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**By Electronic Filing**

British Columbia Utilities Commission
Suite 410, 900 Howe St.
Vancouver, BC V6Z 2N3

**Attention: Patrick Wruck, Commission Secretary**

Dear Mr. Wruck:

## BC Hydro F2020-F2021 Revenue Requirements Applications (RRA)
## Association of Major Power Customers of BC (AMPC)
## Remaining Responses to Information Requests (IRs) on AMPC Intervener Evidence

We are legal counsel to AMPC in this matter and write on its behalf. Further to our letter dated October 23, 2019, Commission Order G-268-19, and our IR responses filed on January 10, 20120, we enclose for filing the remaining responses to IRs from the following parties:

- BC Utilities Commission;
- Clean Energy Association of British Columbia (CEABC); and
- Commercial Energy Consumers Association of British Columbia (CEC).

If you have any questions, please contact the writer.

Yours very truly,

(for) Matthew D. Keen

CAN_DMS: \131487591\1

**1.0 Reference: RECOVERY OF FULL REVENUE REQUIREMENT**
**Exhibit C11-11, Association of Major Power Customers of BC**
**Evidence, Pre-Filed Testimony of InterGroup Consultants,**
**Section 4.2, p. 20, Appendix A, p. A-11**
**Deferral Account Rate Rider (DARR)**

In Association of Major Power Customers of BC's (AMPC) evidence, InterGroup Consultants state:

> Including setting the DARR to 0%, BC Hydro is able to propose rate increases to permit the full F2020 costs to be recovered, including full collection of the desired $712 million ROE [return on equity], with limited net increase to customer bills. This means that rate reductions that may have otherwise been mathematically possible with the declining balances in the deferral accounts (notwithstanding the past policy that locked in the DARR at 5%) will not be seen by customers.
>
> […]
>
> The BCUC should find that absent the redirection of Deferral Account Rate Rider funds into a Government-directed ROE, customers would have seen a material rate reduction in F2020, all else being equal.

On page A-11 of Appendix A to their Pre-filed Testimony, InterGroup Consultants provide a table to illustratively show the impact on the cost of energy deferral accounts of a 5 percent DARR for fiscal 2020 and fiscal 2021 (F2020 and F2021). InterGroup Consultants also state that "the transfer of this allotment to general revenues has not yet been approved by the BCUC for F2020 and F2021."

1.1 Please clarify how the absence of "the redirection of Deferral Account rate Rider funds into a Government-directed ROE" would have resulted in "material rate reductions" in the Test Period. As part of the response, please quantify the rate reductions, where possible, or include an illustrative example of the rate reduction.

1.2 To the best of your ability, please compare the revenue requirement, the rate impact and the bill impact for each of F2020 and F2021 if British Columbia Hydro and Power Authority (BC Hydro) had proposed to continue collecting the 5 percent DARR pursuant to section 10 of Direction No. 7 versus BC Hydro's current proposal of reducing the DARR to 0 percent.

**Response:**

1.1

The discussions of alternative scenarios related to DARR reflect 2 different regimes that have been in place:

1) The original DARR, arising out of the 2007-2008 RRA Negotiated Settlement Agreement and the related Table Mechanism as discussed in section A.3 of InterGroup's pre-filed testimony.

2) The revised DARR imposed by Government Special Direction No. 7 (Section 10), which forced the DARR rider to 5% and determined the allocation for DARR receipts and Deferral Account balances based on newly imposed formulas.

The comment referenced is in relation to #1 above. For a comparison to the regime under #2 above please see AMPC's response to BCUC IR 1.2 below.

As shown in Table 1, if BC Hydro continued calculating the DARR pursuant to the original DARR table mechanism set out in Decision G-16-09,[1] a DARR refund rider would be set for F2020 of -5.0% based on F2019 year-end balance of -$667.7 million (as the year-end balance is <-$500 million). For F2021, the refund rider would be set at -3.5% (as the year-end balance is between -$350 million and -$400 million). Assuming F2020 and F2021 resulted in no Cost of Energy variances, the year-end balance for F2021 would result in a -2% DARR refund for F2022 (i.e. further reductions to revenue requirement would be anticipated in the future).

[1] It is understood that the DARR is to be set based on Cost of Energy balances at September 30 of the previous year, however monthly data was not available therefore for simplicity end of year balances from the year prior are used.

**Table 1: Approximate DARR Refund for F2020 and F2021 if not redirected by Government ($ Millions) [2]**

| | F2020 | F2021 |
|---|---|---|
| **Beginning of Year Balance** | -667.7 | -378.8 |
| **DARR % (based on Table Mechanism)** | *-5.00%* | *-3.50%* |
| **Recovery to Ratepayers** | **244.5** | **172.0** |
| Adjustments/Other Additions | 59.8 | -3.5 |
| Interest (no adjustments from RRA Update) | -15.4 | -4.0 |
| **Resulting End of Year Balance** | **-378.8** | **-214.3** |

Against this backdrop, BC Hydro would be facing a revenue shortfall for F2020 and F2021 due to increases in costs. As compared to the RRA proposals, however, there would be no opportunity to draw down the Deferral Account balances, as they are required as part of the ongoing DARR mechanism (operating as a benefit to ratepayers). As a result, the BC Hydro revenue shortfall would be as follow ($ millions):[3]

| Revised Rate Application ($ Millions) | F2020 | F2021 |
|---|---|---|
| Revenue Shortfall per application | $334.8 | $284.6 |
| Loss of Deferral Account recovery | $403.9 | $226.9 |
| Revised Revenue Shortfall | $738.7 | $511.5 |

On a base rate revenue of approximately $4.9 billion,[4] this revised revenue shortfall indicates a need for rate increases of 15.1% in F2020, reduced to 10.4% in F2021 (i.e., a rate reduction for F2021 of 4.6% compared to F2020 rates). This is the most accurate portrayal of the impact of internal cost pressures BC Hydro and the BC Government are imposing on customers, unmuted by fortunate Deferral Account balances.

Alternatively, BC Hydro and the BC Government could have not sought rate increases in the noted years, and recorded a combined $1.25 billion under-recovery of the desired Revenue

[2] Based on Appendix A – Evidentiary Update, Schedules 2.1 for Beginning of Year Balance F2020, adjustments/other additions and interest (which note: for simplicity was not adjusted based on the account changes that would have occurred in F2021 if this was enacted). DARR Recovery amount calculated based on same Appendix, Schedule 14.0, as the DARR percentage multiplied by forecast domestic revenue from lines 11 – 17 (again this was not adjusted for F2021, which would be reduced as a result of changes occurring in F2020 for rates based on this example).
[3] Revenue Shortfall per application from Appendix A – Evidentiary Update, Schedule 1.0, line 29. Loss of Deferral Account recovery from Appendix A – Evidentiary Update, Schedule 1.0, line 11.
[4] Appendix A – Evidentiary Update, Schedule 1.0, line 28

Requirement over the 2 years, which would still have permitted a positive ROE of almost $200 million over the two test years (i.e., the combined target ROE over these two years totals $1.424 billion).

The above calculations are simplified to ignore feedback into finance expense and cash flows, which might otherwise affect the values to a relatively small degree.

1.2

If BC Hydro proposed to continue collecting the 5 percent DARR pursuant to section 10 of Direction No. 7 versus BC Hydro's current proposal of reducing the DARR to 0 percent, the DARR would be maintained at 5% in each test year (based on Section 10(1) of Directive No. 7).

The equation set out in Section 10 would look approximately as follows (assuming a 5% DARR for F2020 applied to $4,889.1 million in revenue totals $244.5 million, F2021 at $4,913 million in revenue totals $245.7 million) [5]:

<u>Equation 1:</u> DARR(Rev) = amount accounted for as revenue = DARR - (X/5) x DARR

<u>Equation 2:</u> DARR(DA) = amount amortized from the net balance of the Cost of Energy deferral accounts = (X/5) x DARR

**F2020:**

DARR (Rev) = $244.5 million – (-5/5) x $244.5 million = <u>$488.9 million</u>

DARR (DA) = (-5/5) X $244.5 million = negative <u>$244.5 million</u>

For F2021, the DARR would again remain at 5% per Section 10(1). The balance for opening F2021 would be:

[5] Calculated as 5% of domestic revenues from Appendix A from the Evidentiary Update, Schedule 14.0, lines (where domestic revenue is sum of lines 11 – 17.

| **Balance** | **$ Millions** |
|---|---|
| Opening F2020 | -$667.7 |
| Transferred to BC Hydro revenues in F2020 | $244.5 |
| Adjustments F2020[6] | $59.8 |
| Interest (ignored for purposes of response) | $0 |
| **Opening F2021** | **-$363.4** |

The opening F2021 balance of negative $363.4 million would lead to an 'X value' (from the reference table in Direction No.7) of -3.5. The resulting DARR calculation would be:

DARR (Rev) = $245.7 million – (-3.5/5) x $245.7 million = $417.7 million

DARR (DA) = (-3.5/5) X $233.4 million = - $172.0 million

Based on the above, with the Special Direction No. 7, Section 10 rules in place, BC Hydro would have had a 5% DARR throughout F2020 and F2021, and would have seen revenue benefits of $488.9 million in F2020 and $417.7 million in F2021.

Note that under this approach, BC Hydro would not have been able to impose the Deferral Account recovery mechanism described in Appendix A Schedule 2.1, which benefits revenue requirement to a total of $403.9 million in F2020 and $226.9 million in F2021.

As a result, the BC Hydro situation would appear to be as follows ($ million) absent any small adjustments for cash flow or working capital revisions:

[6] Appendix A – Evidentiary Update, Schedule 2.1, sum of lines 24 and 27 (Deferral Account Additions & Adjustment to Opening Balance)

| **Revised Rate Application ($ Millions)** | **F2020** | **F2021** |
|---|---|---|
| Revenue Shortfall per application | $334.8 | $284.6 |
| Loss of Deferral Account recovery | $403.9 | $226.9 |
| Revised Revenue Shortfall pre-DARR | $738.7 | $511.5 |
| Less: Revenue Benefits from DARR per SD7, s.10 | $488.9 | $417.7 |
| **Revised Revenue Shortfall** | **$249.8** | **$93.8** |

On a base rate revenue of approximately $4.9 billion, this indicates a need for rate increases of 5.1% in F2020 reduced to 1.9% in F2021 (i.e., a rate reduction in F2021 of 3.2%) on top of a 5% DARR.

The main reason for the different outcomes is that under the Direction No. 7, s.10 approach, the Deferral Accounts would be drawn down to the benefit of BC Hydro revenues, but not the entire way to $0, while the BC Hydro RRA as filed draws these accounts down to $0 on a forecast basis.

To be clear, however, InterGroup's recommendation as quoted in the preamble was not in relation to Direction 7 Section 10, but to comparing to how the DARR was intended to be used as a short-term rider to collect/refund for cost of energy variances (as per Decision G-16-09).

**2.0 Reference: INDEPENDENTLY ESTABLISH FAIR RETURN ON EQUITY**
**Exhibit C11-11, Association of Major Power Customers of BC Evidence, Pre-Filed Testimony of InterGroup Consultants, Section 4.4, pp. 21–23; Exhibit B-1, Application, Section 8.3, p. 8-8**
**Review scope of BC Hydro return on equity**

InterGroup Consultants introduce several factors that should be considered when reviewing BC Hydro's ROE, which include:

- The extent to which the "equity" reported is in fact BC Government investment in the utility in the first place;
- The extent of risk actually borne by the shareholder considering the range of regulatory directives, tools and deferral accounts; and
- The extent to which an issue caused by Provincial Policy has undermined rate competitiveness.

On page 23, InterGroup Consultants recommend that "The BCUC should issue directives out of this proceeding that provide a clear scope for the coming ROE review so as to deal with matters prior to F2022. BC Hydro should be expected to provide materials to respond to this scope."

In its Application, BC Hydro states:

> BC Hydro's return on equity is prescribed by section 3 of Direction No. 8 as a specific dollar amount of $712 million per fiscal year in each of fiscal 2020 and fiscal 2021…
>
> For fiscal 2022 onwards, the BCUC will be able to determine BC Hydro's Return on Equity. In the Comprehensive Review Report, the Government of B.C. indicated that it may provide policy guidance to the BCUC to inform this process.

2.1 Considering that the government may provide policy guidance in the Cost of Capital review for F2022 onwards, please explain the advantages and potential risks if the Panel in this F2020-F2021 Revenue Requirements Application (RRA) proceeding issues directives relating to a future ROE review.

**Response:**

2.1

The advantages of this Panel providing directives relating to the future ROE review is that all parties, including the Government of B.C., will be able to transparently benefit from the BCUC's independence and expertise in identifying priority issues and principles regarding the BC Hydro ROE, taking into account ratepayer interests and ongoing BCUC regulation of BC Hydro revenue requirements and rates. Panel directives for a subsequent hearing are of assistance to all parties. Staying silent in anticipation of potential future (but currently unknown) government direction risks policy choices made without the benefit of BCUC expertise, independence and process. Recommendations made to BC Hydro in the normal course are important and part of the BCUC's current legislative mandate to exercise general supervision over public utilities and set just and reasonable rates. Government can issue directions to both BC Hydro and the BCUC notwithstanding BCUC direction to BC Hydro, but the BCUC should not shrink from its mandate in anticipation of Government direction.

Further, in the event the BCUC provides direction on topics that require preparation of information or studies in support of a future BC Hydro filing, it is important to identify these early so BC Hydro can get the necessary materials prepared. Leaving these aspects of scope-setting until after a filing is too late.

There is a "risk" that Government policy direction, if any, overrides or reverses BCUC direction – as is the prerogative of government under the *UCA*. That "risk" is not a reason for the BCUC to avoid directing the most reasonable orderly process consistent with today's information. The only issue in this instance is whether or not, prior to any policy direction it might make, the Government of B.C. will have the benefit of the BCUC's independent advice and expertise as to priority issues and principles.

The above also responds to CEC IR 3.1, CEC IR 4.1 and CEC IR 4.2.

**3.0 Reference: EXCESSIVE REGULATORY ACCOUNT COMPLEXITY**
**Exhibit C11-11, Association of Major Power Customers of BC**
**Evidence, Pre-Filed Testimony of InterGroup Consultants,**
**Section 4.5, p. 24**
**Government-owned Canadian utilities**

In AMPC's evidence, InterGroup Consultants state:

> Complexity: Perhaps the most notable feature of BC Hydro's regulatory and deferral accounts that is not directly addressed by the AG is the issue of the complexity associated with these accounts, which makes transparent regulation difficult. No government owned Canadian utility appears to maintain regulatory accounts with as broad a scope and function as BC Hydro.

3.1 Please identify the government-owned Canadian utilities that InterGroup Consultants reviewed when evaluating the complexity of BC Hydro's regulatory accounts.

**Response:**

3.1

InterGroup Consultants has experience in multiple Canadian jurisdictions and routinely reviews revenue requirement applications. Specifically, for government-owned Canadian jurisdictions the below jurisdictions have been reviewed.

For the jurisdictions that use regulatory accounts, the approach is much clearer than BC Hydro, mainly as these accounts operate outside of rate base (where relevant) and revenue requirement. In addition, these accounts are easily reconciled back to a single item of revenue requirement (such as interest expense, DSM or depreciation).

To be clear, some regulatory deferral type accounts are entirely related to balancing impacts on ratepayers over time (such as fuel or supply cost accounts) and operate fully within the regulatory arena. Revenue requirements are set based on one set of assumptions, and if different facts arise the differences are deferred. Other accounts, however, are mostly about reconciling between regulatory reality (focused on important issues of just and reasonable rates and fairness) and accounting standards (focused on other presentation priorities). These accounts are not "regulatory" accounts per se – they are simply a bridge to help understand the two different equally valid approaches. To understand the regulatory reality, one need not necessarily dig deeply into these accounts – one just needs to look at properly prepared regulatory statements. An example is the Manitoba Hydro depreciation "account" – the regulatory reality is clear, Manitoba Hydro is to use the Average Service Life (ASL) procedure,

and all information for regulatory purposes can be presented using the ASL values. Issues of the need for an "account" only arise because Manitoba Hydro has independently determined that it desires to use the alternative Equal Life Group (ELG) procedure for its financial reporting. This means that the financial reporting values are different than the regulatory values. The account is a way for the individuals who rely on the company's financial reports to understand that the regulator has not accepted this depreciation procedure, so the added values the accountants elect to book as accelerated ELG depreciation each year have not yet been addressed via rates, as such aggressive accelerated depreciation would be unfair to current ratepayers.

The same is true of DSM – if there are true bulk power benefits, the DSM spending should be deferred and amortized the same as a capital asset providing bulk power benefits would be deferred and amortized/depreciated. Properly presented, it should be no more complicated to report on DSM than any capital asset.

Examples of various regulatory accounts are provided in the table below. Note that for utilities such as Manitoba Hydro, every account noted is simply a reconciling entry between the regulatory reality and what would otherwise be presented on the financial statements. Newfoundland Hydro is the opposite – all accounts noted below are entirely about balancing timing effects within the regulatory arena. None, however, has a wide a range and complexity of accounts as BC Hydro.

| **Utility** | **Regulatory/Deferral Accounts** | **Magnitude of Balance in relation to Revenue Requirement** | **Reference** |
|---|---|---|---|
| Manitoba Hydro | Power Smart Programs, Depreciation Methodology (capturing difference of ASL for regulatory accounting, ELG for financial reporting), Deferred Ineligible Overhead (captures variance between financial reporting with IFRS and regulatory reporting for rates), gain/loss on disposal of assets, site restoration costs, regulatory costs, acquisition costs, affordable energy fund, Conawapa generation preliminary costs amortization, DSM deferral balance | Closing Balance of $0.598 billion forecast for 2018/19 compared to total revenue requirement of $2.146 billion | PUB/M I-1a-f in the 2017/18 & 2018/19 GRA: https://www.hydro.mb.ca/docs/regulatory_affairs/pdf/electric/general_rate_application_2017/information_requests/round_1_pub_irs.pdf<br><br>2018/19 forecast revenue requirement for 2018/19 from Hydro's MH16 Update, page 1: https://www.hydro.mb.ca/docs/regulatory_affairs/pdf/electric/general_rate_application_2017/03.6_appendix_3.6_updated_financial_forecast_mh16_update.pdf |

| Utility | Regulatory/Deferral Accounts | Magnitude of Balance in relation to Revenue Requirement | Reference |
|---|---|---|---|
| Newfoundland and Labrador Hydro (NLH) | Rate Stabilization Plan (RSP) for Island Interconnected System. Currently RSP is comprised of the following three main components: Hydraulic Variation, Fuel Price Variation and Customer Load Variation. The variations are allocated to customers and charged annually as a RSP rider.<br><br>NLH also maintains:<br><br>- Energy Supply Cost Variance Deferral Account that captures variations resulting from both the price and volume of the thermal generation sources, and variations resulting from the volume of the power purchases. The deferral account has a ±$500,000 threshold in a calendar year. Disposition of balance in this account is done through the application by NLH no later than the 31st day of March each year.<br><br>- Excess Earnings Account to credit excess earnings.<br><br>- Return on Equity (ROE) Rate Change Deferral Account to capture required adjustments between test years when NLHs target ROE percentage must be adjusted as required to equal the ROE approved for Newfoundland Power.<br><br>- Holyrood Conversion Rate Deferral Account which defers the cost impacts of variances from the approved test year conversion rate [fuel efficiency] in excess of $500,000. | Total RSP balance at $9.9 million by end of September 2019 [compared to $643 million revenue requirement for 2019].<br><br>$49.8 million forecast by end of 2019 [ 2017 GRA Compliance Filing Exhibit 4, Appendix C]<br><br>$0.5 million forecast by end of 2019 [ 2017 GRA Compliance Filing Exhibit 4, Appendix C] | 2017 GRA Compliance Filing, page 9. http://pub.nf.ca/applications/NLH2017GRACompliance/application/NLH%202017%20GRA%20Compliance%20Application%20-%202019-07-11.PDF [accessed on January 2, 2020].<br><br>2017 GRA Compliance Filing, Exhibit 15, pages from 10 of 48 through 17 of 48. http://pub.nf.ca/applications/NLH2017GRACompliance/application/NLH%202017%20GRA%20Compliance%20Application%20-%202019-07-11.PDF [accessed on January 2, 2020].<br><br>2017 GRA Compliance Filing, Exhibit 8, Appendices A, B and C. http://pub.nf.ca/applications/NLH2017GRACompliance/application/NLH%202017%20GRA%20Compliance%20Application%20-%202019-07-11.PDF [accessed on January 2, 2020].<br><br>NLH 2017 GRA, Volume I, page 6.6. http://pub.nf.ca/applications/NLH2017GRA/applications/NLH%202017%20General%20Rate%20Application%20-%20Volume%20I%20-%20Revision%205%20-%202018-07-04.PDF [accessed on January 2, 2020]. |

| Utility | Regulatory/Deferral Accounts | Magnitude of Balance in relation to Revenue Requirement | Reference |
|---|---|---|---|
| SaskPower | SaskPower does not use deferral accounts or rate riders. | | SaskPower 2018 Rate Application, page 20, available online: https://www.saskratereview.ca/docs/saskpower2017/saskpower-2018-rate-application.pdf. |
| Northwest Territories Power Corporation (NTPC) | NTPC has a Territorial Rate Stabilization Fund (Stabilization Fund) which was created to help to keep electricity prices stable when fuel prices or hydroelectric outputs fluctuate.<br><br>NTPC also maintains some reconciling accounts such as for Employee Future Benefit accruals. | TRSF November 2018 balance $4.1 million.[7] | NTPC website: https://www.ntpc.com/about-ntpc/news-releases/2017/07/07/pub-approves-discontinuation-of-fuel-refund-rider |
| Yukon Energy Corporation (YEC) | Yukon Energy maintains two mechanisms or accounts designed to stabilize rates and revenues: Deferral Fuel Price Variance Account (DFPVA) that captures variances (plus or minus) in fuel price per litre from GRA forecast fuel prices and Yukon Energy maintains Low Water Reserve Fund which was "established to ensure that ratepayers, rather than YEC, covered the risk of changes in grid diesel generation due to fluctuations in hydro generation resulting from factors outside of the utility's control (such as drought conditions).<br>Both accounts are maintained and reported separately from the revenue requirements and refunded/collected through riders. | DFPVA October 31, 2019 balance at $2.9 million [compared to $77.9 million consolidated revenues]<br><br>LWRF March 31, 2019 balance at $2.526 million | YEC's 2017/18 GRA, page 3-23 http://yukonutilitiesboard.yk.ca/pdf/YEC_2017-18_GRA/YEC_2017-2018_General_Rate_Application_FINAL_WEB_VERSION.pdf [accessed on December 31, 2019].<br><br>YEC and ATCO Electric Yukon Rider F rate change advisory letter to YUB. http://yukonutilitiesboard.yk.ca/reports/ [accessed on January 2, 2020].<br><br>YEC LWRF annual report, Table 2. http://yukonutilitiesboard.yk.ca/pdf/Reports/Updated_2018__2018_LWRF_Annual_Report__ERA_Filing.pdf [accessed on January 2, 2020].<br><br>Consolidated revenues are from Table 1-3 of YEC's 2017/18 GRA compliance filing http://yukonutilitiesboard.yk.ca/pdf/YEC_2017-18_GRA/Compliance_Filing_-_Sept_2019.pdf [accessed on January 2, 2020]. |

[7] NTPC Territory-wide Rate Stabilization Fund Rider Application to NWT Public Utilities Board on March 15, 2019, Schedule 1.

| Utility | Regulatory/Deferral Accounts | Magnitude of Balance in relation to Revenue Requirement | Reference |
|---|---|---|---|
| Qulliq Energy Corporation (QEC) | Qulliq Energy Corporation (QEC) maintains Fuel Stabilization Rate Fund that captures the variances in diesel fuel prices [the actual/forecast fuel price compared to the last GRA approved fuel price].<br>If the fund balance exceeds the threshold of plus or minus $1 million within a six month period, QEC files an application with the Responsible Minister for approval of a Nunavut wide fuel rider designed to recover or refund the balance in the fund over a suitable period targeting a zero balance at the end of the six month period. | Below $1 million as the rider expired on March 31, 2019. | Qulliq Energy Corporation, https://www.qec.nu.ca/customer-care/general-information/what-fuel-stabilization-rate [accessed on January 2, 2020].<br><br>https://www.qec.nu.ca/sites/default/files/fsr_application_november_2018_complete_with_schedule-_english.pdf [accessed on January 2, 2020]. |

**4.0 Reference: FINANCE CHARNGES AND DEBT MANAGEMENT REGULATORY ACCOUNT**
**Exhibit C11-11, Association of Major Power Customers of BC Evidence, Pre-Filed Testimony of InterGroup Consultants, Section 5.2, pp. 41–43**
**Finance charges forecast**

On page 42, InterGroup Consultants discuss BC Hydro's actual borrowings in F2020 to date and the interest rates with respect to BC Hydro's long-term debt. InterGroup Consultant also compare these rates with the average long-term forecast debt rate used to forecast the Test Period revenue requirement, and state "[i]f actual experience to date for F2020 for interest rates is carried over into the test years at 2.95%, this would reduce finance charges materially."

