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May 2, 2019

Sent by eFile

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 Application (RRA)
Association of Major Power Customers of BC (AMPC) Information Request (IR) No. 1**

We are legal counsel to AMPC in this matter and write to enclose AMPC's IR No. 1 to BC Hydro. Please contact the writer if you have any questions.

Yours very truly,

Matthew D. Keen

Encl.

CAN_DMS: \127145619\1

Association of Major Power Customers of British Columbia (AMPC)

British Columbia Hydro and Power Authority (BC Hydro)
F2020-F2021 Revenue Requirements Application (RRA) – File 59886

INFORMATION REQUEST (IR) NO. 1 TO BC HYDRO

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REQUESTOR NAME: **Association of Major Power Customers of BC (AMPC)**
INFORMATION REQUEST ROUND NO: **1**
TO: **BC Hydro**
DATE: **May 2, 2019**
PROJECT NO: **File 59886**
APPLICATION NAME: **BC Hydro F2020-F2021 Revenue Requirement Application**

1.0 Load Forecast

Reference: Chapter 4 – Cost of Energy

On page 4-16 of the Application BC Hydro states that "the October 2018 rupture of the Enbridge T-South pipeline and subsequent gas curtailment resulted in Sumas spot gas prices reaching $66 USD/MMBtu in November 2018."

1.1 Did either of the constrained gas supply or the increased Sumas spot prices affect BC Hydro's load forecast? If yes, please explain how. If not, please explain how BC Hydro took these effects into account in the Application.

1.2 Many customers were required to switch fuels, or did so voluntarily, in response to the constrained gas supply and increased natural gas costs. Please identify, by month, the effect that such fuel switching has had on BC Hydro's load during the October 2018 – April 2019 period.

Reference: Appendix O, page 59 of 170; Tables 5-6 and 5-9

BC Hydro states that the "forecasted growth for the cannabis and cryptocurrency customers represent customer requested loads that are considered highly probable based on their advanced stage of progress in BC Hydro's interconnection process."

1.3 Please provide BC Hydro's expectation of the incremental load for each of these two customer types over the F2020-F2024 period.

1.3.1 Does BC Hydro expect the overall load associated with these two customer types to grow or contract beyond F2024? Please fully explain your response.

1.4 For the Commercial class, Table 5-6 shows a 0.6% decline in F2020 and further decline of 0.9% in F2021, compared to F2020. Please explain why BC Hydro is forecasting a continuous decline for this customer class.

1.5 Please explain the difference between the F2020 Commercial load forecast of 14,848 GW.h in Table 5-9 in Appendix O, and the 14,484 GW.h of Table 5-6 in Appendix O.

1.6 For the period F2015 through F2021, please provide by month:

1.6.1 BC Hydro sales by customer class.

Reference: Chapter 3 – Load and Revenue Forecast

On page 3-17 BC Hydro states that it "has increased the electricity price elasticity value used for all of the main customer sectors in the Load Forecast for this application from -0.05 to -0.10. The impact of changing the elasticity, all else being equal, results in a small net change to the total Load Forecast of about 21 GWh in fiscal 2020 and about 37 GWh in fiscal 2021."

1.7 What is the impact from this change to the revenue requirement and proposed rates?

On page 3-28 BC Hydro states that "a review of our fiscal 2018 Load Forecast variance showed a significant positive variance (higher actual loads relative to forecast) and negative variance (lower actual loads relative to forecast) for several industrial sub-sectors, notably forestry (positive variances) and oil and gas (negative variances)."

1.8 Please provide details of the variances by industrial sub-sector that BC Hydro notes.

On page 3-43 BC Hydro states that "over the test period, large industrial sector sales are expected to increase 730 GWh. As is shown in Table 3-8, this represents an increase of 699 GWh from fiscal 2019 to fiscal 2020 and then a decrease of 459 GWh from fiscal 2020 to fiscal 2021."

1.9 Please confirm that over the test period large industrial sector sales are expected to increase by 240 GWh (and not by 730 GWh as stated above).

On page 3-44 BC Hydro states that "at these prices, we expect existing coal operations to continue normal operations, and that no new mines will start operations over the next six years" and on page 3-28 BC Hydro states that "as part of our ongoing internal efforts to improve our load forecast methodology, we changed how we incorporate individual customer probability assessments into the first three years of our Large Industrial Sector Load Forecast (fiscal 2019 to fiscal 2021)."