With respect to BC Hydro's short-term debt, InterGroup Consultants state that BC Hydro's forecast is based on the Treasury Board of BC's January 2019 forecast. InterGroup Consultants further state:

> Since January 2019, the BC Treasury Board's outlook for interest rates has lowered, with its First Quarterly Report 2019/20 in September 2019 lowering the F2020 rate from 2.35% to 1.73% and F2021 rate from 2.69% to 1.71%. Based on current forecast short-term debt, this would appear to result in a decrease of short-term debt interest costs from $69.3 million to $51.0 million in F2020 and from $81.9 million to $52.1 million in F2021.

InterGroup Consultants state on page 43 of AMPC's evidence that "BC Hydro should update its finance charge forecasts for relevant known conditions and values to ensure the best available data is used to set rates. This is particularly true in an era where utilities have exhibited a trend of overforecasting finance charges (due to difficult to forecast market conditions)."

4.1 To the best of your ability, please explain the magnitude and impact to the Test Period revenue requirement and rates if BC Hydro were to update its Test Period forecasts based on the known conditions and values as recommended by InterGroup Consultants (i.e. to include the actual borrowings in F2020 to date and the interest rates in the BC Treasury Board's September 2019 quarterly report). Please quantify where possible.

4.2 Please elaborate on what are the difficult to forecast market conditions that could impact the accuracy of finance charge forecasts.

4.3 Please discuss what are industry accepted methods to forecast finance charges for the purpose of determining the revenue requirements. Please provide references where possible.

4.3.1 Please evaluate whether BC Hydro's methodology to forecast finance charges is consistent with known accepted industry practice.

**Response:**

4.1

As explained in section 5.2 of InterGroup's evidence, page 42, the impact on test year revenue requirement is as follows:

- For long-term debt – due to BC Hydro's considerable amount of hedging for the test years, it is harder to estimate the impact on revenue requirement of maintaining a 2.95% interest rate based on recent borrowings. However, it is estimated that the impact on the unhedged portion of long-term debt may reduce the finance charge by about $2 million for 2020 and $7 million for 2021.[8] It is not as clear how these rates could impact the hedged portion of long-term debt, including the debt management regulatory account, which uses a point in time interest rate to calculate hedged positions (i.e. subject to large changes depending on interest rates).
- For short-term debt - lowering the F2020 rate from 2.35% to 1.73% and F2021 rate from 2.69% to 1.71% would appear to decrease finance charges by $18.3 million in F2020 (from $69.3 million to $51.0 million) and by $29.8 million in F2021 (from $81.9 million to $52.1 million).
- For sinking funds – BC Hydro did not provide the background calculations supporting interest impacts of sinking funds in its filing.[9] However sinking fund income is included as an offset to finance charges, forecast at $7.8 million for F2020 and $7.7 million for F2021. Likely changes in sinking fund rates would be smaller in magnitude than the

[8] For example, BC Hydro's response to AMPC IR No 2.26.1 Attachment 1 shows that for fiscal 2020 remaining new unhedged long-term debt is $425 million at 3.76% interest rate [$8.7 million interest expense shown by BC Hydro compared to $15.9 million full year interest expense assuming new debt borrowed about middle of fiscal year] and $500 million for fiscal 2021 at 4.06% interest rate [$13.5 million interest expense shown by BC Hydro compared to $20.3 million full year interest expense assuming new debt borrowed in fourth month of the fiscal year]. With interest rate at 2.95% for both fiscal years, interest expense for $425 million would reduce by about $2 million for 2020 [$425M*2.95%/12*6.5 months=$6.8M-$8.7M], and for 2021 reduction in interest expense would be about $7 million [($425M*2.95%=$12.5M-$15.9M) + ($500M*2.95%/12*8=$9.8M-$13.5M).

[9] Appendix A, Schedule 8.0 details Finance Charges, with change in sinking fund and sinking fund income hard entered (i.e. not easy to reconcile how sinking fund rate changes may impact annual finance charges).

> interest rate impacts noted above, potentially on the order of $3 million over the past few years.[10] It is possible revenue requirement impacts would be within this range.

BC Hydro should be able to easily quantify these changes in an undertaking or compliance filing, but the likely impact on revenue requirement of all three types of debt could be in excess of $20 million in F2020 and upwards of $40 million in F2021. This is approximately equal to a 0.45% rate decrease in F2020 and a 0.75% rate decrease in F2021 (as a percentage of total revenue requirement of approximately $5.2 billion).

4.2

Interest rate forecasts are a consistent challenge for utilities and utility regulators. In its 2018 Generic Cost of Capital proceeding, the Alberta Utilities Commission (AUC) recognized that future growth expectations are far from certain and are dependent on many factors, both domestic and international.[11] In reaching its decision on the appropriate regulated cost of capital, the AUC stated it:

> …considered the evidence filed on the record of this proceeding with respect to future expectations for global economic and Canadian capital market conditions. Given the expectations of diminishing national GDP growth rates, moderately higher inflation to reach the mid-point of the Bank of Canada's target range, increasing short-term interest rates, a flattening yield curve, but uncertain long-term interest rates and market uncertainty with respect to international trade, the Commission finds that these factors result in a similar offset and together indicate that the approved ROE for 2019 and 2020 should be the same or similar to the value set for 2018.[12]

The AUC Decision provides a useful summary of the variety of considerations that can influence the preparation of interest rate forecasts and cost of capital.

Note that the difficulty forecasting interest rate expense in now way undermines (and in fact supports) the concept of using the latest most up-to-date values in determining rate levels.

[10] See Table 5-8 from InterGroup evidence, page 43
[11] Paragraph 195 of AUC Decision 22570-D01-2018. Available: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2018/22570-D01-2018.pdf. Accessed January 3, 2020.
[12] Paragraph 207 of AUC Decision 22570-D01-2018. Available: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2018/22570-D01-2018.pdf. Accessed: January 3, 2020.

4.3

Mr. Bowman and Ms. Davies are not experts in finance and capital markets and do not generally participate in the preparation of interest rate forecasts.

Interest rate forecasts are consistently challenging for utilities and utility regulators. For example, in its 2016 rate application, Manitoba Public Insurance (MPI) provided a report on the performance of the Standard Interest Rate Forecasts (SIRF) it relied on over an eight-year period. MPI's SIRF was based on an average of the forecasts for the 10-year Government of Canada interest rate from the five major banks and Global Insight.[13] The report indicated that MPI's SIRF exceeded actual yields by a wide margin, 1.7% on average, and that simply using the actual prevailing rates (or a 'naïve forecast') instead of the SIRF would have produced substantially more accurate results.[14]

Mr. Bowman and Ms. Davies have experience reviewing the reasonableness of Interest rate forecasts used by utilities in a number of jurisdictions in Canada and appropriate regulatory methods to address the inherent uncertainty and potential volatility in interest rates. In InterGroup's experience, a key regulatory principle for improving the reasonableness of test-year forecasts of interest rates and finance charges is that they should incorporate the most recent available actual information and forecasts. It is common for regulators to require utilities to update their interest expense forecasts prior to final approval of rates, where updated information indicates a material variance from originally filed information. InterGroup's evidence recommends a similar approach for BC Hydro at pages 43 and 44.

For example, the application of this principle is clearly set out by the Manitoba Public Utilities Board (MPUB) in its recent decision on the 2019/20 Centra Gas General Rate Application where the MPUB stated:

> The Board finds that Centra's 2019/20 revenue requirement is to be reduced by $0.664 million due to the decrease in forecasted Finance Expense.
>
> The Board does not accept Centra's argument that its revenue requirement should not be adjusted to reflect the updated Finance Expense forecast. The updated information filed on July 24, 2019 represents the best forecast information available to the Board at the time of the hearing and is derived from independent third-party forecasters. While the Board acknowledges that the July 24, 2019 forecast is a forecast, it most realistically reflects Centra's borrowing needs and the interest rate environment in the Test Year given that it is based on Summer 2019 forecasting. If Finance Expense was not updated to reflect the

[13] See page 46 of Manitoba Public Utilities Board Order 162/16. Available: http://www.pubmanitoba.ca/v1/pdf/mpi16/162-16.pdf. Accessed January 2, 2020.
[14] Available: http://www.pubmanitoba.ca/v1/pdf/mpi17/mpi-7.pdf

> most current information filed with the Board, an additional $0.664 million would be included in revenue requirement and therefore recovered from consumers in rates. Given that the updated forecast reflects an expectation that Finance Expense is forecast to be $0.664 million lower in 2019/20, by not requesting a change in its revenue requirement, Centra is in effect asking that the additional consumer funds flow to net income, above and beyond the level of net income approved by the Board. The Board also notes that, despite Centra's position on not adjusting Finance Expense, Centra requested that the Board make other adjustments arising from the July 24, 2019 update, including the change in volume forecasting for the Power Station customer class and the negative contingency now incorporated in the detailed Operating and Administrative program budget.
>
> The Board does not agree that its revenue requirement decisions in a GRA proceeding should be based only on the forecast information provided in Centra's filing, without any updating for more current information. Directive 4 from Order 85/13 was made in order to obtain the most current interest rate forecasts so that the Board could determine whether or not the Finance Expense should be updated. The Board used that information in the 2013/14 GRA to update the revenue requirement, finding that a $200,000 decrease in Finance Expense was material. The Board directs Centra to file in future GRA proceedings information regarding any post-filing events or changes that would have a material impact on rates if reflected in Centra's revenue requirement. This information should be filed in the proceeding at the earliest opportunity for the Board's review and consideration.[15]

InterGroup is aware of several other instances where this principle has been applied in regulated jurisdictions in Canada including:

<u>Newfoundland and Labrador</u>

In the Settlement Agreement related to its 2018 and 2019 General Rate Application, Newfoundland and Labrador Hydro agreed to reduce its forecast interest costs to reflect savings associated with borrowing from the provincial government and not in the capital markets as forecast in the application.[16]

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[15] Manitoba Public Utilities Board Order 152/19 dated October 11, 2019. Available: http://www.pubmanitoba.ca/v1/proceedings-decisions/orders/pubs/2019-orders/152-19.pdf. Accessed January 2, 2020.

[16] Paragraph 12 (a) (ii) of the settlement agreement dated April 11, 2018. Available: http://www.pub.nf.ca/applications/NLH2017GRA/settlement/NLH%202017%20GRA%20-%20Settlement%20Agreement%20-%202018-04-11.pdf. Accessed January 3, 2020. The settlement agreement was

Alberta

In its Decision with respect to the ATCO Electric Ltd. (AET) 2018-2019 Transmission General Tariff Application, the AUC stated:

> Given the approval for the continued use of the debt rate deferral account for 2019, the Commission needs to determine a reasonable forecast for the cost of debt to be used for the second test year. As the actual cost of debt and the issue amount for AET's 2018 debt issuance is known, the Commission directs AET, in the compliance filing, to update its application in all aspects to reflect the 2018 actual cost of debt resulting from the actual 2018 long-term debt issues.[17]

Northwest Territories

As part of its 2016/19 General Rate Application, the Northwest Territories Power Corporation updated its forecast finance expense prior to the oral hearing primarily to reflect the refinancing of a higher interest debenture. The update was provided approximately eight months following the filing of the original application.[18]

InterGroup notes that even where deferral accounts are in place, regulators still require utilities to update their finance expense forecasts to incorporate more recent actual information. The AET tariff application is one recent example of this. The presence of a deferral account should not be a substitute for ensuring approved rates incorporate the best available actual information.

4.3.1

A full analysis of BC Hydro's interest rate forecasting approach with industry standards was not part of the InterGroup assignment scope and, other than the above noted comparisons, would be a substantial undertaking outside the scope of an IR response. InterGroup's review of BC Hydro's methodology focused on its use of stale forecasts and the effect of updating them with current information, especially given BC Hydro's choices to update certain data in its Evidentiary Update. More substantial questions, such as the source of BC Hydro's independent forecasts, the approaches to weighting these forecasts, the management of outliers, the importance of shorter-dated forecasts versus longer-dated, and the management of forecasters who have proven to be of lower reliability were not reviewed.

approved by the Newfoundland and Labrador Board of Commissioners of Public Utilities in Order No. P.U. 16(2019). Available: http://www.pub.nf.ca/orders/order2019/pu/PU16-2019.pdf. Accessed January 3, 2020.

[17] Paragraph 735. Decision 22742-D01-2019. Available: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2019/22742-D01-2019.pdf. Accessed January 3, 2020.

[18] NTPC letter to the NWT Public Utilities Board dated March 1, 2017. Available: https://www.nwtpublicutilitiesboard.ca/sites/default/files/supporting/35%202017%2003%2001%20NTPC%20Letter%20and%20%202016_19%20General%20Rate%20Application%20Phase%20I%20Update%20Schedules%20Mar%201%2C%202017.pdf Accessed January 2, 2020.

**5.0 Reference: DEPRECIATION**
**Exhibit C11-11, Association of Major Power Customers of BC Evidence, Pre-Filed Testimony of InterGroup Consultants, Section 5.4, pp. 48–49, 54;**
**Depreciation methodology**

InterGroup Consultants discuss BC Hydro's Depreciation Methodology on page 48 of AMPC's evidence:

> BC Hydro's current depreciation expense is based on parameters and methodology from its depreciation study for year ending March 31, 2005. This study was undertaken by external consultant Gannett Fleming approved as part of the F2007-F2008 RRA negotiated settlement by the BCUC in Order G-143-06. Additionally, BC Hydro implemented some new component asset classes in the F2012-F2014 RRA as a result of IFRS implementation. At that time, BC Hydro had noted it expected to complete a depreciation study before the next RRA, however BC Hydro later decided against it.

InterGroup Consultants further state on page 49:

> Currently, BC Hydro indicates that even though it has been 15 years since its last depreciation study it has no plans to update its depreciation parameters, as it has no indication that asset life expectations have changed in a significant way that would have a material impact on depreciation expense. BC Hydro also states that its adoption of IFRS did not change the accounting principles applicable to the depreciation of property, plant and equipment. Therefore, BC Hydro believes that the cost and effort of performing the study would outweigh the benefits. For comparison, the cost of the F2005 study, not including internal BC Hydro staff efforts, cost $161,025.
>
> This is an unusual conclusion. There are many accounts in BC Hydro's 2005 study that did not have extensive retirement experience, and the almost 15 years of time that have passed would typically help to review the adequacy of current service life estimates for these accounts, as well as determine if asset characteristics, technological advances or operational, maintenance or environmental considerations have resulted in changes to the depreciation parameters currently in place.

InterGroup Consultants conclude on page 54 of AMPC's evidence:

> There is significant basis for concern that BC Hydro's depreciation rates do not reflect reliable estimates of asset life and the consumption of service value in

the test years. The BCUC should direct BC Hydro to complete a full depreciation study including assessment of the adequacy of accumulated depreciation balances. Such study should be completed prior to the next RRA and be slated for detailed review and testing at that time.

5.1 For Canadian utilities of similar size to BC Hydro, please provide the average time between full depreciation studies. To the best of your knowledge, please discuss whether comparable utilities provide updated depreciation studies on a regular interval?

5.2 Please discuss whether there are any specific changes that have occurred since 2005, such as technological advances or operational, maintenance or environmental considerations, that would materially impact the service life of BC Hydro's capital assets. If so, please describe these changes and the magnitude of the impact to the test period revenue requirement and rates.

5.3 Considering BC Hydro recently adopted International Financial Reporting Standards (IFRS), please discuss whether AMPC expected to see accounting principal changes regarding the treatment of depreciation. If so, please describe these accounting principal changes and the magnitude of the impact to the test period revenue requirement and rates.

**Response:**

5.1

In InterGroup's experience, many energy utilities undertake full depreciation studies every 3-5 years regardless of utility size, provided as support for rate applications and for testing by the regulator in rate setting.

The pre-filed testimony of InterGroup Consultants Ltd., footnote 105 at page 50, provide the following examples for the 3-5 year timeframe:

> For example, Newfoundland and Labrador Hydro filed a depreciation study in 2012 (for year ending 2009) and in 2017 (for year ending 2015). Manitoba Hydro filed depreciation studies in F2007 for (for year ending March 31, 2005), in 2013 (for year ending March 31, 2010) and in 2015 (for year ending March 30, 2014). Altalink Management Ltd. of Alberta filed transmission depreciation studies to support its 2015-2016 tariff application (for year ending December 31, 2014) and again for its 2019-2021 tariff application (year ending December 31, 2017).

The timeframe between studies for these utilities is 6 years, 4-5 years, and 3 years respectively. InterGroup understands that Manitoba Hydro currently has another depreciation study underway.

Other energy utility examples include:

- ATCO Electric (in Alberta), filed its latest depreciation study 4 years after the last, most recently in support of its 2020-2022 General Tariff Application (for year ending 2018) and prior to that in support of the 2015-2017 GTA (for year ending 2014).[19]
- SaskPower, External depreciation studies were scheduled to be performed every five years. However, the last external depreciation study was completed in 2010 by Gannett Fleming. Due to restraint measures, management decided to defer the next external depreciation study. SaskPower internally reviews depreciation rates annually.[20]
- Northwest Territories Power Corporation, NTPC generally files full depreciation study with every GRA, so average time would be 3-4 years, most recently in support of its 2016/19 Phase I GRA, for year ending March 31, 2015. Prior to that NTPC filed a depreciation study in support of its 2012/14 Phase I GRA for year ending March 31, 2011.[21]
- Qulliq Energy Corporation filed its full depreciation study in its 2010/11 GRA as well as in 2018/19 GRA. The major changes in latest review in the 2018/19 GRA include longer expected life for some assets.[22]
- Yukon Energy Corporation, filed depreciation study with its 2012/13 GRA that reviewed service lives of assets, which Yukon Energy notes decreased the 2012 depreciation expenses by approximately 33% and decreased 2013 depreciation expense by approximately 32%.[23] Yukon Utilities Board in its Order 2018-10

[19]Study in support of 2020-2022 GTA, available online: https://www2.auc.ab.ca/Proceeding24964/ProceedingDocuments/24964_X0033.01_24964-X0033.01BL_0170.pdf, study in support of 2015-2017 GTA available online: https://www2.auc.ab.ca/h007/Proceeding20272/ProceedingDocuments/Attachment%2031.1%20-%20Depreciation%20Study_0187.pdf

[20] SaskPower 2018 Rate Application, Round 1 IRs, SRRP Q19, available online, pdf page 30 of 280: https://www.saskratereview.ca/docs/saskpower2017/saskpower-2018-rate-application-srrp-round-1-irs-q1-to-q148-public.pdf.

[21] Most recent study available in NTPC's 2016/19 Phase I GRA, as explained on page 6-2 and provided as Appendix A, available online: https://www.nwtpublicutilitiesboard.ca/sites/default/files/supporting/1%202016%2006%2030%20NTPC%202016_19%20Phase%20I%20General%20Rate%20Application.pdf

[22] QEC's 2018/19 GRA, page 4-12. https://www.qec.nu.ca/sites/default/files/2018-2019_qec_general_rate_application.pdf [accessed on January 3, 2020].

[23] YEC's 2012/13 GRA, page 3-23 http://yukonutilitiesboard.yk.ca/pdf/YEC%202012%20General%20Rate%20Application/1338_YEC%202012_2013%20GRA%20FINAL_2012%2004%2027%20Tabs%201-11.pdf [accessed on January 3, 2020].

directed YEC to file a full depreciation study with its next GRA, and it is understood a depreciation study is currently underway.[24]

5.2

Other utility depreciation study updates as referenced in response to question 5.1 indicate that material changes to service life of electric utility assets occur in practice for a wide range of reasons, including instances where there is less turnover for these assets that had been previously assumed (i.e., asset lives are extended). A depreciation study update is required to identify the specific changes since 2005 that impact the service life of BC Hydro capital assets.

One of the major inputs to depreciation studies, particularly for large assets like hydraulic generation and transmission, is peer experience (since these large assets typically have relatively small numbers of individuals in any one company, as compared to something like distribution transformers). For this reason alone, there is reason to believe BC Hydro's last study is excessively dated. Further, even in cases where depreciation lives do not change, depreciation expense can change based on the relative balances of accumulated depreciation compared to the calculated (hypothetical) level of depreciation reserve.

5.3

The impact of IFRS on depreciation practice has been an active topic among the utilities reviewed by InterGroup. The basic principle remains the same - allocation of the loss of service value of capital assets to the various time periods over which an asset provides service. But material differences can arise through differences in the application of such concepts as gains and losses on retirement and treatment of Asset Retirement Obligations.

InterGroup does not necessarily expect to see accounting principle changes to the treatment of depreciation upon IFRS adoption. Typically, however, such changes arise from discussions between the utility and their auditors about more nuanced aspects of capital accounting (such as what costs can be capitalized, what constitutes a "unit of property" for tracking and disposal purposes, and whether the asset base is sufficiently "componentized" to permit group accounting calculations). InterGroup did not review such capital asset accounting practices and would not normally be testing such details in the absence of either a detailed depreciation study, or a proposal by the utility to change such practices (often in response to issues raised by auditors). Outside of material changes to componentization, it would not be expected that these changes would drive material impacts on revenue requirement.

[24] YUB Order 2018-10, paragraph 212
http://yukonutilitiesboard.yk.ca/pdf/Board_Orders_2010/Appendix_A_to_Board_Order_2018-10.pdf [accessed on January 3, 2020].

For example, the Alberta Utilities Commission released Rule 026: Regulatory Account Procedures Pertaining to the Implementation of the International Financial Reporting Standards for utilities in 2013. These guidelines outlined reporting requirements for utilities to the AUC upon IFRS adoption, including for depreciation rates, componentization, and componentization of major overhauls (Section j, page 7-8).[25]

The Ontario Energy Board similarly released a Report to utilities on the Transition to International Financial Reporting Standards in 2009. In its Report the Board determined it would facilitate a joint depreciation study for electrical distribution utilities to determine depreciation methodologies and rates appropriate for these utilities under IFRS, including componentization requirements. Electrical utilities retained the option of demonstrating, through a well-founded depreciation study, that the Board should approve specific depreciation methodologies and rates for that utility.[26]

Manitoba Hydro has undergone a number of reviews of its depreciation methodology upon its transition to IFRS, starting with its depreciation study for year ending March 31, 2010 which specifically included an assessment of IFRS related depreciation practices and methodologies.[27]

[25] AUC Rule 026, available online: http://www.auc.ab.ca/Shared%20Documents/rules/Rule026.pdf
[26] OEB Report to the Board, Transition to IFRS, EB-2008-0408, page 20-21, available online: https://www.oeb.ca/oeb/_Documents/EB-2008-0408/IFRS_Board_Report_20090728.pdf
[27] Manitoba Hydro Depreciation Study for year ending March 31, 2010, available online: http://www.pub.gov.mb.ca/exhibits/mh-gra-2012-13-14/appendix_5_7.pdf

**6.0 Reference: COST OF ENERGY**
**Exhibit C11-11, Association of Major Power Customers of BC Evidence, Pre-Filed Testimony of InterGroup Consultants, Section 4.6, p. 30**
**Prudency and least cost utility planning**

In AMPC's evidence, InterGroup Consultants state:

> RECOMMENDATION/CONCLUSION: With a return to full regulation, the BCUC must ensure future rate reviews consider and test the prudence and least cost nature of all costs that continue to be included in revenue requirement (even costs committed in previous periods, which have to date not been properly tested or adjusted in rates). A number of costs are now explicitly acknowledged by either the BC Government (Independent Power Producer costs, Water Rentals) or the BCUC (Capital projects which merited an 'ex post facto' review to determine prudency) as not meeting the test for least cost utility planning or full and transparent regulatory review.

6.1 Please describe what is meant by the term "least cost utility planning."

**Response:**

6.1

Broadly speaking, least cost utility planning methods result in a revenue requirement that includes all reasonable and prudent costs required to provide safe and reliable utility service. Additional discussion this topic is provided in section 2.1 of InterGroup's evidence.

Least cost planning methods are common for regulated utilities. For example, Nalcor (Newfoundland and Labrador) has acknowledged a responsibility to provide least cost power.[28] The BCUC likewise phrased the "fundamental corporate objective" for BC Hydro in an early rate decision as "to generate and distribute electricity to meet the short and long term requirements of British Columbia, at the lowest possible cost to the consumer."[29]

In principle, regulation is meant to mimic competition (insofar as this concept can be stretched to suit natural monopolies). In a competitive environment, any firm cannot permanently incur

[28] See Executive Summary, page 2, of Nalcor's submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project dated November 10, 2011. Available: https://nalcorenergy.com/wp-content/uploads/2016/12/Final_Submission_to_PUB_for_Muskrat_Falls_Review_2011_11_10_all_Volumes3.pdf. Accessed: January 3, 2020.
[29] BCUC Decision re BC Hydro Rate Increase Request, 1986 https://www.ordersdecisions.bcuc.com/bcuc/decisions/en/112026/1/document.do, pp. 9-10.

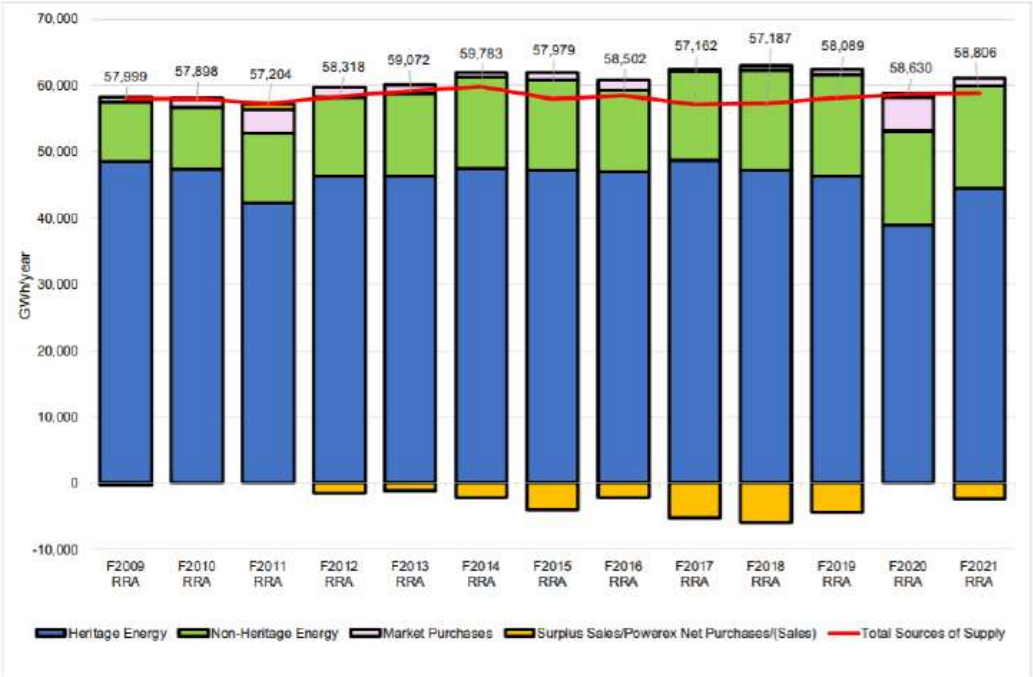
costs above a prudent or "least cost" level and remain competitive, because competitors will adopt such lower cost methods and undercut the higher cost firm. This means all aspects of a firm's operation, including capital investment and operations, must be permanently and repeatedly revisited and challenged to achieve the only level that will allow the firm to remain profitable — least cost operation.

Under a regulatory model, the test should be no different. In each instance, the utility should be required to prove to the regulator that it has achieved the lowest cost possible consistent with reliable and safe service. This includes revisiting past decisions, and taking write-downs or disposals where necessary. This is no different than a competitive firm who has made poor investments - in principle they cannot rely on their customers to continue to fund these investments once they have become "stranded" or replaced by lower cost alternatives.

**7.0 Reference: COST OF ENERGY**
**Exhibit C11-11, Association of Major Power Customers of BC Evidence, Pre-Filed Testimony of InterGroup Consultants, Appendix E, Figure E-1, p. E-4**
**Revenue requirements application source of supply**

Figure E-1 of Appendix E shows the forecast supply mix between heritage, non-heritage (Independent Power Producers) and market energy:

Figure E-1: RRA Source of Supply F2009 to F2021[8]




7.1 For comparative purposes, please reproduce the same figure using Actuals for F2009 to F2019.

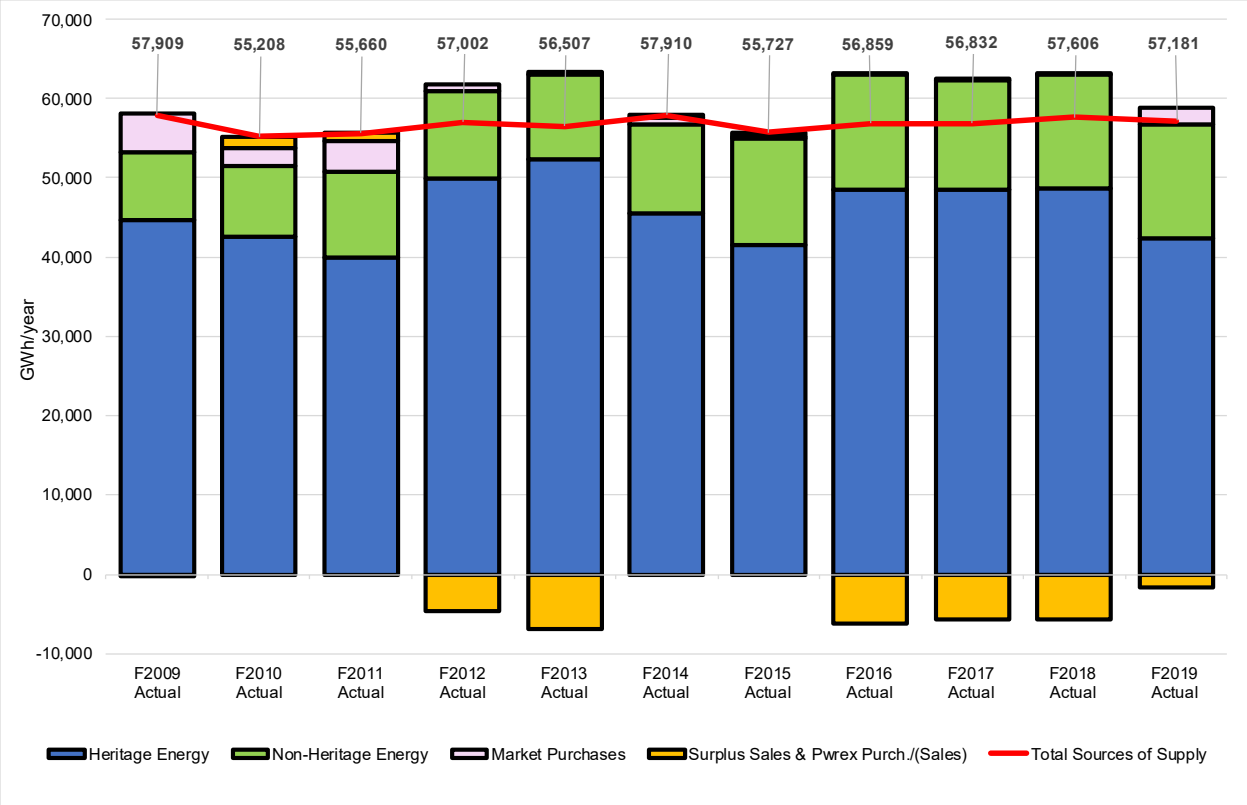
7.2 For comparative purposes, please reproduce the same figure to reflect the variance between RRA and Actual volumes for F2009 to F2019.

**Response:**

7.1

Please see Figure 7-1, reproduced Figure E-1, Source of Supply Actuals for F2009 to F2019.

**Figure 7-1: Source of Supply Actuals F2009-F2019[30]**

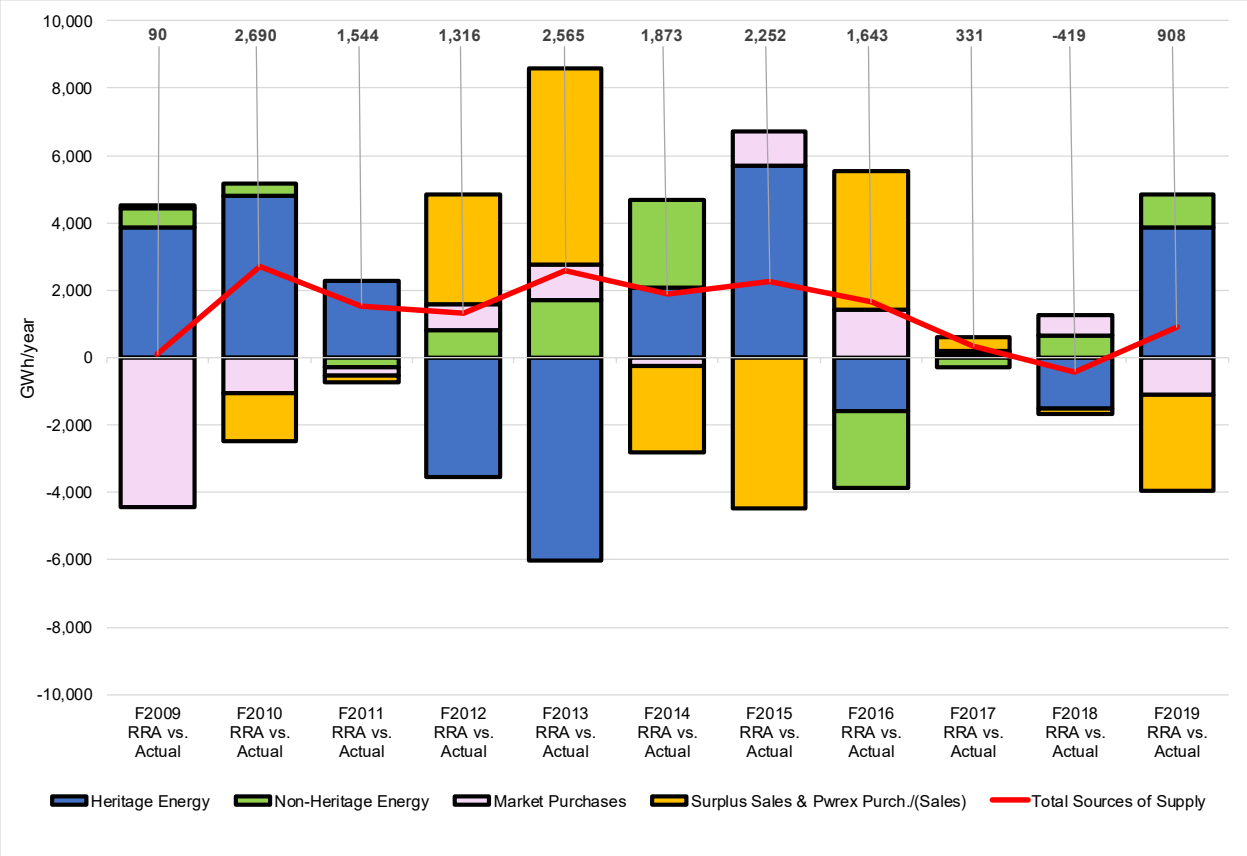



[30] Prepared based on information available from Schedule 4.0 of Appendix A in the BC Hydro's F2017-F2019 RRA (Exhibit B-1) and Evidentiary Update to F2020-F2021 RRA (Exhibit B-19).

7.2

Please see Figure 7-2 and Table 7-1 that present variances between RRA and Actual volumes for F2009 to F2019.

**Figure 7-2: Source of Supply F2009-F2019, variances between RRA and Actual volumes[31]**




Note: A substantial part of the variance is expected to be from water flow variation, which is typical for a hydraulic utility.

[31] Prepared based on information available from Schedule 4.0 of Appendix A in the BC Hydro's F2017-F2019 RRA (Exhibit B-1) and Evidentiary Update to F2020-F2021 RRA (Exhibit B-19).

## Table 7-1: Source of Supply F2009-F2021, RRA and Actual volumes (GWh)[32]

| | F2009 | | | F2010 | | | F2011 | | | F2012 | | | F2013 | | | F2014 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | RRA | Actual | Variance | RRA | Actual | Variance | RRA | Actual | Variance | RRA | Actual | Variance | RRA | Actual | Variance | RRA | Actual | Variance |
| **Heritage Energy** | | | | | | | | | | | | | | | | | | |
| Water Rentals | 48,274 | 43,812 | 4,462 | 46,817 | 43,208 | 3,609 | 41,677 | 39,303 | 2,375 | 46,260 | 49,829 | -3,569 | 46,175 | 52,115 | -5,940 | 47,517 | 45,328 | 2,189 |
| Natural Gas for Thermal Generation | 272 | 312 | -40 | 260 | 400 | -141 | 329 | 251 | 79 | 334 | 143 | 191 | 517 | 122 | 395 | 627 | 268 | 359 |
| Exchange Net | -12 | 536 | -548 | 224 | -1,092 | 1,316 | 177 | 372 | -195 | -211 | -45 | -166 | -447 | 28 | -475 | -572 | -103 | -469 |
| **Subtotal** | **48,533** | **44,660** | **3,873** | **47,301** | **42,516** | **4,785** | **42,184** | **39,925** | **2,258** | **46,383** | **49,927** | **-3,544** | **46,245** | **52,265** | **-6,020** | **47,572** | **45,493** | **2,079** |
| **Non-Heritage Energy** | | | | | | | | | | | | | | | | | | |
| IPPs and Long-Term Commitments | 8,950 | 8,374 | 576 | 9,277 | 8,893 | 384 | 10,504 | 10,805 | -301 | 11,618 | 10,827 | 791 | 12,367 | 10,673 | 1,694 | 13,606 | 11,025 | 2,581 |
| Non-Integrated Area | 112 | 116 | -4 | 115 | 113 | 2 | 116 | 114 | 2 | 120 | 111 | 9 | 126 | 113 | 13 | 132 | 117 | 15 |
| **Subtotal** | **9,062** | **8,490** | **572** | **9,392** | **9,006** | **386** | **10,620** | **10,919** | **-299** | **11,738** | **10,938** | **800** | **12,492** | **10,786** | **1,706** | **13,738** | **11,142** | **2,596** |
| **Market Energy** | | | | | | | | | | | | | | | | | | |
| Market Electricity Purchases | 588 | 5,020 | -4,432 | 1,091 | 2,161 | -1,070 | 3,553 | 3,791 | -238 | 1,610 | 840 | 770 | 1,419 | 359 | 1,060 | 660 | 918 | -258 |
| Surplus Sales | -24 | -196 | 172 | -99 | 0 | -99 | 0 | -53 | 53 | -109 | -710 | 601 | -874 | -6,020 | 5,146 | -1,496 | -1,008 | -488 |
| Net Purchases (Sales) from Powerex | -161 | -65 | -96 | 213 | 1,525 | -1,312 | 847 | 1,077 | -230 | -1,304 | -3,993 | 2,689 | -210 | -883 | 673 | -691 | 1,365 | -2,056 |
| **Subtotal** | **404** | **4,759** | **-4,355** | **1,205** | **3,686** | **-2,481** | **4,400** | **4,816** | **-416** | **197** | **-3,863** | **4,060** | **335** | **-6,544** | **6,879** | **-1,527** | **1,275** | **-2,802** |
| **Total Sources of Supply** | **57,999** | **57,909** | **90** | **57,898** | **55,208** | **2,690** | **57,204** | **55,660** | **1,544** | **58,318** | **57,002** | **1,316** | **59,072** | **56,507** | **2,565** | **59,783** | **57,910** | **1,873** |

| | F2015 | | | F2016 | | | F2017 | | | F2018 | | | F2019 | | | Test Years | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | RRA | Actual | Variance | RRA | Actual | Variance | RRA | Actual | Variance | RRA | Actual | Variance | RRA | Actual | Variance | F2020 | F2021 |
| **Heritage Energy** | | | | | | | | | | | | | | | | | |
| Water Rentals | 47,478 | 41,230 | 6,248 | 46,906 | 49,352 | -2,446 | 48,560 | 48,736 | -176 | 47,219 | 47,926 | -707 | 46,368 | 42,341 | 4,027 | 39,368 | 44,522 |
| Natural Gas for Thermal Generation | 290 | 213 | 77 | 301 | 215 | 86 | 224 | 74 | 151 | 232 | 91 | 141 | 234 | 191 | 43 | 181 | 195 |
| Exchange Net | -530 | 88 | -618 | -204 | -976 | 772 | -115 | -253 | 138 | -323 | 599 | -923 | -354 | -155 | -200 | -473 | -250 |
| **Subtotal** | **47,238** | **41,531** | **5,707** | **47,003** | **48,591** | **-1,588** | **48,669** | **48,557** | **112** | **47,128** | **48,616** | **-1,488** | **46,248** | **42,377** | **3,871** | **39,075** | **44,467** |
| **Non-Heritage Energy** | | | | | | | | | | | | | | | | | |
| IPPs and Long-Term Commitments | 13,339 | 13,377 | -38 | 12,002 | 14,319 | -2,317 | 13,375 | 13,644 | -269 | 15,002 | 14,354 | 648 | 15,199 | 14,248 | 951 | 13,949 | 15,238 |
| Non-Integrated Area | 133 | 115 | 18 | 135 | 111 | 24 | 117 | 118 | -0 | 119 | 115 | 5 | 120 | 103 | 17 | 118 | 120 |
| **Subtotal** | **13,472** | **13,492** | **-20** | **12,137** | **14,430** | **-2,293** | **13,493** | **13,762** | **-270** | **15,121** | **14,469** | **653** | **15,320** | **14,351** | **968** | **14,067** | **15,358** |
| **Market Energy** | | | | | | | | | | | | | | | | | |
| Market Electricity Purchases | 1,224 | 207 | 1,017 | 1,553 | 122 | 1,431 | 230 | 131 | 98 | 747 | 150 | 597 | 934 | 2,035 | -1,101 | 5,104 | 1,326 |
| Surplus Sales | -3,756 | -15 | -3,741 | -2,446 | -6,277 | 3,831 | -4,962 | -5,756 | 794 | -5,556 | -5,072 | -484 | -4,517 | -2,230 | -2,287 | -84 | -2,065 |
| Net Purchases (Sales) from Powerex | -199 | 512 | -711 | 255 | -6 | 261 | -267 | 138 | -404 | -253 | -557 | 304 | 105 | 647 | -542 | 468 | -279 |
| **Subtotal** | **-2,731** | **704** | **-3,435** | **-638** | **-6,162** | **5,524** | **-5,000** | **-5,488** | **488** | **-5,062** | **-5,479** | **417** | **-3,478** | **452** | **-3,930** | **5,488** | **-1,018** |
| **Total Sources of Supply** | **57,979** | **55,727** | **2,252** | **58,502** | **56,859** | **1,643** | **57,162** | **56,832** | **331** | **57,187** | **57,606** | **-419** | **58,089** | **57,181** | **908** | **58,630** | **58,806** |

[32] Prepared based on information available from Schedule 4.0 of Appendix A in the BC Hydro's F2017-F2019 RRA (Exhibit B-1) and Evidentiary Update to F2020-F2021 RRA (Exhibit B-19).