1.10 For each sub-sector, please provide BC Hydro's corresponding probability assessment of new large loads?

1.11 With reference to Table 3-8 of the Application and Table 7-24 in Appendix O, please explain the variance between Large Industrial sales forecast for 2019 at 14,003 GWh in Table 3-8 and 13,856 GWh in Table 7-24.

1.12 On page 3-44 BC Hydro states that it "expects reduced sales from Mt. Polley relative to the above mid forecast starting in fiscal 2020." Please provide details of the impact from this decrease.

On page 3-45 BC Hydro states that over the test period "sales to the pulp and paper segment are expected to decline by about 782 GWh" and on page 3-46 "sales to the wood products segment are forecast to remain relatively stable with a small decline by 7 GWh."

1.13 Please confirm that Table 3-8 of the application assumes a 907 GW.h decline in the Forestry industry over the test period (from 6,668 GW.h in 2019 to 5,761 GW.h in F2021). If not confirmed, please fully explain your response.

1.14 Please provide BC Hydro's understanding of the reason(s) for the forecasted decline in the forestry sector.

2.0 Freshet Rate Revenue/Cost Impacts

Reference: Chapter 4 - Cost of Energy

The Comprehensive Review of BC Hydro Phase 1 Final Report, provided in Appendix C of the Application, states at p. 33:

> "BC Hydro is pursuing strategies to grow domestic electricity demand. As part of this, BC Hydro is exploring the option to offer current industrial customers year-round access to real time, market-based pricing for incremental energy purchases. For example, during the freshet period, there are high inflows into BC Hydro's reservoirs, resulting in surplus electricity generation that could potentially be sold at a discounted rate to industrial customers.
>
> BC Hydro is engaging with stakeholders and customers on these options and expects to file an application with the BCUC in 2019 regarding real time market-based pricing. If any of these strategies are approved by the BCUC, the impacts would be incorporated in future rates forecasts."

2.1 Please provide Freshet Rate sales and revenues for the period from F2015 to F2019, and forecast for F2020 and F2021.

2.2 Please provide the estimated impact of the Freshet Rate on the F2020 and F2021 load forecasts.

3.0 Operating Costs

Reference: Chapter 5 - Operating Costs

3.1 Please reconcile labour cost increases in Table 5-7 (line 18 of the table) on page 5-27 to the labour cost changes shown in Schedule 5.0, line 16 (increase in F2020 over 2019 RRA). Please provide details for each reconciliation item.

3.1.1 Please provide details of the labour cost increase from $509.1 million in 2019 RRA to $575.9 million in F2020 and further to $586.1 million in F2021.

3.1.2 Please provide a breakdown of the increase in labour costs due to added FTEs compared to increases in base salary and wages, premiums, overtime, vacation/flex time, pension, employer-paid premiums, insurance, supplemental benefits and training.

3.1.3 Please provide the table by business groups as per Schedules 5.1 through 5.7.

3.2 On page 5-28, BC Hydro states that "apart from growth in the workforce directly related to increased capital investment, BC Hydro's FTEs have remained relatively flat since fiscal 2012 and are forecast to remain flat over the test period." Please expand the table on page 1-19 to include vacant FTEs, as well as total labour cost and labour cost charged to capital for the period from 2012 to F2021.

3.3 On page 5-28 BC Hydro states that "FTE Increases are Driven by Capital Investment and have Reduced BC Hydro's Overall Costs." Please explain the reason(s) for the reduction in capitalized overhead in F2020 and F2021 compared to the previous years.

3.4 In Table 5-5 on page 5-23, BC Hydro states that cost increases related to the Employer Health Tax are partially offset by the elimination of Medical Service Plan premiums. Please provide a more detailed breakdown of the cost savings due to elimination of MSP premiums and the cost increase due to Employer Health Tax, including the impact of both to the total revenue requirements for F2020 and F2021.