**1.0 Reference: Exhibit C-11-11, Intervener Evidence filed by the Association of Major Power Customers of BC (AMPC), discussing the impact on industrial rate competitiveness of BC Hydro acquiring electricity from Independent Power Producers.**

Section 1.1, Conclusions and Recommendations, states (underlining added):

> *"9. There are costs included in BC Hydro's Application that contribute materially to the uncompetitiveness of rates, but are understood to be beyond the regulatory jurisdiction of the BCUC at this time, due to directions from Government. It is important to have such costs clearly identified even if the BCUC cannot direct associated changes (Section 4.6)."*
>
> *10. With a return to full regulation, the BCUC must ensure future rate reviews consider and test the prudence and least cost nature of all costs that continue to be included in revenue requirement (even costs committed in previous periods, which have to date not been properly tested or adjusted in rates). A number of costs are now explicitly acknowledged by either the BC Government (Independent Power Producer costs, Water Rentals) or the BCUC (Capital projects which merited an ex post factor review to determine prudency) as not meeting the test for least cost utility planning or full and transparent regulatory review. (Section 4.6).*

Section 2.0, paragraphs 2 and 3 state (underlining added):

*As a general principle, prices for electricity throughout Canada are set based on one of the following three basic approaches:*

> *1) <u>reliance on market forces and free and fair competition</u> for components of service that can be provided on this basis, such as generation …or*
>
> *2) by <u>government, based on political considerations</u>, such as in Quebec for bulk power, Nunavut, <u>and British Columbia from 2013 to the most recent Government policy</u> to start reverting back to BCUC oversight; or*
>
> *3) based on regulated cost of service approaches …"*

*BC Hydro's <u>RRA for F2020-F2021 is an amalgamation between the latter two approaches</u>, where Government has set direction for some requirements for rate setting, with the BCUC exerting regulatory oversight for some cost categories making up BC Hydro's revenue requirement."*

BC Hydro stated in its Report on the Clean Power Call RFP[1] that:

*"The price to be paid for this electricity met BC Hydro's expectations based on comparisons to other BC Hydro processes and similar processes undertaken by other jurisdictions, and to 2008 LTAP projections. BC Hydro's Clean Power Call process has resulted in the acquisition of costeffective clean, renewable electricity for BC Hydro's ratepayers."*

BC Hydro stated in its Report on the Bioenergy Phase 2 Call RFP[2] that:

*"The cost-effectiveness is also demonstrated by comparing the RFP results to other BC Hydro calls. … Furthermore, the weighted-average Average Firm Energy Price for the Bioenergy Phase 2 RFP is lower than that for the Clean Power Call … The Bioenergy Phase 2 RFP awards are also comparable to recent Hydro-Quebec awards for biomass and wind projects."*

1.1 Please advise why the above competitively awarded EPAs are not included in the basic approach "1) reliance on market forces and free and fair competition for components of service that can be provided on this basis, such as generation…"?

1.2 Please identify where the BC Government has explicitly acknowledged Independent Power Producer costs "as not meeting the test for least cost utility planning or full and transparent regulatory review."

1.3 Please advise why above competitively awarded EPAs do not "meet the test for least cost utility planning or full and transparent regulatory review."

**Response:**

1.1 to 1.3

These questions reference Section 4.6 of the InterGroup evidence. Section 4.6 references electricity procured from Independent Power Producers (IPPs) and conclusions from the report commissioned by the BC Government and published by the Minister of Energy, Mines and Petroleum Resources (the "Zapped Report"). The Zapped Report reviewed BC Hydro power

[1] BC Hydro 2010 Clean Power Call: Report on the RFP Process, page 2.
[2] BC Hydro 2012 Biomass Energy 2: Report on the RFP Process, page 3.

planning since the 2002 Energy Plan specifically as regards purchases from IPPs. It made the following findings:[3]

> "This report draws three conclusions:
>
> - BC Hydro bought too much energy and energy with the wrong profile;
> - BC Hydro paid too much for the energy it bought, and
> - BC Hydro undertook these actions at the direction of Government."

Please see the Zapped Report for a review of the extent of Government direction, BCUC regulatory reviews and other factors relevant to adverse cost impacts from historic IPP power purchases. InterGroup understands that the BCUC regulatory review of IPP power purchases by BC Hydro became limited after the initial years of this period.

[3] Zapped: A Review of BC Hydro's Purchase of Power from Independent Power Producers conducted for the Minister of Energy, Mines and Petroleum Resources, by Ken Davidson, February 2019; page 1.

**2.0 Reference: Exhibit C-11-11, Intervener Evidence filed by the AMPC, discussing the impact on industrial rate competitiveness of BC Hydro acquiring electricity from Independent Power Producers.**

Section 3.2, BC GOVERNMENT COMPREHENSIVE REVIEW OF BC HYDRO, states (underlining added):

*"BC Hydro's Original RRA was filed following the February 2019 Ministry of Energy, Mines and Petroleum Resources' Comprehensive Review of BC Hydro: Phase 1 Final Report.*

*In addition, a concurrent review was undertaken by Ken Davidson as part of the review relating to purchase of power from IPPs, which was also made available in February 2019.[4]"*

*Phase 1 of the Comprehensive Review primarily addresses three key areas:[15]*

1. *Enhancing the BCUC oversight of BC Hydro.*
2. *Establishing new electricity rates.*
3. *Short-term actions to address power acquisition costs (Electricity Purchase Agreements or "EPAs")*

*For short-term control of EPA costs, or the form of agreement by which BC Hydro purchases power from Independent Power Producers (IPPs), the Comprehensive Review offers little relief. The only actions tie to limiting future purchases under the Standing Offer Program and limiting renewals under the strategically important biomass EPAs (which are specifically cited to be important to "recognizing the socio-economic importance of forest sector facilities" but also function to improve competitiveness and as a result support BC Hydro's own financial interests in respect of domestic loads). There has been no relief or pathway to solutions proposed to address the significant problems posed by existing IPP arrangements.*

2.1 Why are biomass EPAs singled out to be strategically important? Why not other IPPs, including Rio Tinto Alcan, Municipal Solid Waste, other co-gens, or independent IPPs?

2.2 Why are IPPs that provide grid support not strategically important?

2.3 Why are IPPs that involve First Nations and provide material benefits for First Nations not strategically important?

[4] Zapped: A Review of BC Hydro's Purchase of Power from Independent Power Producers conducted for the Minister of Energy, Mines and Petroleum Resources, by Ken Davidson, February 2019

2.4 What are the "significant problems posed by existing IPP arrangements"?

2.5 Given what BC Hydro stated in its Report on the Clean Power Call RFP, and in its Report on the Bioenergy Phase 2 Call RFP, does AMPC not believe that these IPP EPAs were competitive at the time they were awarded?

**Response:**

2.1

Biomass EPAs are described as "strategically important" for the reasons provided in the quote contained within this question's preamble, namely BC Hydro's statement of "recognizing the socio-economic importance of forest sector facilities" and InterGroup's understanding that these EPAs "also function to improve competitiveness and as a result support BC Hydro's own financial interests in respect of domestic loads".

InterGroup did not single out biomass – that comment comes from the distinction noted in the BC Government Comprehensive Review, that biomass sources can have more compelling considerations than simply energy supply. It is possible that other IPP supply sources share some of the same characteristics.

2.2 to 2.4

Please see AMPC's response to CEABC IRs 1.1 to 1.3. InterGroup's evidence regarding the financial effects of existing IPP arrangements within BC Hydro's Application has relied on the recent BC Government "Zapped Report." Accordingly, questions related to BC Hydro and Government assessments in the Phase 1 Comprehensive Report as to the strategic importance of different IPPs should be addressed to BC Hydro.

2.5

The views of AMPC's predecessor (JIESC) in BC Hydro's 2008 LTAP were that IPPs at that time were not competitive. Counsel for JIESC stated as follows in his opening remarks in BC Hydro's 2008 LTAP proceeding:

> Transcript of Proceedings at Hearing, page 182-3:
>
> "The JIESC is concerned that unrequired excess power purchased from IPPs will need to be sold in the export market at a substantial loss from the contracted prices and form a significant long-term burden on B.C. Hydro's domestic customers, that they can ill afford. I can say from personal experience that buying high and selling low is simply not a good long-term philosophy."

**3.0 Reference: Exhibit C-11-11, Intervener Evidence filed by the AMPC, discussing the impact on industrial rate competitiveness of BC Hydro acquiring electricity from Independent Power Producers.**

Section 4.0, BACKGROUND AND CONTEXT, paragraphs 2 and 3 state (underlining added):

*In a sense, many of the present issues arise from a material change in direction for BC Hydro as a result of the Government's 2002 BC Energy Plan. As noted in the Comprehensive Review (Section 4.2.2), this period reflected a material change in direction for the policy towards IPPs. The policy framework was also applied inconsistently and excessively between 2002 and 2012, the overall outcome was to significant ratepayer detriment.*

*Subsequent government reviews and policies exacerbated the effects of the 2002 Energy Plan, such as the 2007 Energy Plan which greatly increased the magnitude of IPP purchases required.*

In Section 4.6, IPP AND OTHER COST ISSUES IMPACTED BY GOVERNMENT, paragraphs 1 to 3, AMPC quotes from a 3rd party report, called Zapped[5] and states (underlining added):

*"Concurrent with the Comprehensive Review, the BC Government commissioned a review of BC Hydro power planning since the 2002 Energy Plan, including periods of significant and ill-advised Government direction. The report[6] was published by the Minster of Energy, Mines and Petroleum Resources.*

*The review that was commissioned was very clear in its findings, quoted as follows:*

> *This report draws three conclusions:*
>
> - *BC Hydro bought too much energy and energy with the wrong profile;*
> - *BC Hydro paid too much for the energy it bought, and*
> - *BC Hydro undertook these actions at the direction of Government.*

*The cost pressures arising from these Government directed actions are evident in the rate pressures and competitiveness issues exhibited in BC from excessive sourcing of*

[5] Zapped: A Review of BC Hydro's Purchase of Power from Independent Power Producers conducted for the Minister of Energy, Mines and Petroleum Resources, by Ken Davidson, February 2019
[6] Zapped: A Review of BC Hydro's Purchase of Power from Independent Power Producers conducted for the Minister of Energy, Mines and Petroleum Resources, by Ken Davidson, February 2019

*third-party IPP energy (for example, energy supplied by parties who are not otherwise BC Hydro industrial customers, e.g., unlike biomass which supports industry and BC Hydro loads)."*

*Zapped*'s Executive Summary and Conclusion both repeat the following allegation:

*"Government directed BC Hydro to purchase 8,500 GWh/year of Firm energy BC Hydro did not need. This direction of BC Hydro's actions is manifest in the Response EPAs … The Response EPAs cost ratepayers an Estimated $16.2 billion over 20 years, the estimated period during which BC Hydro will likely not need the energy Government told it to buy."*[7]

*Zapped* arrives at the $16.2 billion "Estimate" using the following formula:

9,500 GWh/year x $85/MWh x 20 years = $16.2 billion

The 9,500 GWh/year amount is the total energy contracted under all the EPAs (Electricity Purchase Agreements) signed since 2007 (the "Response EPAs"). The 8,500 GWh/year amount is the amount that *Zapped* alleges the previous government directed BC Hydro buy from IPPs since 2007 that was not needed. *Zapped* alleges that the government directed BC Hydro to buy 8,500 GWh in 2007 which has now resulted in BC Hydro buying 9,500 GWh.

*Zapped* states that *"this report expects the annual impact of the over-buy will be felt for some 20 years."*[8] *Zapped* starts its tally of the 9,500 GWh/yr of overbought Response EPAs[9] in 2009.[10] *Zapped*'s $16.2 billion estimate is based on the full amount of the overbought energy being surplus to domestic needs and therefore being sold to the export market at Mid-C. Zapped estimates the total surplus to be 190,000 GWh (9,500 GWh x 20 years).

Over the 20 years *Zapped* overestimated the surplus by 166,545 GWh compared to BC Hydro historical records[11] and forecast[12][13]. The table below (prepared by CEABC from

[7] *Zapped* pages 1 and 72.
[8] *Zapped* page 48.
[9] Response EPAs are the EPAs that BC Hydro awarded to IPPs since 2007. Zapped states that they total 9,500 GWh/year
[10] *Zapped* Page 53, starting with the Dokie Wind 2009 EPA and adding the subsequent EPAs for projects listed in red ink.
[11] The annual volumes in this calculation are taken from adding the hourly volumes shown in the columns titled "US Tie Lines" and "AB Tielines" in the spreadsheets titled "BC Hydro Actual Interchange" on the BC Hydro website: https://www.bchydro.com/energy-in-bc/operations/transmission/transmission-system/actual-flow-data/historical-data.html in the section titled "Net Actual Flow".
[12] BC Hydro Application to the BCUC dated October 5, 2018, Appendix B, Table 3-8; revised F2017-2019 Revenue Requirement Application, Load Resource Balance After Planned Resources - Energy

those records and forecasts), shows that *Zapped* overestimated the surplus by a factor of 8 times too much. Or the corollary, BC Hydro's amounts are only 12% of the *Zapped* estimate.

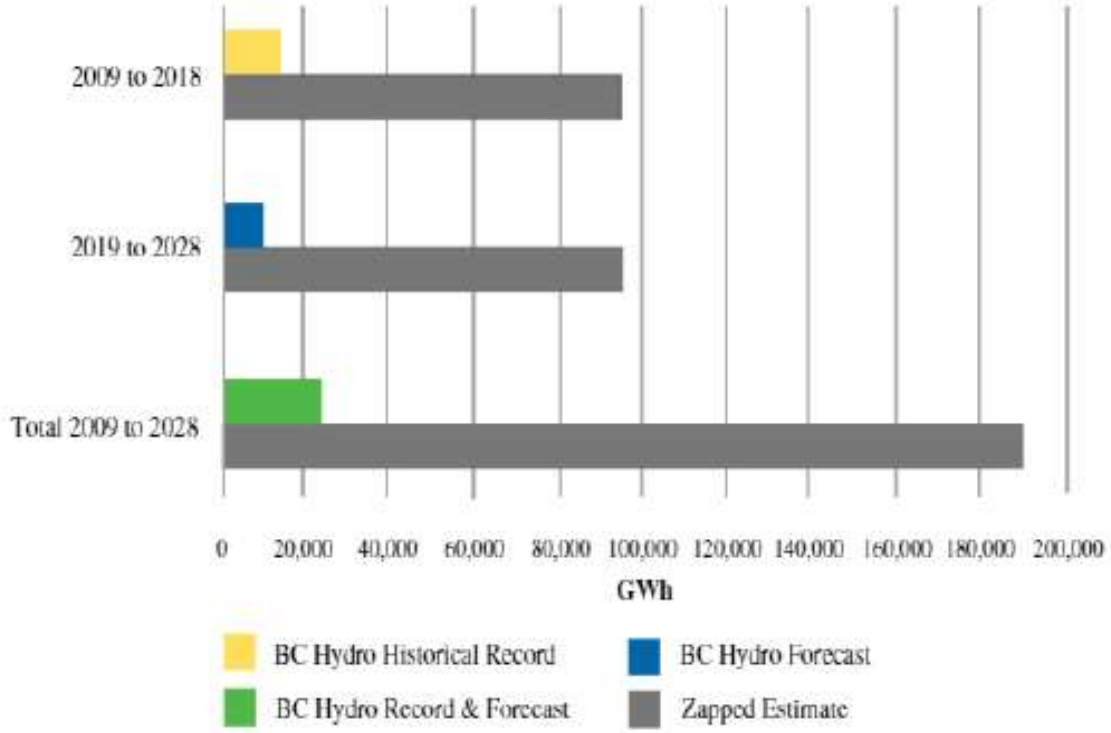
***Table: Comparing Zapped's IPP Surplus vs. BC Hydro Record or Forecast over 20 years***

| Surplus Comparison | Zapped Estimate | BC Hydro Historical Record or RRA Forecast | Overestimate Amount | Overestimate Factor (# of times over BC Hydro amount) | Percent BC Hydro vs Zapped |
|---|---|---|---|---|---|
| Period | GWh | GWh | GWh | | |
| 2009 - 2018 | 95,000 | 15,531 | 79,469 | 6.1 | 16% |
| 2019 - 2028 | 95,000 | 7,925 | 87,075 | 12.0 | 8% |
| Total 2009 - 2028 | 190,000 | 23,456 | 166,544 | 8.1 | 12% |

The figure below shows Zapped's estimated surpluses vs. BC Hydro records and forecast (a graphic representation of the above table data).

[13] The energy generated by Site C is deducted in this determination because it was built by BC Hydro, not an IPP. And Site C was started after 98% of the Response EPAs (that are the subject of Zapped's "overbought" allegation) were signed.

***Figure: Comparing Zapped Estimate of Surplus due to IPP Over-purchasing to BC Hydro Historical Records and Forecast from 2009 - 2028(GWh)***




3.1 In light of BC Hydro historical records and forecast showing that a surplus that is 1/8th of the surplus estimated by Zapped, does AMPC agree with the Zapped claim that BC Hydro bought too much IPP power?

3.2 Please advise on how *"the policy framework was applied inconsistently and excessively between 2002 and 2012 with the overall outcome a significant ratepayer detriment."*

**Response:**

3.1

Please see AMPC's response to CEABC IRs 1.1 to 1.3 concerning InterGroup's reliance on the Zapped Report and response to CEABC IR 2.5 concerning AMPC's 2008 concern that the then-proposed IPP contracting practices would lead to excess power sold in the export market at a substantial loss from contracted prices, and a long-term burden to domestic customers.

3.2

The Zapped Report highlights that the policy framework was applied to cause excessive purchases, in particular related to the change imposed by the 2007 Energy Plan. Prior to this time, the scale of purchases was far more modest than in response to the targets set out in the 2007 Energy Plan. The definitions of “surplus” and “insurance” in the 2007 Energy Plan were inconsistent with past approaches and normal utility planning for BC Hydro and have been concluded to be ill-advised.