3.5 On page 5-35 BC Hydro states that in the previous application filed in July 2016 BC Hydro had identified 170 additional FTEs as a result of the Workforce Optimization Program and notes that "since that time, the total number of FTEs added as a result of the Workforce Optimization Program has increased by approximately 535 to a total of approximately 706 FTEs, as additional conversions were confirmed for the fiscal 2017 to fiscal 2019 period as well as the upcoming fiscal 2020 to fiscal 2021 period." Please provide details concerning how many of the total of 706 FTE transitions are forecast to be vacant in each of the 2020 and 2021 test years.

3.6 Please confirm if all 706 FTEs referenced on page 5-35 are transitions of the existing contractors with experience working with BC Hydro.

3.7 Please provide a table showing the average labour cost per FTE for the contractor conversions compared to the existing FTEs for the KBUs noted in Table 5-10, and explain any notable differences.

3.8 Please detail how the additional costs for the FTE transitions, such as additional office spaces, office furniture, tools, equipment and other costs for the FTE transitions are reflected in the revenue requirements for F2020 and F2021. Please provide the average cost per FTE transition for these added costs.

3.9 Please confirm that 423 FTEs noted in Table 5-11 are additional FTE additions on top of total 706 FTE transitions noted on page 5-35. If not confirmed, please fully explain your response.

On page 5B-38 BC Hydro states that it is one of the largest property tax payers in the province with an annual property tax bill (Grants in Lieu and School Taxes) of approximately $250 million on assets assessed at over $11 billion. It also states that "given the significant size of this obligation, the department identifies opportunities to reduce current and future tax assessments. For example, in fiscal 2018 and fiscal 2019, combined annual savings of over $3 million were achieved through negotiations and appeals that will be reflected in reductions in future years' assessments."

3.10 Please explain why taxes as shown in the table at page 8-14 are forecast to increase by $11.1 million in F2020 over F2019 and a further $12.4 million in F2021 relative to F2020.

3.11 Please break out the individual impact of each factor noted on page 8-14 of the Application to the forecast tax increases, e.g., increased property values, taxation rates, increased revenues, etc.

3.12 With reference to Schedule 5.0 line 67, please explain the forecast increases in operations cost from $3.6 million in 2019 RRA to $6.5 million in F2020 and further to $7.2 million in F2021.

3.13 With reference to Schedule 5.0 line 74, please explain the forecast increases in operations costs from $6 million in 2019 RRA to $32.4 million in F2020.

3.14 On page 6-166, BC Hydro notes its plan "to keep some fleet assets in-service for longer periods" and "BC Hydro believes these investment levels are reasonable based on the age and condition of the fleet assets, expected requirements and mitigation plans." Please provide a summary of the fleet asset ages, expected requirements (including replacements) and referenced mitigation plans.

3.15 In Table 5-5 BC Hydro states that it continues to budget for storm restoration costs using a five-year average of normal weather years and "in recent years, we have experienced higher levels of storm related damage, which has caused the five-year average of storm restoration costs to increase". However, Appendix G, page 12 (2017 actuals) notes an increase in the Storm Restoration Costs Regulatory Account "of $18.6 million due to a harsh winter which led to higher than planned expenditures for storm restoration." A similar statement was made on pages 16 and 17 (2018 actuals) where BC Hydro states that "heavy snowfall in Vancouver Island and the Lower Mainland, and freezing rain and ice in the Fraser Valley during the winter which led to higher than planned expenditures for storm restoration." Please provide a five-year average based on normal weather conditions as directed by the BCUC.

4.0 Finance Charges

Reference: Chapter 7 - Regulatory Accounts

4.1 Please compare BC Hydro's proportion of short-term relative to long-term debt to the total debt portfolios of Manitoba Hydro, Ontario Hydro and Hydro Quebec.

4.2 Please provide the total mid-year net debt for F2020 and F2021 (showing long-term, short-term, sinking fund, etc.) and compare it to the mid-year rate base for F2020 and F2021.

4.2.1 Please provide a table that shows the mid-year balance of long and short-term debt and percentages of each from total debt balance for the period from F2016 through F2021. Please include RRA forecasts and actual results for F2016 through F2019.

4.2.2 Please provide a table showing the calculation of long-term debt costs including listing all existing debts, issue and maturity dates, interest rates and interest expenses. Please reconcile to the total long-term debt cost shown in line 86 of Schedule 8.0.