**4.0 Reference: Exhibit C-11-11, Intervener Evidence filed by the AMPC, discussing the impact on industrial rate competitiveness of BC Hydro acquiring electricity from Independent Power Producers.**

In Section 4.6, IPP AND OTHER COST ISSUES IMPACTED BY GOVERNMENT, paragraphs 1 to 3, AMPC quotes from a 3rd party report, called Zapped and states (underline added):

*"Concurrent with the Comprehensive Review, the BC Government commissioned a review of BC Hydro power planning since the 2002 Energy Plan, including periods of significant and ill-advised Government direction. The report was published by the Minster of Energy, Mines and Petroleum Resources.*

*The review that was commissioned was very clear in its findings, quoted as follows:*

*This report draws three conclusions:*

- *BC Hydro bought too much energy and energy with the wrong profile;*
- *BC Hydro paid too much for the energy it bought, and*
- *BC Hydro undertook these actions at the direction of Government.*

*The cost pressures arising from these Government directed actions are evident in the rate pressures and competitiveness issues exhibited in BC from excessive sourcing of third-party IPP energy (for example, energy supplied by parties who are not otherwise BC Hydro industrial customers, e.g., unlike biomass which supports industry and BC Hydro loads)."*

*Zapped*'s Executive Summary and Conclusion both repeat the following allegation:

*"Government directed BC Hydro to purchase 8,500 GWh/year of Firm energy BC Hydro did not need. This direction of BC Hydro's actions is manifest in the Response EPAs … The Response EPAs cost ratepayers an Estimated $16.2 billion over 20 years, the estimated period during which BC Hydro will likely not need the energy Government told it to buy."*[14]

*Zapped* arrives at the $16.2 billion *"Estimate"* using the following formula:

<u>9,500 GWh/year</u> x $85/MWh x 20 years = $16.2 billion

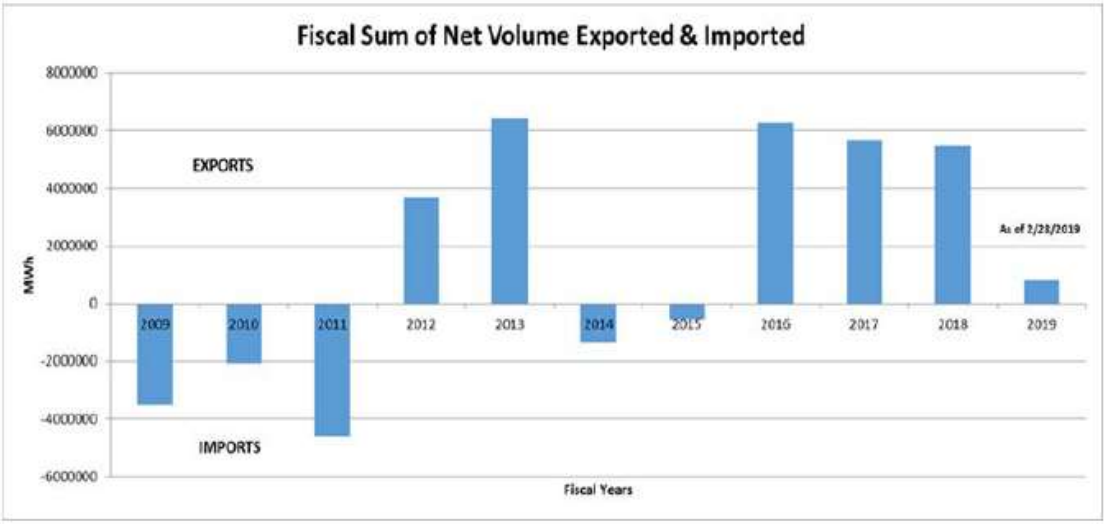
[14] *Zapped* pages 1 and 72.

*Zapped* states that *"this report expects the annual impact of the over-buy will be felt for some 20 years."*[15] *Zapped* starts its tally of the 9,500 GWh/yr of overbought Response EPAs[16] in 2009.[17]

*Zapped* estimates the total surplus for the last 10 years to be 90,000 GWh (9,500 GWh x 10 years).

The total of the actual net exported surplus over the last10 years has been 15,531 GWh according to the following graph produced by CEABC from BC Hydro data.[18]

***Figure: BC Net Energy Export & Import Volumes - Fiscal 2009 to Fiscal 2018 per BC Hydro***




As compared to net exports it would appear Zapped's surplus estimate was 79,469 GWh too high or 6 times higher than BC Hydro's records (95,000/15,531).

Over the last 10 years that works out to be an average annual surplus of 1,553 GWh.

BC Hydro has stated that, as a result of variable water conditions, the energy capability of the Heritage Resources can vary up to 14,000 GWh each year – between a very wet

[15] *Zapped* page 48.
[16] Response EPAs are the EPAs that BC Hydro awarded to IPPs since 2007. Zapped states that they total 9,500 GWh/year
[17] *Zapped* Page 53, starting with the Dokie Wind 2009 EPA and adding the subsequent EPAs for projects listed in red ink.
[18] The annual volumes on the graph are from adding the hourly volumes shown in the columns titled "US Tie Lines" and "AB Tielines" in the spreadsheets titled "BC Hydro Actual Interchange" on the BC Hydro website: https://www.bchydro.com/energy-in-bc/operations/transmission/transmission-system/actual-flow-data/historical-data.html in the section titled "Net Actual Flow". The years on the graph correspond to BC Hydro's Fiscal Year.

year and a very dry year[19]. The 1,553 GWh surplus is only 11% of the total potential range due to water variability.

4.1 In light of BC Hydro historical records showing that the actual surplus was 1/6th of the surplus forecast by Zapped and that the average surplus amount of 1,553 GWh is only 11% of the potential variation of annual hydro generation, does AMPC agree with the Zapped claim that BC Hydro bought too much IPP power?

**Response:**

4.1

Please see AMPC's response to CEABC IR 3.1 concerning InterGroup's reliance on the Zapped Report and on AMPC's 2008 concerns about IPP procurement.

[19] Section 4.1.1 Impact of Variability of Water Flows in BC Hydro's Transmission Service Market Reference-Priced Rates Application; "BC Hydro notes that there can be significant variability in system water inflows, in the range of +/- 7,000 GWh/yr." [Where does this quote come from?]

**5.0 Reference: Exhibit C-11-11, Intervener Evidence filed by the AMPC, discussing the impact on industrial rate competitiveness of BC Hydro acquiring electricity from Independent Power Producers.**

In Section 4.6, IPP AND OTHER COST ISSUES IMPACTED BY GOVERNMENT, AMPC quotes from a 3rd party report, called Zapped and states (underlining added):

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*Zapped*'s Executive Summary and Conclusion both repeat the following allegation:

*"Government directed BC Hydro to purchase 8,500 GWh/year of Firm energy BC Hydro did not need. This direction of BC Hydro's actions is manifest in the Response EPAs … The Response EPAs cost ratepayers an Estimated $16.2 billion over 20 years, the estimated period during which BC Hydro will likely not need the energy Government told it to buy."*[20]

*Zapped* arrives at the $16.2 billion *"Estimate"* using the following formula:

9,500 GWh/year x $85/MWh x 20 years = $16.2 billion

*Zapped* alleges that BC Hydro paid $85/MWh too much for the 9,500 GWh of energy it acquired through the EPAs signed after 2007. It reached the $85 premium using the following formula:

$85/MWh = $110/MWh - $25/MWh

*Zapped* states that the:

- *"… average cost of 9,500 GWh of blended energy acquired in 2009 is assumed to be $110/MWh."*

[20] *Zapped* pages 1 and 72.

*Zapped asserts that "energy has only one price and that is the price it can be bought or sold at in the market. In the case of BC Hydro, the market value of all energy is the Mid-C rate."*

In 2006, two senior executives from BC Hydro gave the following testimony[21] to the BCUC (underlining added):

- *"… we've made an assessment that we feel that's too heavy a reliance on spot market. And so the actions we are taking in this LTAP are moving us away from a reliance towards more energy security …"*
- *"We fundamentally believe that having 18% of our reliance on the spot market … is accepting too much volatility, and that replacing the energy of that plant with longer-term products that have less volatility is more cost-effective overall."*
- *"We are moving away from a reliance on spot market. So that's why we have proposed these two future calls going forward … We've set those call volumes based on what we feel we need to bring on to close this supply gap that we've got."*

BC Hydro stated in its Report on the Clean Power Call RFP[22] that:

> *"The price to be paid for this electricity met BC Hydro's expectations based on comparisons to other BC Hydro processes and similar processes undertaken by other jurisdictions, and to 2008 LTAP projections. BC Hydro's Clean Power Call process has resulted in the acquisition of costeffective clean, renewable electricity for BC Hydro's ratepayers."*

BC Hydro stated in its Report on the Bioenergy Phase 2 Call RFP[23] that:

> *"The cost-effectiveness is also demonstrated by comparing the RFP results to other BC Hydro calls. … Furthermore, the weighted-average Average Firm Energy Price for the Bioenergy Phase 2 RFP is lower than that for the Clean Power Call … The Bioenergy Phase 2 RFP awards are also comparable to recent Hydro-Quebec awards for biomass and wind projects."*

The current Government approved the continuation of Site C based on BC Hydro stating that its price would be $65/MWh.[24] That is over twice the price of Mid-C, which

[21] Transcripts from the BC Hydro Executive VP-Operations and the BC Hydro Executive VP –Customer Care and Conservation at the BCUC review of the BC Hydro 2006 Integrated Electricity Plan and Long Term Acquisition Plan, Volume 9, pages 1125 – 1127.
[22] BC Hydro 2010 Clean Power Call: Report on the RFP Process. Page 2.
[23] BC Hydro 2012 Biomass Energy 2: Report on the RFP Process. Page 3.

has averaged around $30/MWh for a considerable period of time. The CEAA/BCEAA[25] Joint Review Panel did not compare the price of Site C to Mid-C in its 2014 Assessment. Nor did the BCUC consider Mid-C in its 2017 Site C Inquiry.

5.1 In light of BC Hydro executives' recommendation to reduce reliance on Mid-C imports and increase reliance on long-term EPAs, the Joint Review Panel and the BCUC Site C Inquiry did not use Mid-C as a comparator for building Site C. Does AMPC agree with Zapped's claim that "the value of all energy is Mid-C" and therefore that BC Hydro paid too much for IPP energy at the time the electricity purchase agreements were entered into?

**Response:**

5.1

Please see AMPC's response to CEABC IR 2.5 concerning AMPC's 2008 concerns about IPP over-procurement, to the effect that there would be surplus IPP energy and such energy would be sold into Mid-C at a loss.

[24] BC Hydro based that $65/MWh price on an estimated capex of $8.9 billion. The government approved a budget of $10.7 billion.
[25] Canadian Environmental Assessment Act and BC Environmental Assessment Act

**6.0 Reference: Exhibit C-11-11, Intervener Evidence filed by the Association of Major Power Customers of BC (AMPC), discussing the impact on industrial rate competitiveness of BC Hydro acquiring electricity from Independent Power Producers.**

Section 4.6, IPP AND OTHER COST ISSUES IMPACTED BY GOVERNMENT, AMPC quotes from a 3rd party report, called Zapped and states (underlining added):

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*Zapped*'s Executive Summary and Conclusion both repeat the following allegation:

*"Government directed BC Hydro to purchase 8,500 GWh/year of Firm energy BC Hydro did not need. This direction of BC Hydro's actions is manifest in the Response EPAs … The Response EPAs cost ratepayers an Estimated $16.2 billion over 20 years, the estimated period during which BC Hydro will likely not need the energy Government told it to buy."*[26]

*Zapped* links the related amounts of 9,500 GWh/year and 8,500 GWh/year as follows:

*"The Response EPAs represent approximately 9,500 GWh of additional contracted energy. These EPAs act as a proxy for the impact. Of note, total energy contracted under the Response EPAs includes both Firm and non-Firm energy, whereas the policy directive demanded BC Hydro deliver 8,500 GWh in Firm energy. BC Hydro was trying to buy 8,500 GWh of Firm energy, but likely managed to buy only 9,500 GWh of blended energy."*

*Zapped* states:

- *"Given Government's direction and BC Hydro's intent to comply, the Estimate of the impact of the policy direction could be based on 8,500 GWh of incremental Firm energy."*
- *"… the 2007 Energy Plan and Special Direction #10 amounted to direct Government interference with the energy planning process at BC Hydro, with*

[26] *Zapped* pages 1 and 72.

*the intent to create the appearance of an energy shortfall. The resulting energy shortfall was then used to justify an expansion of the IPP portfolio and gave rise to the calls for power issued since 2007…"*[27]

- *"In Recommendation 19 of the 2007 Energy Plan Government directed that the province would achieve zero net greenhouse gas emissions from existing thermal generation plants by 2016. This was effectively a direction that BC Hydro must close Burrard Thermal by 2016."*
- *"After 2007, BC Hydro operated with the intent that it needed to buy 8,500 GWh of incremental Firm Energy."*

The following table summarizes the policy directions that Zapped claimed constituted government interference in BC Hydro's load forecasting and planning:

| Direction | Document and Date | Added Demand |
|---|---|---|
| | | *GWh/yr* |
| Eliminate market purchases | Special Direction #10 issued December, 2007 | 2,500 |
| Insurance | Special Direction #10 issued December, 2007 | 3,000 |
| Reduce use of Burrard | Recommendation #19 in 2007 Energy Plan | 3,000 |
| | **Total** | **8,500** |

*Zapped* claims that these three Government Directions *"amounted to direct Government interference with the energy planning process at BC Hydro with the intent to create the appearance of an energy shortfall."*

However, in 2006, two senior executives at BC Hydro gave the following testimony[28] to the BCUC (with underlining added):

- *"Right now we rely on spot market for about 18% of our domestic load, and we've made an assessment that we feel that's too heavy a reliance on spot market. And so the actions we are taking in this LTAP*[29] *are moving us away from a reliance towards more energy security …"*
- *"We fundamentally believe that having 18% of our reliance on the spot market, because we fundamentally have a plant that looks like it's producing energy but it really isn't. It's just having us purchase from the spot market, is accepting too*

[27] *Zapped* page 43.
[28] Transcripts from BC Hydro Executive VP-Operations and BC Hydro Executive VP –Customer Care and Conservation at the BCUC review of the BC Hydro 2006 Integrated Electricity Plan and Long Term Acquisition Plan, Volume 9, pages 1125 – 1127.
[29] BC Hydro's 2008 Long Term Electricity Plan.

> *much volatility, and that replacing the energy of that plant with longer-term products that have less volatility is more cost-effective overall."*[30]

BC was a net importer of energy for 6 of the 7 years from 2001 to 2007. That is based on the tables on the BC Hydro website that show the Net Actual Flows across the US Tie-lines.[31]

The 2007 Energy Plan pointed to the high and growing level of imports and added strong domestic load growth as the rationale for adding "insurance":

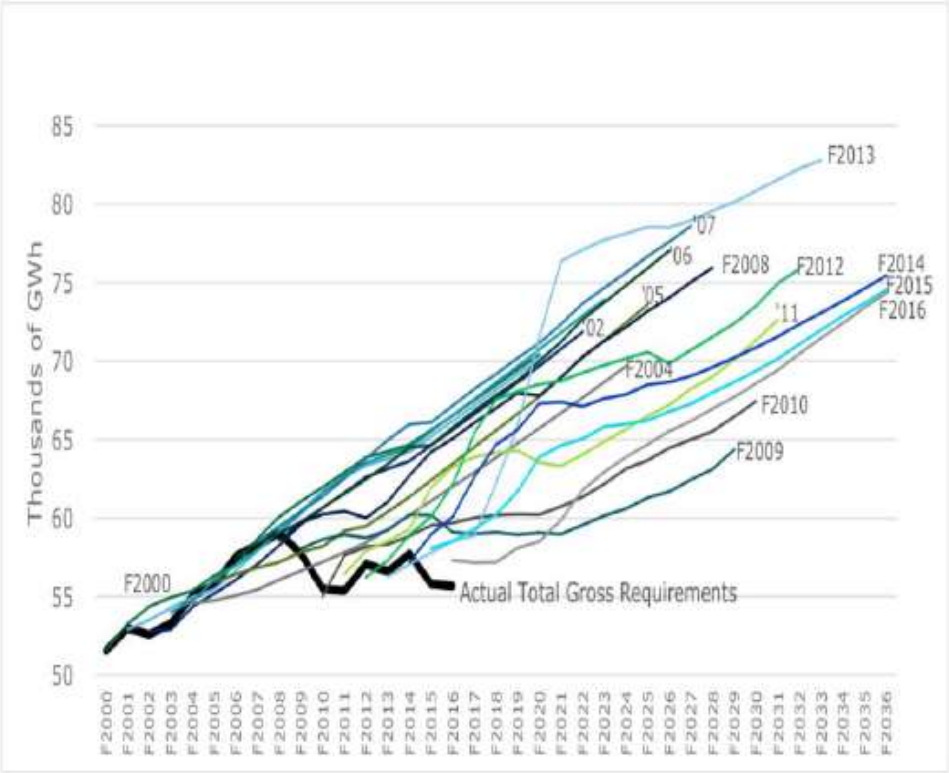
- *"BC Hydro must acquire an additional supply of "insurance power" beyond the projected increases in demand to minimize the risk and implications of having to rely on electricity imports."*
- *"BC Hydro estimates demand for electricity to grow by up to 45 per cent over the next 20 years."*

The graph[32] below compares 16 load forecasts from 2000 to 2016 made by BC Hydro as compared to the actual requirements. BC Hydro's 2007 and 2008 Load Forecasts are shown as thin black lines that consistently follow that strong growth rate increase from before 2007 to 2027.

[30] The energy crisis in California in 2000 - 2001 resulted from an apparent energy shortage as well as low water on the west coast. It caused very high electricity prices. In 2000 annual rates peaked at $200/MWh. [This footnote should be deleted. This is evidence and not a reference.]

[31] Calculated from totaling the annual volumes shown in the column titled "US Tie Lines" in the spreadsheets titled "BC Hydro Hourly Tieline Data" on the BC Hydro website: https://www.bchydro.com/energy-inbc/operations/transmission/transmission-system/actual-flow-data/historical-data.html in the section titled "Net Actual Flow".

[32] Site C – Alternative Resource Options and Load Forecast Assessment, submitted by Deloitte to the BC Utilities Commission. September 7, 2017 Figure 3: Total Gross Energy Requirement Forecast Models between 2000 and 2016 (with DSM)




6.1 In light of BC Hydro's BCUC testimony to the BCUC, the Net Actual Flows across the US Tie-lines from 2001 to 2007[33], and the projected increases up to 2008 and beyond, does AMPC agree with Zapped's claim that BC Hydro undertook these actions at the direction of Government?

**Response:**

6.1

The Zapped Report references special directions to the BCUC, the 2007 Energy Plan which imposed a new planning framework, and an item from the 2007 Energy Plan concerning net zero carbon emissions. AMPC is not in a position to add context regarding the extent of Ministry-BC Hydro direction or discussions underlying each of those steps and considers that doing so now would be irrelevant. A broader review of the details from the time period referenced in the Zapped Report is a matter for discussion with the author of the Zapped Report.

[33] Ibid.

**7.0 Reference: Exhibit C-11-11, Intervener Evidence filed by the Association of Major Power Customers of BC (AMPC), discussing the impact on industrial rate competitiveness of BC Hydro acquiring electricity from Independent Power Producers.**

Section 4.6, IPP AND OTHER COST ISSUES IMPACTED BY GOVERNMENT, paragraph 4 states:

*"The largest components of the Revenue Requirement are composed of the "Cost of Energy" supplied. This cost has grown materially in past years, in both total cost and in average unit cost. By far, the driving force behind this growth has been IPPs…."*

The following table displays the history of BC Hydro Revenue Requirement from F2007 to F2018, as extracted from the tables in Appendix A of the F2107-19 RRA and the F2020-21 RRA.[34]

[34] Exhibit B-13 in the F20-21 RRA proceeding, BC Hydro's response to CEABC IR 2.47.1

| GROSS & CURRENT BASIS | Summary History of BC Hydro Revenue Requirement from F2007 to F2018 | | | | | | | | | | | | Forecast F2019-F2021 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Revenue Requirements Summary ($ million) | Extracted from F17-19 RRA | | | | | | | | Extracted from F20-21 RRA | | | | | | |
| | Actual F07 | Actual F08 | Actual F09 | Actual F10 | Actual F11 | Actual F12 | Actual F13 | Actual F14 | Actual F15 | Actual F16 | Actual F17 | Actual F18 | Forecast F19 | Plan F20 | Plan F21 |
| Cost of Energy (GROSS) | 1,091.2 | 970.4 | 1,282.8 | 1,209.9 | 1,309.1 | 1,043.0 | 1,057.3 | 1,309.3 | 1,512.5 | 1,475.6 | 1,505.5 | 1,538.7 | 1,673.4 | 1,887.0 | 1,920.2 |
| *Deferral Account Transfers* | *99.6* | *269.3* | *(216.7)* | *(16.6)* | *(155.5)* | *73.7* | *183.4* | *102.8* | *(204.9)* | *(195.9)* | *210.3* | *315.5* | *260.1* | *(152.0)* | *(152.0)* |
| Cost of Energy (CURRENT) (includes HDA & NHDA Rate Rider) | 1,190.8 | 1,239.8 | 1,066.2 | 1,193.3 | 1,153.6 | 1,116.7 | 1,240.7 | 1,412.1 | 1,307.6 | 1,279.7 | 1,715.8 | 1,854.1 | 1,933.5 | 1,735.1 | 1,768.2 |
| Operating Costs (GROSS) | 645.7 | 885.6 | 831.1 | 1,186.6 | 909.7 | 1,452.0 | 1,307.8 | 1,232.2 | 1,303.0 | 1,251.6 | 1,165.1 | 1,228.7 | 1,257.5 | 1,224.2 | 1,229.3 |
| *Regulatory Account Transfers* | *(89.7)* | *(334.9)* | *(182.6)* | *(540.7)* | *(153.0)* | *(506.5)* | *(378.5)* | *(457.3)* | *(367.0)* | *(265.8)* | *(174.2)* | *(255.9)* | *849.5* | *74.3* | *75.9* |
| Operating Costs (CURRENT) (includes Rate Smoothing & Gov't | 556.0 | 550.7 | 648.6 | 645.9 | 756.7 | 945.5 | 929.3 | 774.9 | 936.0 | 985.7 | 990.9 | 972.8 | 2,107.1 | 1,298.6 | 1,305.2 |
| Reverse Rate Smoothing & Gov't adjustment | - | - | - | - | - | (69.7) | (41.2) | 110.9 | 166.2 | 121.2 | 201.2 | 326.2 | (814.9) | - | - |
| Operating Costs (CURRENT) (before Rate Smoothing & Gov't adjustment) | **556.0** | **550.7** | **648.6** | **645.9** | **756.7** | **875.8** | **888.1** | **885.8** | **1,102.2** | **1,106.9** | **1,192.2** | **1,299.0** | **1,292.2** | **1,298.6** | **1,305.2** |
| Taxes (GROSS) | 147.1 | 158.6 | 166.7 | 172.6 | 177.4 | 184.2 | 194.1 | 202.1 | 206.1 | 213.1 | 223.1 | 231.1 | 242.2 | 249.8 | 262.2 |
| *Regulatory Account Transfers* | - | - | *1.7* | *5.5* | *5.6* | *(14.0)* | - | - | *2.6* | *3.4* | *0.4* | *1.9* | - | - | - |
| Taxes (CURRENT) | 147.1 | 158.6 | 168.4 | 178.1 | 183.0 | 170.2 | 194.1 | 202.1 | 208.7 | 216.5 | 223.5 | 232.9 | 242.2 | 249.8 | 262.2 |
| Amortization (GROSS) | 378.5 | 363.4 | 388.0 | 437.4 | 501.4 | 586.2 | 635.0 | 656.8 | 691.7 | 739.5 | 777.9 | 807.6 | 871.5 | 915.7 | 936.5 |
| Finance Charges (GROSS) | 456.0 | 434.5 | 495.1 | 384.0 | 495.4 | 558.6 | 576.3 | 652.2 | 664.1 | 746.6 | 579.2 | 805.9 | 684.6 | 757.5 | 726.9 |
| Return on Equity (GROSS) | 407.0 | 369.0 | 365.6 | 447.0 | 588.9 | 558.4 | 509.3 | 549.5 | 580.8 | 655.0 | 683.5 | 684.0 | (424.3) | 712.0 | 712.0 |
| Total Capital-Based Charges (GROSS) | **1,242** | **1,167** | **1,249** | **1,268** | **1,586** | **1,703** | **1,721** | **1,859** | **1,937** | **2,141** | **2,041** | **2,298** | **1,132** | **2,385** | **2,375** |
| *Regulatory Account Transfers* | *(11.0)* | *35.0* | *(11.6)* | *54.7* | *(88.3)* | *(93.1)* | *(40.1)* | *(82.9)* | *2.0* | *44.5* | *7.6* | *(184.1)* | *(49.6)* | *59.9* | *59.1* |
| Amortization (CURRENT) | 362.9 | 373.4 | 405.9 | 442.1 | 536.1 | 552.4 | 631.7 | 655.0 | 739.9 | 804.3 | 860.7 | 916.3 | 950.8 | 1,035.6 | 1,060.2 |
| Finance Charges (CURRENT) | 460.6 | 459.4 | 465.7 | 490.4 | 361.1 | 490.2 | 538.4 | 576.0 | 606.7 | 726.3 | 504.0 | 513.1 | 555.6 | 697.5 | 662.3 |
| Return on Equity (CURRENT) | 407.0 | 369.0 | 365.6 | 390.6 | 600.2 | 567.6 | 510.3 | 544.7 | 592.1 | 655.0 | 683.5 | 684.0 | (424.3) | 712.0 | 712.0 |
| Total Capital-Based Charges (CURRENT) | **1,231** | **1,202** | **1,237** | **1,323** | **1,497** | **1,610** | **1,681** | **1,776** | **1,939** | **2,186** | **2,048** | **2,113** | **1,082** | **2,445** | **2,434** |
| Powerex Net Income (GROSS) | (259.2) | (82.7) | (243.9) | (7.5) | (71.5) | (142.0) | (98.2) | 58.4 | (120.1) | (58.7) | (130.2) | (136.6) | (205.3) | (120.6) | (120.6) |
| *Deferral Account Transfers* | *(27.0)* | *(111.1)* | *(28.6)* | *(198.5)* | *(57.0)* | *20.7* | *25.2* | *(122.5)* | *91.4* | *3.6* | *64.0* | *71.9* | *153.1* | *(12.6)* | *(12.6)* |
| Powerex Net Income (CURRENT) | (286.2) | (193.8) | (272.5) | (206.1) | (128.5) | (121.4) | (73.0) | (64.1) | (28.7) | (55.1) | (66.2) | (64.7) | (52.3) | (133.2) | (133.2) |
| Non-Tariff/Misc. Revenue (CURRENT) | (45.2) | (31.4) | (44.0) | (55.2) | (102.4) | (80.8) | (116.4) | (122.4) | (129.8) | (133.8) | (143.4) | (143.7) | (151.6) | (237.7) | (243.7) |
| Inter-Segment Revenue (CURRENT) | (42.6) | (68.7) | 30.5 | (60.9) | (89.2) | (30.1) | (63.1) | (27.1) | (50.6) | (55.7) | (56.9) | (66.4) | (64.3) | (69.0) | (72.6) |
| Powertech Net Income (CURRENT) | (1.2) | (0.5) | (1.2) | (0.7) | (0.5) | (2.6) | (2.9) | (3.7) | (4.4) | (4.2) | (2.1) | (3.1) | (3.3) | (3.4) | (3.7) |
| Other Utilities Revenue (CURRENT) | (18.4) | (15.4) | (22.0) | (16.3) | (16.3) | (14.9) | (14.8) | (16.4) | (18.6) | (18.2) | (13.0) | (11.9) | (28.6) | (28.6) | (28.7) |
| Liquefied Natural Gas Revenue (CURRENT) | - | - | - | - | - | - | - | - | - | - | (0.4) | (1.3) | (0.3) | - | - |
| Total Other Incomes (CURRENT) | **(393.6)** | **(309.8)** | **(309.2)** | **(339.1)** | **(336.8)** | **(249.8)** | **(270.2)** | **(233.8)** | **(232.0)** | **(267.0)** | **(282.1)** | **(291.1)** | **(300.4)** | **(471.9)** | **(481.8)** |
| Total Revenue Requirement (including Rate Rider before Rate Smoothing) | **2,731** | **2,841** | **2,811** | **3,001** | **3,254** | **3,523** | **3,733** | **4,042** | **4,325** | **4,522** | **4,898** | **5,208** | **4,250** | **5,256** | **5,288** |
| Rate Smoothing & Gov't adjustment | - | - | - | - | - | 69.7 | 41.2 | (110.9) | (166.2) | (121.2) | (201.2) | (326.2) | 814.9 | - | - |
| Total RR after rate Smoothing (incl Rate Rider) | **2,731** | **2,841** | **2,811** | **3,001** | **3,254** | **3,593** | **3,774** | **3,931** | **4,159** | **4,400** | **4,696** | **4,882** | **5,065** | **5,256** | **5,288** |
| reverse Deferral Rate Rider | (10.1) | (55.7) | (14.0) | (29.7) | (112.9) | (87.7) | (179.7) | (187.2) | (198.1) | (209.5) | (223.7) | (233.2) | (241.2) | - | - |
| Total Rate Revenue Requirement after Rate Smoothing but before Deferral | **2,720.7** | **2,785.5** | **2,796.9** | **2,971.6** | **3,141.1** | **3,505.2** | **3,594.7** | **3,743.9** | **3,961.0** | **4,190.9** | **4,472.6** | **4,649.1** | **4,823.4** | **5,256.5** | **5,288.3** |
| *Check balances against Schedule 3.0* | 2,720.7 | 2,785.5 | 2,796.9 | 2,971.6 | 3,141.1 | 3,505.2 | 3,594.7 | 3,743.9 | 3,961.0 | 4,190.9 | 4,472.6 | 4,649.1 | 4,823.4 | 5,256.5 | 5,288.3 |

This summary financial data shows that, in the 10 year period of "Actual" results from F2008 to F2018, the Total Revenue Requirement (Current basis, before Rate Smoothing) increased by $2.4 billion (from $2.841 billion to $5.208 billion).

The largest contribution to that increase came from the Capital-Based Charges, which increased by $911 million (from 1,202 to 2,113 million, a 76% increase). BC Hydro Operating Costs were the second greatest component of the total increase, rising by $748 million (before Rate Smoothing, from $551 to $1,299 million, an increase of 136%). Together, the Capital-Based Charges and Operating Costs accounted for 70% of the total 10-year increase in Revenue Requirement.

In the same period, the Cost of Energy rose by only $614 million (from $1,240 to $1,854 million, a 50% increase). The historical data reveals that BC Hydro's Capital-Based Charges and Operating Costs together accounted for 70% of the increase in

Total Revenue Requirement, while the Cost of Energy, which includes IPPs, accounted for about 25%.

According to this data, the biggest cost factor that has driven rate increases is BC Hydro's Capital-Based Charges, which include the grouping together of Amortization, Finance Charges, and Cost of Equity, all of which have risen steadily over the past decade as a result of the huge increase in invested capital.

The rapid rise of Capital-Based Charges has resulted from the huge capital investments that BC Hydro has made in its own facilities, like dams and generating stations, transmission and distribution power lines. BC Hydro invested roughly $2 billion per year in those assets over the last 10 years, and continues to invest at an even greater rate over the next decade.

7.1 Given the actual historical data, please explain how the following statement can be made: "The largest components of the Revenue Requirement are composed of the "Cost of Energy"? Wouldn't the largest component more appropriately be the Capital-Based Charges?

7.2 Please explain how IPPs are "by far the driving force" behind the growth of the largest components of the Revenue Requirements when they are far less and growing at a slower rate than the Capital-Based Charges?

7.3 Does AMPC believe that the true cost of the Heritage Energy is fairly represented by including only the cost of the water rentals (approximately $7.00/MWh), while for the cost of the IPP energy, all the costs of the employees and the capital is included in the number? How does the cost of the Heritage Energy take into account the cost of the 7,000 BC Hydro employees or the $20plus billion in capital assets being employed?

**Response:**

7.1 and 7.2

InterGroup did not prepare the noted table and cannot attest to the accuracy of the transcription or analysis. InterGroup notes that BC Hydro indicated in CEABC 2.47.1 (Exhibit B-13), in regard to the table, that: "In the absence of further information, BC Hydro is unable to confirm whether this data table is suitable for analysis." Also note that in relation to the CEABC chosen baseline of 2008, this predates the integration of BCTC, which BC Hydro noted (at page 1-10 of the F2012-F2014 RRA) leads to costs included in Cost of Energy prior to integration and as other items

(such as operating costs) after integration. It is not known how CEABC adapted the values for this factor.

Capital-based charges are not a single category. This includes amortization expense, finance charges, and return on equity, which are driven by a wide range of factors such as government policy on ROE and changes in interest rates.

The selected years of 2008-2018 do not include periods of material escalation on Cost of Energy related to the current test period.

InterGroup has not suggested growth in operating costs is not a concern. However, growth has been somewhat more limited since F2015, especially compared to other cost categories.

7.3

InterGroup reported costs of supply based on the values reported by BC Hydro for variable costs.

The full cost of any generation source is made up of all related costs, whether fixed or variable. However, it would not be appropriate to include fixed costs in an analysis of variable costs.

If the intent is to compare the costs of supply from BC Hydro ownership versus IPP ownership, then a full comparison of comparable projects is required (e.g., the same generation if owned by BC Hydro or by an IPP), including an analysis of such factors as contracting costs, taxes, renegotiation costs, the benefits of long-term ownership in the interests of ratepayers, etc.

No such analysis was performed as part of preparing the evidence, and this is not the basis of InterGroup's submission in the current case.

**8.0 Reference: Exhibit C-11-11, Intervener Evidence filed by the Association of Major Power Customers of BC (AMPC), discussing the impact on industrial rate competitiveness of BC Hydro acquiring electricity from Independent Power Producers.**

Section 4.6, IPP AND OTHER COST ISSUES IMPACTED BY GOVERNMENT, paragraph 7 states (underlining added):

*"At the same time as the above cost pressures from IPPs were increasing, BC Hydro's costs in other areas were also rising, though not to the same dollar extent. Among the challenges for ratepayers is that there have been significant constraints on independent regulatory review of these cost pressures, particularly in regard to capital costs. These capital cost drivers show up in rates as increases in amortization expense (increase of approximately $600 million since F2009) and interest (increase of approximately $300 million since F2009 despite dropping interest rates) as well as theoretically in added ROE (increase of $712 million since F2009, though this rate component is not presently linked to asset values but rather comes from desired targets imposed by Government regulation), as shown in Table 4-3."*

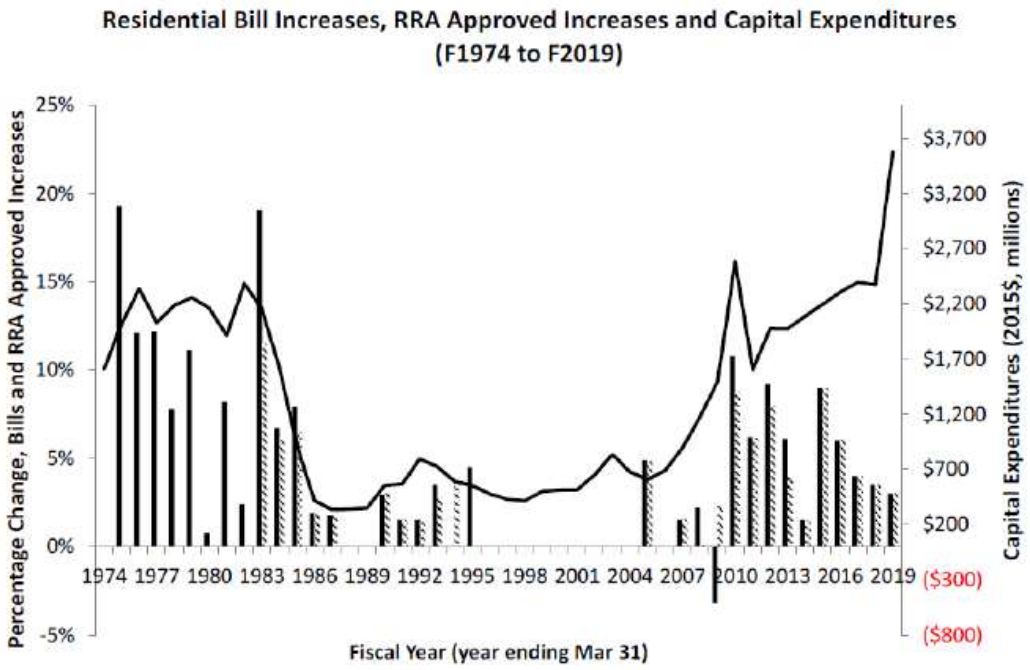
Paragraph 11 states (underlining added).

*"The end result of the period since 2002 is that, particularly because of IPPs, but also due to other constraints imposed by Government, ratepayers are facing rates that cannot be confirmed as just and reasonable nor consistent with least cost utility management. For IPPs the assessment has already been made by the Government commissioned review – costs are not consistent with prudent actions. For other areas, particularly capital-related costs, the assessment simply cannot be properly completed due to Government-imposed constraints."*

BC Hydro's 2017 News Release[35] answered the question *"Why do rates need to go up?" with "Its all about the need for system upgrades and the growing demand for electricity. Assets and equipment are ageing and in need of replacement."* It says nothing about the cost of IPP energy.

BC Hydro provided the following graph showing Capital Expenditures (restated in 2015 $) vs. % change in bills and Revenue Requirement increases from 1974 to 2019. (BCH response to CEABC IR 2.48.1)

[35] BC Hydro News Release "Why we're increasing rates: a look at how we're meeting growing electricity demand, March 17, 2017 found at https://www.bchydro.com/news/conservation/2017/increasing-rates-growing-demand.html




Recent BC Hydro Capital Expenditures are also shown on the following figure taken from the Comprehensive Review[36] (restated to 2020$). Between 2009 and 2018 Capital Expenditures averaged $2,100 million per year. Over that time the annual expenditure has doubled from $1,250 million to $2,500 million[37].

**Figure 5:** BC Hydro Capital Expenditures through the years


[36] Figure 5. Comprehensive Review of BC Hydro. Published February 15, 2019
[37] That does not include Capital Expenditures on Site C. Those started in 2015. In 2017 they were budgeted to be $10.7 billion.

8.1 Given this BC Hydro material showing the correlation of rate increases and capital expenditures, does AMPC still maintain that *"The largest components of the Revenue Requirement are composed of the "Cost of Energy". This cost has grown materially in past years, in both total cost and in average unit cost. By far, the driving force behind this growth has been IPPs…."* as stated in Section 4.6 of its evidence?

8.2 Please confirm that "interest" costs in paragraph 7 is equivalent to *"Finance Charges"* in Table 4-3.

8.3 Please advise why *"For other areas, particularly capital-related costs, the assessment simply cannot be properly completed due to Government-imposed constraints"* while *"for IPPs the assessment has already been made."* as stated in paragraph 11.

**Response:**

8.1

Yes. Cost of Energy is the largest category of BC Hydro's costs. It has increased more than any other category in recent years.

8.2

Interest is a component of finance expense (typically the largest component), although the latter can include amortization of financing costs, hedging transactions, sinking funds, amortization of debt discounts, etc.

8.3

There has been independent expert review of BC Hydro IPP procurement, and many capital projects have been exempt from BCUC review. Please also see AMPC's response to CEABC 1.1-1.3.

**9.0 Reference: Exhibit C-11-11, Intervener Evidence filed by the AMPC, discussing the impact on industrial rate competitiveness of BC Hydro acquiring electricity from Independent Power Producers.**

Section 4.6, IPP AND OTHER COST ISSUES IMPACTED BY GOVERNMENT, the last sentence in paragraph 8 states (underlining added):

*" …As such, similar to IPPs, the BC Government has imposed unjustified costs on ratepayers, and eliminated the normal ratepayer protections of independent regulation that would otherwise mitigate the risk of a natural monopoly."*

The recommendation/conclusion at the end of section 4.6 states (underlining added):

*"A number of costs are now explicitly acknowledged by either the BC Government (Independent Power Producer costs, Water Rentals) or the BCUC (Capital projects which merited an 'ex post facto' review to determine prudency) as not meeting the test for least cost utility planning or full and transparent regulatory review."*

BC Hydro stated in its 2010 Report on the Clean Power Call RFP that, *"The price to be paid for this electricity met BC Hydro's expectations based on comparisons to other BC Hydro processes and similar processes undertaken by other jurisdictions … [the] Call process has resulted in the acquisition of cost effective clean, renewable electricity for BC Hydro's ratepayers."*

BC Hydro stated in its 2012 Report on the Bioenergy Phase 2 Call that, *"The cost-effectiveness is also demonstrated by comparing the RFP results to other BC Hydro calls … Furthermore, the weighted-average Average Firm Energy Price for the Bioenergy Phase 2 RFP is lower than that for the Clean Power Call … The Bioenergy Phase 2 RFP awards are also comparable to recent Hydro-Quebec awards for biomass and wind projects."*

Most of the energy that BC Hydro has contracted to buy from IPPs is covered in electricity purchase agreements (e.g. Rio Tinto Alcan[38]) that were approved by the BCUC, and IPPs faced significant competitive pressure to submit low-cost bids in response to BC Hydro Calls for Power and RFPs.

9.1 Please describe how IPP costs were unjustified and did not meet *"the test for least cost utility planning or full and transparent regulatory review."*

[38] BCUC Decision, "A Filing of Electricity Purchase Agreement with Alcan Inc. as an Energy Supply Contract Pursuant to Section 71", January 29,2008.

**Response:**

9.1

Please see AMPC's response to CEABC IRs 1.1 to 1.3 and reference to reliance on the Zapped Report as summarized in InterGroup's evidence. Further, note that BC Hydro planning standards that set out the quantities of energy to be procured were not set by independent regulation but by Government policy (e.g., the 2007 Energy Plan) and normal alternatives such as BC Hydro ownership or other generation sources do not appear to have been approached on the same basis as IPPs. Imposing large quantities of power procurement in a short time frame while only considering some supply options (e.g., only IPPs) was not a strategy that appears to be considered on an independent basis and is not likely to lead to lowest cost supply.

The statement, "Most of the energy that BC Hydro has contracted to buy from IPPs is covered in electricity purchase agreements approved by the BCUC" cited in the question preamble cannot be commented upon in the time available.

**10.0 Reference: Exhibit C-11-11, Intervener Evidence filed by the AMPC, discussing the impact on industrial rate competitiveness of BC Hydro acquiring electricity from Independent Power Producers.**

**Section 4.7, INDUSTRIAL RATE DESIGN AND REBALANCING, paragraph 8 states (underline added):**

*"At the time of the 2002 Energy Plan, there was an overall consistent concept that BC Hydro would largely no longer develop its own power supplies (outside of some identified exceptions). Instead, the private sector, through IPPs, industrial generation, conservation, and increased market access, would become the new sources of supply."*

The 2002 Energy Plan enabled BC Hydro to make *"improvements at its existing facilities"*. The 2007 Energy Plan directed BC Hydro to *"Invest in upgrading and maintaining the heritage asset power plants and … potential capacity additions to Mica and Revelstoke generating stations."* The 2010 Clean Energy Act directed BC Hydro to submit a *"plan that includes the construction or extension of existing facilities … install two additional turbines at Mica … install an additional turbine at Revelstoke … and to … build a third dam at Site C."*

The result was that between 2002 and 2017 BC Hydro increased the generating capacity at its own facilities by 3,361 MW. The capacity increases occurred at 14 operating projects and two new projects.

The capacity increases at the 14 operating projects totalled 2,097 MW. The increases in capacity in those projects ranged from 1 MW to 1,000 MW.

**Table: BC Hydro Facility Capacity Increases from 2002 to 2017[39]**

| *Facility* | *2002 Operating MW* | *2017 Operating & Approved MW* | *Increase Operating & Approved MW* |
|---|---|---|---|
| *Hydro-elelctric* | | | |
| Aberfeldie | 5 | 25 | 20 |
| Ash River | 27 | 28 | 1 |
| Bridge River | 466 | 550 | 84 |
| Cheakamus | 157 | 180 | 23 |
| GM Shrum | 2,730 | 2,916 | 186 |
| John Hart | 126 | 132 | 6 |
| Kootenay Canal | 580 | 583 | 3 |
| Mica | 1,805 | 2,805 | 1,000 |
| Peace Canyon | 694 | 700 | 6 |
| Revelstoke | 1,980 | 2,500 | 520 |
| Ruskin | 105 | 114 | 9 |
| Seven Mile | 594 | 805 | 211 |
| Site C | - | 1,100 | 1,100 |
| Waneta | - | 164 | 164 |
| Fort Nelson Gas Plant | 45 | 73 | 28 |
| **Total** | 9,314 | 12,675 | 3,361 |

The total increase of 3,361 MW for all 16 projects represented a 36% increase in generation from those projects. It also represents a 33% increase in BC Hydro's total generation capacity, from 10,054 MW in 2002 to 13,280[40] MW in 2017.