4.2.3 Please provide a table that shows sinking fund balances, sinking fund income and sinking fund income as percentage of total sinking fund balances for each year for the period from F2016 through F2021. Please include RRA forecasts and actual results for F2016 through F2019.

4.3 Please confirm that total debt costs included in the revenue requirement are calculated as follows: total mid-year net rate base less deemed equity portion = deemed debt portion multiplied by the weighted average cost of debt. If not confirmed please provide the approach used by BC Hydro.

4.3.1 Please explain the "WACD Adjustment" (lines 46 and 50, Schedule 8.0) and provide details of how it was determined. Please explain the differences and relationships between lines 46 and 50.

On page 7-59, BC Hydro states that BCUC Order No. G-77-12A set the interest rate applicable to BC Hydro's regulatory account balances in a given year as the weighted average cost of debt in that year, and the weighted average cost of debt that is forecast to be applied to the regulatory account balances is 3.88% for fiscal 2020 and 3.82% fiscal 2021. Schedule 8.0 shows that approximately 90% of the weighted average cost of debt reflect interest expense for long-term debt.

On page 7-56, BC Hydro states that it "applies the principle of matching costs with benefits to determine whether interest should be applied to a regulatory account balance."

Table 7-9 (Chapter 7) includes the following statement "these expenditures provide immediate, rather than long-term benefits and therefore should be recovered over a shorter period of time." As per Table 7-9, this statement relates to the following regulatory accounts Storm Restoration Costs, Amortization of Capital Additions, Total Finance Charges, Rock Bay Remediation, Arrow Water Systems, Remediation, Dismantling Cost, PEB Current Pension Costs.

4.4 Considering the foregoing, please discuss whether if it would be more reasonable to charge interest for the above accounts based on a short-term debt interest rate?

4.5 Considering statements in Table 7-9 regarding the noted regulatory account balances that are recovered over a shorter period of time, please provide details of other jurisdictions where the weighted average cost of debt is applied to the deferral account balances which are recovered over a similar shorter period of time.

4.6 On page 7-56 BC Hydro states that “interest applied to regulatory accounts does not have the effect of increasing or decreasing BC Hydro’s allowed net income, as the interest added to regulatory accounts is intended to offset the unbudgeted incremental interest costs that BC Hydro has incurred.” Please compare the forecast interest rates for the regulatory account balances in the F2017-F2019 RRA against actual interest rates. Please discuss whether there was any impact to the rate payers from the difference between forecast and actual interest rates applied to the regulatory accounts.

4.7 In Table 7-9 (Chapter 7) BC Hydro states that “non-cash provisions are not recovered in rates”. Schedules 1.0 and 8.0 shows that accretion expenses related to Non-Cash Provisions are included as part of the revenue requirements for F2020 and F2021. Please explain, and confirm if BC Hydro’s statement “non-cash provisions are not recovered in rates” is accurate?

4.8 Schedule 8.0 shows that accretion expenses for the non-cash provision regulatory accounts are included as part of revenue requirements. Schedule 2.2 shows that total balance of non-cash provision regulatory accounts at the end of F2020 at about $658 million and $623 million by end of F2021. Please confirm that the balances of non-cash provision are included as no cost capital in the capitalization of rate base. If not confirmed, please explain why not.

4.9 With reference to Schedule 8.0, please provide a table showing forecast interest rates included in the RRA and actual interest rates for long and short-term debt borrowings for 2015 through 2018. Please indicate the interest rates based on Future Debt Hedges.

4.10 With reference to Schedule 2.2, please provide a detailed calculation of Debt Management Regulatory Account additions for 2017 and 2018, and forecast for 2019.

5.0 Demand Side Management

Reference: Chapter 10 - Demand Side Management

5.1 Please provide in tabular format actual and forecast spending for F2017 through F2021 on optional industrial rate programs, such as Freshet and Load Curtailment programs.

5.1.1 Please comment on whether offering Load Curtailment during the 2018/2019 winter period would have been cost effective for BC Hydro, had it been available at similar volumes to the 2017/2018 winter.

5.2 Using information available from Tables 10-10 and 10-11 in Chapter 10 please provide average unit cost (or utility cost) for each DSM program by customer class (i.e., total spending compared to savings in MW.h or MW).

5.3 Please provide a table comparing total allocated DSM costs for each customer class compared to the class total revenues for the period from F2017-F2019, and forecast for F2020 and F2021.

5.4 Please separate industrial class costs, energy and capacity impacts shown in Tables 10-10, 10-11 and 10-12 into light industrial and large industrial.

5.5 Please explain why BC Hydro has reduced its capacity-focused DSM programs, as shown in Table 10-9.

5.6 On pages 10-8 and 10-24 in Chapter 10, BC Hydro states that in response to Directive 21 of BCUC Order G-47-18 BC Hydro increased expenditures targeted at the residential section by approximately 50%, reducing commercial and industrial program budgets. Please clarify whether the BCUC Order recommended an increase in residential DSM by reducing commercial and industrial program budgets, or recommended “more targeted DSM programs at residential customers”.

5.7 On page 10-29 BC Hydro states that “a levelized utility cost of DSM that is less than $30 per MWh means that the energy savings from DSM cost less than the price BC Hydro could receive on the market for selling any surplus energy resulting from DSM. DSM with a levelized utility cost less than $30 per MWh reduces BC Hydro’s overall revenue requirements and overall customer bills.” Please confirm that overall revenue requirement reduction benefits the overall system and not just a particular customer class. If not confirmed, please explain why not.

5.8 Appendix B of Appendix X, Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan – Conservation and Energy Management, shows avoided costs for generation capacity for fiscal 2020 to fiscal 2022 at $38 per kW-year (2018 $), increasing to $60 per kW-year for fiscal 2023 to fiscal 2031 and increasing to $123 per kW-year for the period beyond 2031. Please explain why the generation capacity avoided costs are expected to increase more than three times over a ten-year period, and provide the basis and calculations for each of these estimates (including confirmation that these cost exclude transmission, substation and distribution capacity costs). Please discuss the extent to which these costs can be “avoided” in the short term, i.e., if peak load reduction occurs, versus locked in once new generation is commissioned.

5.9 Appendix B of Appendix X, Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan – Conservation and Energy Management, shows avoided costs for energy, including Long Run Marginal Cost: $105 per MWh (Fiscal 2018 $) and Market Price: $30/MWh (Fiscal 2018 $) over a 15-year period from fiscal 2020 to fiscal 2034. Please provide the basis and calculation for the assumed long run marginal cost of energy and the market price forecast (in 2018$) to remain constant over the 15 year period referenced.

5.9.1 Is the Long Run Marginal Cost expected to remain at $105 per MWh in 2018$ through to fiscal 2034? If not, please provide forecasts for major changes during the period to fiscal 2034.

5.10 Do customer bill savings illustrated in Table A-6, Appendix A of Appendix X: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan – Conservation and Energy Management, reflect net savings after DSM cost allocated from BC Hydro and customer internal costs? If not, explain the basis for the estimated customer bill savings.

5.11 Which customer classes are focused under Supporting Initiatives (such as public awareness) as illustrated in Table A-1, Appendix A of Appendix X Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan – Conservation and Energy Management?

5.12 On page 10-29 BC Hydro states that "costs in the Total Resource Cost Test include both BC Hydro's costs and the cost to participants of implementing DSM initiatives." Please confirm that in most cases the large industrial customers may have material additional costs (new investment decisions, production shifts, etc.) in order to participate in DSM activities. If not confirmed, please fully explain your response.

5.12.1 Please describe how such industrial customer costs are estimated and included in the Total Resource Cost Test estimates.

5.13 Please provide a comparison of DSM cost allocation per kW.h by customer class for BC Hydro relative to other Canadian DSM programs BC Hydro is aware of.

5.14 On page 10-23 BCH notes that the expenditures related to EfficiencyBC are borne by the Government of BC, and not by ratepayers. Please provide details how the expenses incurred by BCH are compensated by the provincial government.

6.0 Rates

Reference: Appendix C - Comprehensive Review of BC Hydro, page 17

One of the Outcomes of the Comprehensive Review undertaken by the Government is:

> "As an outcome of Phase 1 of the Review, the government will re-empower the BCUC to set BC Hydro's allowed net income, following a two-year transition period for Fiscal 2020 and Fiscal 2021 where BC Hydro's allowed net income of $712 million will remain in place. This transition period will allow time for the BCUC to review BC Hydro's next Revenue Requirements Application and to undertake a separate process to determine an appropriate rate of return prior to resuming the regulation of BC Hydro's allowed net income in Fiscal 2022. Government may provide policy guidance to the BCUC and/or participate in regulatory proceedings to inform this process."