10.1 Please provide evidence that *"At the time of the 2002 Energy Plan, there was an overall consistent concept that <u>BC Hydro would largely no longer develop its own power supplies.</u>"*

**Response:**

10.1

The referenced statement from InterGroup's evidence reflects the fact that the 2002 Energy Plan restricted BC Hydro's own new generation of electricity (unless otherwise approved by Cabinet) to improvements on existing facilities. Under the 2002 Energy Plan, new generation of electricity from new facilities was to be provided only by private sector IPP resources. This

[39] Table compiled by CEABC by extracting facility nameplate capacities that are listed on BC Hydro Quick Fact Sheets. They can be found at http://llbc.leg.bc.ca/public/PubDocs/bcdocs/358355/index.htm. Also at https://bchydro.com/energy-in-bc/projects/bridge-river-projects.html. Also at BC Hydro response to BCUC Directives 1 & 2 at https://www.bcuc.com/Documents/Proceeedings/2019/DOC_53841-A2-2-BCH-F17-19-ComplianceFiling.pdf. Also at BC Hydro CPCN Application to BCUC February 8, 2013.
[40] This total includes 1,100 MW for Site C which was approved in 2015.

reference is consistent with the question's quoted statement from the 2002 Energy Plan that BC Hydro was "enabled" to make "improvements at its existing facilities."

In regard to the 2002 Energy Plan, a BC Ministry discussion paper from the Industrial Electricity Policy Review similarly states that:

> Government indicated that the private sector would build new generation and BC Hydro would have a role in large hydroelectric projects in addition to maintaining and/or upgrading its existing facilities.[41]

The table provided in the preamble to the question above, shows that 3,361 MW of new BC Hydro capacity since 2002 includes 1,100 MW of Cabinet approved new generation at Site C that is not yet in service.

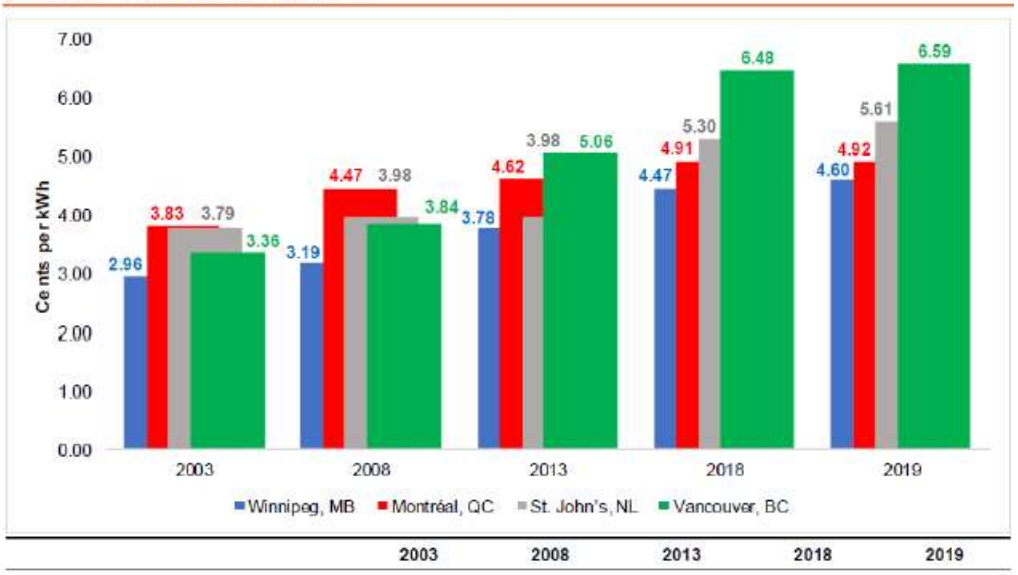
[41] Industrial Electricity Policy Review, background document: Ministry Discussion Paper, page 9, available online: https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/electricity/electricity-business/industrial-electricity-policy-review

## 1.0 Reference: Exhibit C11-11, page 1 and page 16

1. The BCUC should recognize and indicate a high priority to addressing issues of industrial rate competitiveness. The issue is important. Load reductions ~~or~~ and permanent load loss harm BC Hydro's ability to recover its costs, and ultimately affects all ratepayers through higher rates (Section 4.1). A clear BCUC finding in this proceeding will facilitate a consistent approach across the multiple near-term BCUC proceedings where industrial rate competitiveness concerns can be expected to arise (e.g., return on equity and rate design) (**Section 4.1**).

Figure 4-1 below provides a comparison of average electricity prices for a 50 MW industrial load customer (with supporting data table showing average rates) across the hydro-dominated provinces:

Figure 4-1: Comparison of average electricity prices in Vancouver for Large-Power Customers to other Canadian cities where the power source is predominantly from hydro[20]




1.1 Please confirm that Commercial rate competitiveness is also key to avoiding load loss and lack of competitiveness and options for this rate class can harm BC Hydro's ability to recover its costs and affect all ratepayers.

1.2 Please explain the relevance of the comparison to Canadian cities 'where the power source is predominantly from hydro'.

1.3 Please identify the major jurisdictions with which industrial load in BC competes.

**Response:**

1.1

Not confirmed. While the issue of competitiveness is obviously a concern for all customer classes, and may indeed be a larger concern for Commercial customers than for smaller loads, the importance of competitive electricity rates to the large industrial class is distinct.

For Commercial customers, energy costs do not generally make up the same percentage of total operating costs as for large industry, including large manufacturers and other energy-intensive operators. For AMPC members, energy costs can range from 10% - 60% or even greater of total operating costs. As a result, the financial risk for industrial customers, and correspondingly the risk to BC Hydro's revenue is higher compared to smaller commercial and general service classes.

Further, the impact of individual customers on BC Hydro's forecast revenues is not as significant for commercial rate classes compared to large industry. For the same concern to arise within smaller commercial classes, a significantly larger number of customers would need to reduce load or terminate service.

For example, the F2021 average usage per customer for the Commercial and Light Industrial class is 0.088 GWh.[1] For Large Industrial customers, the average usage per customer for F2021 is 74.6 GWh.[2] The impact of one average large industrial customer cancelling service is equivalent to roughly 850 Commercial and Light Industrial customers cancelling service.

Likewise, large industrial customers also often anchor residential and commercial loads in smaller communities the area. The cancellation of an industrial load can have ripple effects both in terms of other loads, and adverse social-economic consequences.

1.2

Comparing predominantly hydro utilities is relevant and important for energy intensive industries that do not depend on location-specific resources or operations.

Historically, hydro utilities have lower and more stable rates than electric utilities that use other generation sources. The cost structures are similar in that hydro assets have large capital costs during construction. But once construction is complete, costs are largely locked in and amortized over very long periods of time (100+ years) as hydro-electric generating stations are very rarely removed once installed. Ongoing operating costs are also quite low.

[1] 2020/21 RRA, Appendix O Table G-3 shows total Commercial and Light Industrial class sales at 19,036 GWh and BC Hydro's response to BCOAPO IR No 1.22.2 shows forecast number of customers for this class at 216,167 for F2021, or average usage per customer at 0.088 GWh
[2] Ibid - 14,702 GWh sales and 197 customers for Large Industrial or average usage per customer at 74.6 GWh

In comparison, the cost structures for other utilities fluctuate year-over-year due to fuel prices. Often other types of generating stations are not as long-lived and so the capital expenditures are more volatile in nature and annual operating costs are higher.

As hydro-electric generating stations provide large amounts of supply and dependable supply levels can be quite different from average or high supply levels, quite often utilities that build them interconnect with surrounding jurisdictions to make use of excess energy generation. In this sense, export/import sales and the amount of investment undertaken in transmission can be more comparable than utilities that use other generation sources.

Last, with varied carbon pricing requirements in Canada, hydro-electric utilities are mostly unimpacted by emission fees.

1.3

The competitiveness of the BC large power consumers is not tied to specific jurisdictions and varies considerably by sector. Generally competition is international and often output prices are set by external markets.

For sectors that are not dependent on natural resources or location specific operations, traditionally the lowest cost provinces in Canada include Quebec, Manitoba and in the past, BC. Other jurisdictions in the US such as Tennessee Valley offer incentives for electricity based on economic output and can offer quite competitive electricity pricing for specific industries – including manufacturing.

**2.0 Reference: Exhibit C11-11, page 1 and page 20**

2. The BCUC should find that absent the redirection of Deferral Account Rate Rider (DARR) funds into a Government-directed Return on Equity (ROE), customers would have seen a material rate reduction in F2020, all else being equal. (**Section 4.2**).

F2019 actuals indicated that conditions were materially improved (largely due to decreased water rentals and IPP purchases from dry conditions and increased Powerex Net Income, offset somewhat by increased market purchases)[27] compared to forecasts at the time of the Comprehensive Review, yielding a net balance owing to customers of $667.7 million.[28]

This set of conditions permitted setting the 5% DARR collection for F2020 down to 0%, offsetting some of the rate increase needed for Government to achieve the desired $712 million ROE for F2020.

Including setting the DARR to 0%, BC Hydro is able to propose rate increases to permit the full F2020 costs to be recovered, including full collection of the desired $712 million ROE, with limited net increase to customer bills. This means that rate reductions that may have otherwise been mathematically possible with the declining balances in the deferral accounts (notwithstanding the past policy that locked in the DARR at 5%) will not be seen by customers.

2.1 Please quantify the % 'material rate reduction' that might otherwise have been achieved or provide a range estimate.

**Response:**

2.1

Please see AMPC's response to BCUC IR 1.1 which details the potential rate and bill impacts.

**3.0 Reference: Exhibit C11-11, page 2**

3. The BCUC should note that, in its capacity as BC Hydro shareholder, the BC Government has elected to retain earnings of $2.2 billion over the period F2015-F2019. While this represents the Government foregoing a further $1.1 billion in returns for this past period, recovery of these amounts would have continued to harm the competitiveness of BC Hydro rates. This issue is now addressed and does not require further reversal or recovery in future (**Section 4.3**).

4. The added jurisdiction for the BCUC to set the Return on Equity is a positive development that increases the BCUC's ability scope to consider a wide and appropriate range of factors to assess the fair level of return in future. The BCUC should not be limited in its ability to take into consideration relevant funding source, risk, and shareholder policy issues in making this determination (**Section 4.4**).

3.1 Is AMPC requesting that the BCUC issue statements to this effect in the RRA Decision and/or take other actions such as communicating with the Provincial government? Please explain.

**Response:**

3.1

Please see AMPC's response to BCUC IR 2.1.

**4.0 Reference: Exhibit C11-11, page 2**

5. The BCUC should issue directives out of this proceeding that provide a clear scope for the coming ROE review so as to deal with matters prior to F2022. BC Hydro should be expected to provide materials to respond to this scope (**Section 4.4**).

6. The BCUC directives to scope the ROE review, in assessing whether the shareholder in fact has access to any material "profit" from an entity that has seen this level of extreme erosion in rate competitiveness, should explicitly take into account the following factors: 1) the extent to which the "equity" reported is in fact BC Government investment in the utility in the first place, 2) the extent of risk actually borne by the shareholder considering the range of regulatory directives, tools and deferral accounts, and 3) the extent to which an issue caused by Provincial Policy has undermined rate competitiveness (**Section 4.4**).

4.1 Please explain why AMPC believes it is important that the directives should be issued at this time and in this proceeding.

4.2 Would AMPC expect that the ROE review will include a scoping process? Please comment.

**Response:**

4.1

A BCUC review process for the ROE has been announced by the B.C. Government. Please see AMPC's response to BCUC IR 2.1 as to why InterGroup considers it important that directives be issued at this time and in this proceeding. AMPC agrees with InterGroup's analysis.

4.2

InterGroup prepared its pre-filed testimony in an effort to flag important considerations prior to any further rates being set given, whether that occurs through further government direction or, as expected, by the BCUC given its re-established regulatory oversight.

It would be anticipated that prior to BC Hydro filing a Revenue Requirement Application, with rates set to include a certain amount of Return on Equity, the Commission would issue directives for BC Hydro to consider, review or file as a Minimum Filing Requirement to support its ROE.

Intervenor comments on scoping have proved helpful in the past, and it is reasonable to expect that BCUC's review of the ROE would include a scoping process. Ultimately, however, it depends on the RRA decision, as a scoping exercise should not undermine sending strong

early direction to BC Hydro now about what is appropriate in its ROE application, but AMPC would support additional opportunities for customers to provide views about an appropriate ROE application review process.

Please also see AMPC's response to BCUC IR 2.1.

**5.0 Reference: Exhibit C11-11, page 2 and page 24**

7. The BCUC should direct BC Hydro to simplify the regulatory and deferral accounts as a long-term priority, to help ensure BC Hydro's costs are fully regulated, and are transparent to the regulator and impacted parties (**Section 4.5**).

8. Concerns tied solely to the magnitude of regulatory account balances should be viewed with caution. Failing to defer charges in a regulatory or deferral account when the costs would otherwise be recorded as current period costs and the benefits arise well into the future (such as with Demand Side Management) would be a highly inferior outcome from the perspective of fair rates and intergenerational equity, regardless of the fact that it might indicate lower deferral balances (**Section 4.5**).

- **Risk:** BC Hydro's deferral balances often serve to insulate the shareholder from risks that would be typical in any competitive and most regulated environments. For example, risks tied to load forecasts or variances in costs for capital additions are often part of the risk profile for a utility investor. In BC, these are partially if not fully addressed via regulatory and deferral accounts, which lowers the risk for the shareholder and insulates the Net Income from typical risk factors but does not necessarily lead to customer rate stability. This issue must be considered in detail as part of the review of ROE-setting for BC Hydro, including alternatives that either make the BC Hydro shareholder risk more typical of utility investors, or options that reduce the ROE well below that typical of utility investors to recognize that BC Hydro's shareholder does not bear these risks.
- **Complexity:** Perhaps the most notable feature of BC Hydro's regulatory and deferral accounts that is not directly addressed by the AG is the issue of the complexity associated with these accounts, which makes transparent regulation difficult. No government owned Canadian utility appears to maintain regulatory accounts with as broad a scope and function as BC Hydro. More importantly, the means by which BC Hydro reports the regulatory accounts makes deciphering year-to-year changes and cost drivers very difficult. This appears to be part of the root of the excessively large and complicated filings and information requests necessary to fully canvass BC Hydro's rate case.

5.1 Please provide examples of utilities for which the shareholder assumes the risk of load forecast.

5.2 Please provide examples of utilities for which the shareholder assumes the risk of capital additions variances.

5.3 Please provide examples of how the complexity associated with the deferral accounts contributes to difficulty in understanding of cost drivers.

**Response:**

5.1

Examples are provided below of regulated electric utilities in Canada where the shareholder assumes the risk of load forecast (variance between forecast and actual). This load forecast risk can be subject to ratepayers continuing to bear the risk for factors beyond the utility's control (e.g., the impact of fuel price variances or variances in forecast water availability)[3], and is also subject to the utility retaining the right to apply to the regulator for rate changes to address load change impacts (including interim rate increases when urgently required due to unforeseen circumstances).

Utilities where the shareholder assumes load forecast risk include: Manitoba Hydro, SaskPower, Nelson Hydro, Yukon Energy, Qulliq Energy and Northwest Territories Power Corporation. This includes most traditionally regulated vertically integrated utilities.

Besides BC Hydro, Newfoundland and Labrador Hydro (NLH) has a Rate Stabilization Plan (RSP) which captures the load forecast variance as well as fuel mix and price variances. However, this fund is used strictly to capture short-term variances, is included as a rider on top of rates and is temporary in nature, adjusted annually. This is done to maintain transparency for ratepayers and as historically NLH has varied considerably in its electricity generation supply (between fuel, hydro, etc.) which has wide ranging cost impacts due to the isolated nature of the island portion of the electric grid which is now connected to the North American electrical grid.[4] Additionally, this mechanism does not apply to all customer types that NLH serves.

5.2

Examples of electric utilities in Canada where the shareholder typically bears the risk of capital addition variances include: Manitoba Hydro, Newfoundland and Labrador Hydro, SaskPower,

[3] For example, a variance in load from the forecast may lead to a change in thermal generation requirements; however, the utility's fuel costs for any such thermal generation change would continue to be determined based on the approved forecast fuel prices.

[4] Until early 2018 Island Interconnected System of Newfoundland and Labrador Hydro was isolated without any connection to the other electrical grids, therefore, the marginal generation source was Holyrood thermal generating station. The RSP is expected to be reviewed when Muskrat Falls generation station is commissioned. The RSP is expected to be reviewed when Muskrat Falls generation station is commissioned" add the following "For example, page 10 of Christensen Associates Energy Consulting report included in Rate Design Review application notes NLH's intend to replace RSP after completion of Muskrat Falls project. Available at http://www.pub.nf.ca/applications/NLH2013GRA-Amended/files/compliance/From%20NLH%20-%20Rate%20Design%20Review%20for%20Newfoundland%20Power%20and%20Island%20Industrial%20Customers%20-%202016-06-15.pdf

Northwest Territories Power Corporation, Yukon Energy Corporation, Qulliq Energy Corporation, Altalink Management Ltd, and ATCO Electric[5].

The common approach for utility rate setting is that test year revenue requirements are set based on the forecast test year ratebase, which reflects actual capital additions to date plus forecast capital additions expected to come into service in the test years. In this context, the utility shareholder assumes the risk of forecast to actual capital cost variances in the interim years between rate applications (as these cost variances do not affect rates and are not typically accounted for in any deferral accounts). In each rate application the utility shareholder also bears the risk that all of its actual or forecast capital costs for a project may not be approved for inclusion in rates, i.e., costs that are found to be imprudent, or for assets that are not used and useful, may not be approved by the regulator.

Regular rate applications, as well as review of depreciation methodology to ensure that the allocations of capital expenditures are appropriate for test years, can review the accuracy of capital addition forecasts and adjust accordingly.

These utilities can at times apply in future applications to true up capital assets, but when rates are set on a prospective basis the norm is that the utility is at risk during those test years for the actual capital investments made during the period.

For instance, there are write offs or disallowance of capital expenditures that are not recovered from ratepayers, whether as a result of a regulator findings of costs being not prudent or as the result of the utility's preference not to include.

5.3

In general the complexity associated with deferral accounts is largely because of the number of accounts and the relationship of these account recoveries and additions with its forecast costs.

BC Hydro's reporting makes deciphering year-to-year changes and cost drivers very difficult in two ways: 1) some reporting shows cost categories which include regulatory account additions which are not part of the revenue requirement, but excludes recoveries for those regulatory accounts which are part of the revenue requirement; and 2) the forecasting approach for many of these costs is not directly linked to the cost category, where the variance in forecast is recovered later through regulatory accounts.

[5] ATCO Electric does have a deferral account for direct-assigned capital projects related to aligning customer specific projects and customer contributions. AE bears the risk for all other capital additions. This is explained in its Proceeding 24964 2020- 2022 GTA application, page 10-61: https://www2.auc.ab.ca/Proceeding24964/ProceedingDocuments/24964_X0001.01_24964-X0001.01BL_0164.pdf

The use of many deferral and regulatory accounts tends to put the focus on tracking the various costs through forecasts, deferral accounts, etc. and less on the forecasts that BC Hydro uses to forecast test year revenue requirement.

To that end, the following provides examples of how the complexity associated with the deferral accounts contributes to difficulty in understanding of cost drivers:

- Treatment of Finance Charges - Total Gross Finance Charges are $874.9 million for F2020 and $743.3 million for F2021 compared to $1,192.2 million for F2019 actuals.[6] It is difficult to understand the year-over-year changes just looking at total amounts here. Without any further checking this would indicate that there are significant reductions in total finance charges in forecast revenue requirements. However, this is not the case as BC Hydro separately allocates portions to each regulatory/deferral account (so impacted by additions and recoveries), as well there is a finance charge deferral account to capture differences between forecast and actual volumes in addition. Further, while a cost related to finance charges, the annual amortization for the cost of hedged positions is recovered separately through the Debt Management Deferral Account.

- The Non-Heritage Deferral Account – This account captures the cost variance between planned and actual non-heritage related costs (IPPs, Gas & Other Transportation, Non-Integrated Area, Waneta 2/3 water rentals) as well as the domestic revenue variance (i.e. variances in customer load between planned and actual). As a result, it can be difficult to understand what the variances are communicating and if it was a one-off situation or a trend that should be considered in forecast. In addition, the account affects multiple components of revenue requirement and revenues, rather than a single variable.

- IFRS Pension Costs Regulatory Account, Non-Current Pension Costs Regulatory Account, PEB Current Pension Costs Regulatory Account – Other utilities have these same pension-related expenses and manage them within revenue requirement on an annual basis without the complexity that BC Hydro has introduced. These costs can have large variations depending on the underlying discount rate used and point of time calculations. However, these costs can be managed given they are largely well out into the future.

[6] Appendix A, Line 5 in Schedule 1.0 - Revenue Requirements Summary, Appendix A of the Evidentiary Update

**6.0 Reference: Exhibit C11-11, page 2 and 3 and page 27 and page 29**

9. There are costs included in BC Hydro's Application that contribute materially to the uncompetitiveness of rates, but are understood to be beyond the regulatory jurisdiction of the BCUC at this time, due to directions from Government. It is important to have such costs clearly Identified even If the BCUC cannot direct associated changes (**Section 4.6**).

10. With a return to full regulation, the BCUC must ensure future rate reviews consider and test the prudence and least cost nature of all costs that continue to be included in revenue requirement (even costs committed in previous periods, which have to date not been properly tested or adjusted in rates). A number of costs are now explicitly acknowledged by either the BC Government (Independent Power Producer costs, Water Rentals) or the BCUC (Capital projects which merited an 'ex post facto' review to determine prudency) as not meeting the test for least cost utility planning or full and transparent regulatory review (**Section 4.6**).

Figure 4-4: Average Unit Costs ($/MWh) for Various Supply Sources F2009-F2021[42]


Cost of Energy is reviewed further in Appendix E to this filing.

The end result of the period since 2002 is that, particularly because of IPPs, but also due to other constraints imposed by Government, ratepayers are facing rates that cannot be confirmed as just and reasonable nor consistent with least cost utility management. For IPPs the assessment has already been made by the Government commissioned review – costs are not consistent with prudent actions. For other areas, particularly capital-related costs, the assessment simply cannot be properly completed

due to Government-imposed constraints. For water rentals, the intent of the 2011 Government review appears to not have been fulfilled. In each of these areas, regulatory principles have been undermined, and ratepayers have been adversely impacted.

6.1 Please clarify the following lines in Figure 4-4 which do not seem to correspond to the legend:

_. Heritage Energy – Water Rentals (broken line with dot) is black or purple in the legend, but green in the graph.

_ . . Market Energy (green broken line with two dots) in the legend has no corresponding line in the graph.

_ _ Black broken line is in the graph but is not itemized in the legend.

6.2 If available, please provide the complete list of costs that the BCUC should identify as contributing the lack of competitiveness of rates at this time.

a) If not available, what process should the BCUC conduct in order to itemize these costs? Please explain.

**Response:**

6.1

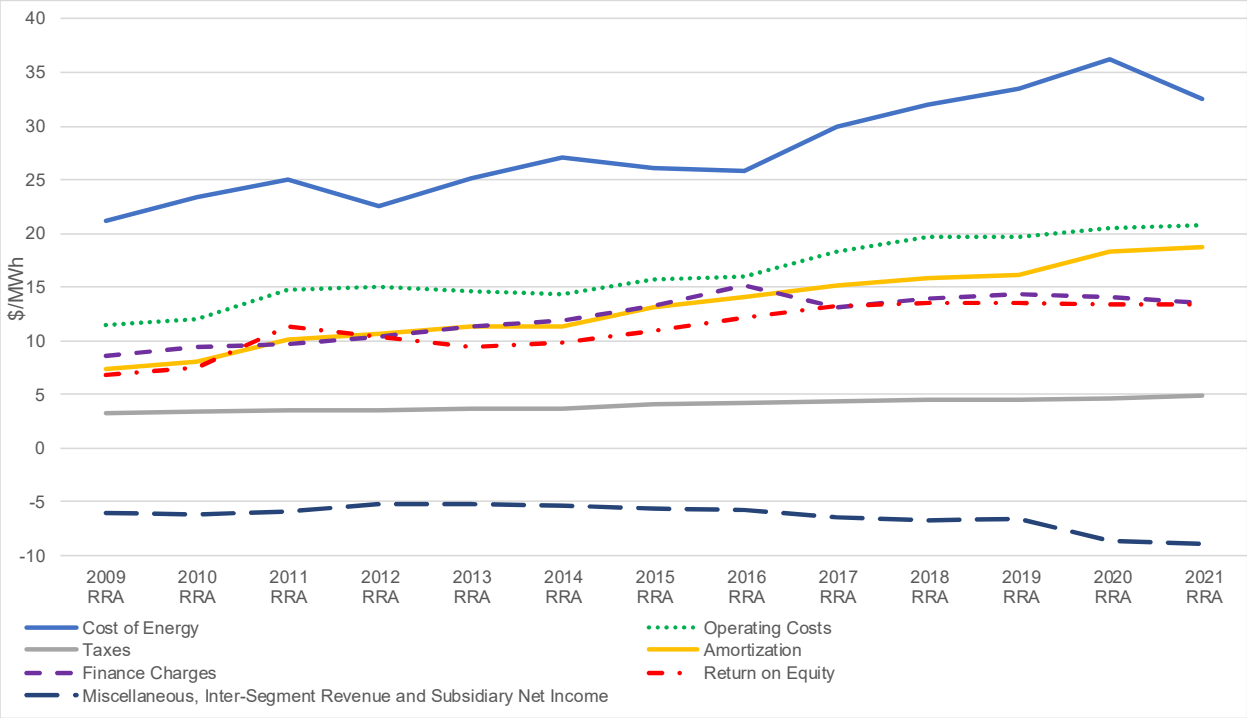
The Figure 4-4 legend is confirmed as follows (see Appendix E, Figure E-4 for detailed table):

- Heritage Energy – Water Rentals: this is the black broken line.
- Market Energy – Market Electricity Purchases: this is the green line with dash and dot.

6.2

Electricity rates are comprised of all revenue requirement costs. When considering competitiveness, or a lack thereof, all costs need to be reviewed in detail. The figure below shows major revenue requirement cost categories on a $/MWh basis, as approved in past Revenue Requirement Applications (i.e. approved costs that rates were based on).

**Figure 1: Revenue Requirement Cost Breakdown ($/MWh)[7]**




InterGroup did not undertake detailed analysis of all cost components resulting in rates but concerns have been raised in the pre-filed testimony about the following major cost categories:

- **IPP supply costs:** As shown in the figure above, the overall cost of energy has been largely increasing on a $/MWh basis over the long-term. From Figure 4-4 of InterGroup's evidence (provided in the pre-amble above), largely this increase is a result of IPP costs. As explained in Section 4-6 of InterGroup's evidence, the Zapped Review on BC Hydro's IPP power purchases noted that BC Hydro has bought too much energy and energy with the wrong profile, paid too much for the energy it bought, and undertook these actions at the direction of the Government (i.e. not subject to independent BCUC review).[8]

- **The scale of government charges:** The ROE component in rates (represented by the red dashed line in the figure above) has been set by Government for the long-term, without BCUC ability to weigh in on an appropriate level of return. Over this time period it has remained a consistently large overall component of rates (between 10-15% of total

[7] Prepared based on information available from Schedule 1.0 and Schedule 14.0 of Appendix A in the BC Hydro's F2017-F2019 RRA (Exhibit B-1) and Evidentiary Update to F2020-F2021 RRA (Exhibit B-19). Average cost per MW.h is calculated as revenue requirement component divided by total domestic sales. For illustration purposes excludes deferral and regulatory account recoveries.
[8] Section 4-6 of InterGroup evidence, page 25. Originally sourced from Zapped: A Review of BC Hydro's Purchase of Power from Independent Power Producers conducted for the Minister of Energy, Mines and Petroleum Resources, by Ken Davidson, February 2019.

costs). As noted in AMPC's response to BCUC 2.1, the approved level of return in rates allotted to the shareholder is an important consideration when assessing rate competitiveness.

- **Capital costs that have not been reviewed before the BCUC:** Also noted in Section 4.6 of InterGroup's evidence (starting at page 28), there have been significant regulatory constraints for review of capital costs, driving revenue requirement costs in amortization and finance charges. From the figure above, both cost categories have been increasing over the long-term, this at a time when long-term interest rates have maintained at low levels (resulting in sustained availability of low-cost borrowing). As noted in InterGroup's evidence, capital project overages (including the Northwest Transmission Line ("NTL") and the Interior to Lower Mainland Transmission Line ("ILM")) have been excluded from Commission review and as a result cannot be properly scrutinized.

A lack of ability to review depreciation methodology and consider how amortization costs may be set in a manner that supports the long-term nature of the use and usefulness of assets for ratepayers adds to this lack of competitiveness and is why InterGroup has recommended a depreciation methodology review take place for the next RRA.

**7.0 Reference: Exhibit C11-11, page 3 and page 33**

11. Given current challenges to industrial rate competitiveness and the changes to BC Hydro's cost of energy, Rate Schedule 1823 (Transmission Service) must be examined in the near term, including the design of Tier 1 and 2 rates. Otherwise, the policy intent of the rate is at risk, whereby industrial customers conservation and self-generation will be treated unequally relative to other long-term locked-in marginal-cost-based energy sources, such as Independent Power Producers (**Section 4.7**).

12. BC Hydro should bring forward the Cost of Service study for an open and transparent review with a clear intent to produce defensible Revenue to Cost ratios for each class. Cost of Service studies and fair Revenue to Cost ratios are important to setting the just and reasonable rates required by the *Utilities Commission Act* (**Section 4.7**).

Formal review of BC Hydro's cost-of-service study and any specific actions intended as rate rebalancing are now considered outside BCUC jurisdiction unless requested by BC Hydro,[51] based on government's stated ground that revenue-cost ratios are "a policy decision". This rationale is not applied in other jurisdictions and directly conflicts with the fundamental objective of achieving cost-based, just and reasonable rates. Insisting on utility authority to retain cross-subsidization of some customer classes by others is highly unusual within Canadian utility and BC Hydro history of regulation.

Outside of the perverse incentives for the utility, it remains to be determined whether there are appropriate changes that can be made to improve the design of Transmission Service customer rates (Rate Schedule 1823) that address this issue. It is recommended the utility prioritize rate redesign, especially if a review of energy and demand related costs and rates is forthcoming. This can be undertaken without violating the prohibition on rate-rebalancing between rate classes in the *UCA*.

7.1 Please provide AMPC's view of the 'near term'.

7.2 Please confirm that Commission Decision and Order G-5-17 addressed various principles regarding RS 1823.

7.3 Please elaborate on the changes that have occurred since this decision or other matters which necessitate additional review in the near term.

7.4 Would AMPC expect BC Hydro to address all rate class structures in another RDA application, or should the review be limited to industrial rates? Please explain.

7.5 If available, please provide supporting evidence that rate rebalancing is typically within the purview of the regulator.

7.6 Please elaborate on the 'perverse incentives' for the utility.

7.7 When does AMPC consider that BC Hydro should bring forward the Cost of Service study? To the extent that a Cost of Service study identified R:C ratios that were inequitable, how would AMPC expect the Commission to proceed? Please explain.

**Response:**

7.1

For this particular recommendation on rate design, InterGroup was referring to a time period likely within the next one to three years given other regulatory matters being pursued in this time frame, including BC Hydro's Integrated Resource Plan, the Government Comprehensive Review Phase 2 outcomes, BC Hydro ROE setting, and likely others.

AMPC's view of the "near term" is the next one to three years for review of RS 1823.

7.2

Confirmed. Commission Decision and Order G-5-17 approved BC Hydro's 2015 Rate Design Application.

7.3

Commission Decision and Order G-5-17 was based in part on a negotiated settlement. A key component of the negotiated settlement was a commitment by BC Hydro to bring forward an open rate design application in F2019 – see page 5 of Appendix A to Order G-47-16. However, the government amended *the Utilities Commission Act* to prohibit rate rebalancing except on application by BC Hydro. In addition to BC Hydro's commitment to file a rate design application, the marginal cost of new electricity supply has declined year over year since Commission Decision and Order G-5-17, BC Hydro projects an energy surplus beyond 2030, and the competitiveness of BC Hydro industrial rates continue to erode.

Within this context, proper cost allocation and renewed rate design efforts are necessary to effect just and reasonable rates. While undertaking such rate design would be outside the scope

of this application, a Commission conclusion that rate design efforts are necessary and important in the near term is a fully available response to adverse effects that the proposed test period rate increases will have on industrial rate competitiveness.

7.4

Please see AMPC's response to Zone II IR 1.2.

For cost of service and rate rebalancing considerations it requires review for all rate classes. For Rate Design, InterGroup's focus was on industrial customer rate classes and does not have a specific recommendation on review of rate design for other rate classes. InterGroup's recommendation does not preclude rate design recommendations about other rate classes.

7.5

In InterGroup's experience, rate rebalancing is under the discretion of the regulator as part of regular rate setting across jurisdictions. Generally, regulators have broad discretion for setting just and reasonable rates, including the ability to rebalance amongst customer classes.

For example:

- The Alberta Utilities Commission, under the *Public Utilities Act*, Section 80(c) has broad discretion to set rates (including rebalancing amongst customer classes), including:[9]

  > may disallow or change, as it thinks reasonable, any such tolls or charges that, in its opinion, are excessive, unjust or unreasonable or unjustly discriminate between different persons or different municipalities, but subject however to any provisions of any contract existing between the owner of the public utility and a municipality at the time the application is made that the Commission considers fair and reasonable.

  Section 89: Fixing of rates and Section 91: Revenue and Costs Considered also provide guidance on rate setting abilities for regulators with broad discretion on considerations for just and reasonable rate setting.
- The Manitoba Public Utilities Board, similar to the AUC, has broad discretion for setting differential rate changes amongst customer classes, as set out in Section 77(a) of the Public Utilities Act:[10]
  - fix just and reasonable individual rates, joint rates, tolls, charges, or schedules thereof, as well as commutation, mileage, and other special rates that shall be imposed, observed, and followed thereafter, by any owner of a public utility wherever the board determines that any existing individual rate, joint rate, roll,

[9] Alberta Public Utilities Act, available online: http://www.qp.alberta.ca/documents/Acts/P45.pdf
[10] Manitoba Public Utilities Act, available online: https://web2.gov.mb.ca/laws/statutes/ccsm/p280e.php

> charge or schedule thereof or commutation, mileage, or other special rate is unjust, unreasonable, insufficient, or unjustly discriminatory or preferential

Most recently this was implemented for the rate increase effective May 1, 2018, which was rebalanced amongst customer classes at different percentages according to revenue/cost ratios.[11]

- Under *Public Utilities Act*[12], Newfoundland and Labrador Board of Commissioners of Public Utilities the Board has general supervision of public utilities and requires that a public utility submit for the approval of the Board the rates, tolls, and charges for the service provided by the public utility. Specifically:

> **70.** (1) A public utility shall not charge, demand, collect or receive compensation for a service performed by it whether for the public or under contract until the public utility has first submitted for the approval of the board a schedule of rates, tolls and charges and has obtained the approval of the board and the schedule of rates, tolls and charges so approved shall be filed with the board and shall be the only lawful rates, tolls and charges of the public utility, until altered, reduced or modified as provided in this Act.
>
> **73.** (1) All tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate, and the board may by regulation declare what shall constitute substantially similar circumstances and conditions.

- The Northwest Territories Public Utilities Board has been issued policy directives from the Government of NWT to limit rebalancing for certain rate classes between 1% - 3% in an effort to gradually transition rate classes into reasonable revenue to cost ratios.[13]

7.6

The perverse incentives arise in that the utility is incented to keep complicated and contentious topics away from regulatory review, particularly if such topics would indicate material unfairness or cross-subsidization upon a fair and open testing. The incentive arises because critical review of a Crown utility is not typically viewed by the organization as a positive development.

[11] Manitoba PUB Order 59/18, as explained on pages 196 – 199. Available online: http://www.pubmanitoba.ca/v1/proceedings-decisions/orders/pubs/2018%20orders/59-18.pdf
[12] https://www.assembly.nl.ca/Legislation/sr/statutes/p47.htm [accessed on January 9, 2020].
[13] See Order 4-2017, page 2 where this 2017 Government Directive is explained. Available online: https://www.nwtpublicutilitiesboard.ca/sites/default/files/supporting/4-2017%20DECISION%20NTPC%202017-18%20Interim%20Rate%20Application.pdf

In many cases, the strongest pressures on a private utility relate to incentives tied to profits and losses, and ROE, but for a Crown the incentives are often viewed as stronger when tied to public testing of decisions and fairness issues.

The purpose of a transparent and strong regulator is to hold the utility to account, including in relation to issues of fairness related to the relative level of rates.

7.7

Cost of Service information should be brought forward for proper and open testing at the earliest possible opportunity, There would not appear to be any identified reason for delay. This should occur regardless as to whether BC Hydro's own Cost of Service studies indicate R/C ratios that are "equitable" or "inequitable" as the conclusions that matter are those that arise out of a BCUC review, not the utility's initial views. The utility's methodologies, facts and assumptions should all be subject to review by the regulator.

**8.0 Reference: Exhibit C11-11, page 3 and page 39**

> 13. BC Hydro should update its Test Year forecasts to include F2019 actuals in its Powerex Net Income forecast methodology and adjust rat es accordingly (**Section 5.1**).
>
> In addition, looking qualitatively, BC Hydro is applying to the BCUC to extend its 2018 Powerex Letter Agreement indefinitely, which BC Hydro explains provides an advantage for market purchases by allowing forward purchase of market electricity to secure physical supply of energy to address the risks associated with evolving system requirements.[59] This is a change that can occur for F2019 that was not included in the F2014 – F2018 Cost of Energy results. One of the main reasons to extend this agreement is due to decreases in supply on the Mid-C market driving day-ahead market prices up, which BC Hydro states it has "no basis to believe that the long-term decline in day-ahead market liquidity will quickly reverse itself".[60] These factors, included in F2019 actuals, indicate that at the very least inclusion of the F2019 actual results in the test year forecast (as one of the five years that is averaged) is likely appropriate as it is the most complete year that includes this Letter Agreement feature in Powerex transactions.

8.1 The 2019 Letter Agreement with Powerex application process is not yet complete. Please explain how this is a change that 'can occur' for F2019.

**Response:**

8.1

The sentence in question could equally read "This is a change that is not included in the F2014-F2018 Cost of Energy results".

Section 5.1 of the InterGroup evidence deals with whether BC Hydro should update its Powerex Net Income forecast with F2019 actual results. BC Hydro had a 2018 Powerex Letter Agreement in place over the F2019 year, accepted by the BCUC in Order E-15-19. It was filed with the BCUC on December 6, 2018 and effective over the period December 1, 2018 to June 30, 2019 (i.e. over part of F2019 and into F2020). It was made public on May 23, 2019 and is available online.

The effect of the 2018 letter agreement is likely to continue in future years because BC Hydro has applied to the Commission to approve the similar, multi-year "2019 Letter Agreement". As the letter agreement effects are likely to continue in the test period, the Powerex Net Income forecast should use F2019 actual results that reflect the operation of the 2018 Letter Agreement.

**9.0 Reference: Exhibit C11-11, page 3**

14. BC Hydro should update its finance charge forecasts for relevant known conditions and values to ensure the best available data is used to set rates. This is particularly true in an era where utilities have exhibited a trend of overforecasting finance charges (due to difficult to forecast market conditions). For the test years this includes reflecting long-term debt interest rates at levels consistent with debt locked in during the test years to date (**Section 5.2**).

15. For short-term debt rates, BC Hydro's forecast rates should reflect the best information available concerning present economic conditions, particularly as current rates are markedly lower for the test years than the rates incorporated in BC Hydro's forecast (**Section 5.2**).

16. If updated finance charge information also leads to concurrent changes to sinking fund rates, the test years should be adjusted to these updated levels (**Section 5.2**).

9.1 Please comment on when the Commission should make such a finding, and how and when it should be incorporated into the current evidence.

**Response:**

9.1

The Commission should make such a finding in its final determination on rates for the F2020 and F2021 test years. The results can be incorporated in a Compliance Filing by BC Hydro in its calculation of final rates.

These types of revenue requirement adjustments are very commonly directed by regulators in its revenue requirement applications and incorporated by utilities prior to releasing a final rate schedule.

Moving forward the Commission should direct the BC Hydro to update its interest rate forecasts in its Evidentiary Update, which is already a process BC Hydro undertakes partway through the regulatory calendar.

**10.0 Reference: Exhibit C11-11 page 3 and page 47**

> 17. The BCUC should strive to encourage consistency in treatment between the experienced gain for MSP premiums and the pension plan discount rate, in terms of known and projected information at a given point in time. The preferred outcome is to retain the 3.83% pension discount rate as identified and available for testing as part of the Original RRA Application, for both the current and non-current pension costs in the test years. Alternatively, if updated information regarding pension plan discount rates is incorporated into the test period, the experienced gain related to MSP premiums should likewise be included in the current test years under review (**Section 5.3**).
>
> To be clear, the recommendation is not for the BCUC to specifically reject the use of updated actuarial analysis when properly tested and supported as part of an RRA filing. The recommendation is that making a large and volatile change to occur on a non-cash expense (i.e. actual experience for pension costs is not likely to see volatile shifts in the short-term) within an Evidentiary Update, without any supporting analysis or considerations, is unreasonable especially given the impact on rates. This is particularly true when experienced gains in the same account are being deferred to future rate periods.

10.1 In AMPC's view, should the Commission encourage BC Hydro to match treatment for items within the same account regardless of the outcome in the future, or should the Commission encourage consistency in this matter in order to achieve a particular outcome? Please explain.

**Response:**

10.1

InterGroup generally recommends consistent treatment of comparable types of costs. If, unusually, inconsistent treatment is elected (to manage rate impacts, for example), the rationale for doing so should be explicit and it should not be accepted as common practice moving forward.

**11.0 Reference: Exhibit C11-11 page 3 and page 48**

> 18. There is significant basis for concern that BC Hydro's depreciation rates do not reflect reliable estimates of asset life and the consumption of service value in the test years. The BCUC should direct BC Hydro to complete a full depreciation study including assessment of the adequacy of accumulated depreciation balances. Such study should be completed prior to the next RRA and be slated for detailed review and testing at that time (**Section 5.4**).
>
> Currently, BC Hydro indicates that even though it has been 15 years since its last depreciation study it has no plans to update its depreciation parameters, as it has no indication that asset life expectations have changed in a significant way that would have a material impact on depreciation expense.[100] BC Hydro also states that its adoption of IFRS did not change the accounting principles applicable to the depreciation of property, plant and equipment.[101] Therefore, BC Hydro believes that the cost and effort of performing the study would outweigh the benefits.[102] For comparison, the cost of the F2005 study, not including internal BC Hydro staff efforts, cost $161,025.[103]
>
> This is an unusual conclusion. There are many accounts in BC Hydro's 2005 study that did not have extensive retirement experience, and the almost 15 years of time that have passed would typically help to review the adequacy of current service life estimates for these accounts, as well as determine if asset characteristics, technological advances or operational, maintenance or environmental considerations have resulted in changes to the depreciation parameters currently in place.

11.1 Please provide any evidence AMPC has as to how often depreciation studies are typically undertaken by utilities.

**Response:**

11.1

Please see AMPC's response to BCUC IR 5.1.