6.1 Please confirm that the Application does not consider appropriate rate of return levels, pending a future BC Hydro application. If not confirmed, please fully explain your response and discuss:

- Any reviews or considerations BC Hydro has undertaken regarding appropriate rate of returns for a Crown-owned utility in Canada.
- Whether BC Hydro anticipates special directions by Orders-in-Council, or regulation, specifying a required return.

6.2 Please provide BC Hydro's achieved and forecast rates of return over the F2011-F2021 period and compare them to Manitoba Hydro and Hydro Quebec over the same time period.

6.3 Does BC Hydro employ financial targets or metrics to benchmark its rate of return relative to other Crown-owned electric utilities? If yes, please describe those metrics or benchmarks.

6.4 Please provide BC Hydro's total actual and forecast payments to government by way of dividend, water rentals, and contributions in lieu of taxes over the F2011-F2021 period.

6.5 Please compare the number of regulatory/deferral accounts used by BC Hydro to those used by other Canadian Crown-owned electricity utilities.

7.0 Competitiveness

Reference: Appendix V and Competitiveness

On page 1 of Appendix V, BC Hydro states that the Electricity Rate Comparison Annual Report was prepared in response to section 8(4) of the *Clean Energy Act*, which states:

> "The authority must provide to the minister, in accordance with the regulations, an annual report comparing the electricity rates charged by the authority with electricity rates charged by public utilities in other jurisdictions in North America, including an assessment of the extent to which the authority's electricity rates continue to be competitive with those other rates."

7.1 Please confirm if the bill and rate comparisons in Hydro Quebec's Comparison of Electricity Prices in Major North American Cities used in Appendix V include rate riders.

7.1.1 Please provide a list of rates and riders included in the average price comparisons for BCH.

7.2 Please provide a comparative index, comparable to page 23 of Hydro Quebec's Comparison of Electricity Prices in Major North American Cities, 2018, of the average prices for the Canadian major cities included in Table 8 of Appendix V. Please also provide the information in graphic format.

7.3 With reference to the seven jurisdictions noted in Ministerial Order No. M167 of June 28, 2011 (Attachment B to Appendix V of the Application) please provide a table showing the following information. Please use the most recent information available, and select one appropriate utility from each jurisdiction.

- The average $/MWh price on April 1, 2019, for large power users
- total revenue requirement
- total load,
- total payments to government

7.3.1 For the total payments to government figure referenced immediately above, please prepare a separate table that displays the following information, to the extent it is available:

- o dividends and/or ROE,
- o Taxes or payments in lieu,
- o water rentals, or
- o debt guarantee fees

7.3.2 Please provide details concerning how such payments to government, including dividends, water rentals, and property taxes / equivalent, are determined in each jurisdiction.

7.3.3 Please calculate BC Hydro's ratio of operating costs to total domestic revenues for each year of the F2011-F2021 period. If available, please provide similar information for the seven utilities referred to above during that period.

7.3.4 For the seven utilities referred to above, please identify optional rate programs available to large power customers (such as freshet, load curtailment, etc.) that BC Hydro is aware of.

7.4 Please extend Table 12 in Appendix V to include 2007 through 2013, as well as 2019.

7.5 On Page 4-33 BC Hydro notes “EPAs which have expired and have not been renewed, and one cogeneration project that is no longer going ahead and has been removed from the forecast.” What is the cogeneration project?

8.0 Thermal Generation/Costs

Reference: Chapter 4 – Cost of Energy, Sections 4.6 & 4.7

Table 4-6 provides the forecast costs of natural gas, gas transportation, carbon tax, motor fuel tax and other costs associated with BC Hydro's Prince Rupert and Fort Nelson thermal generation facilities. Island Generation is a thermal IPP.

8.1 For the Island Generation IPP/Long-Term Agreement, please provide a breakdown of forecast and actual costs (confidentially if required) for the F2010-F2021 period (including F2019 actuals, if available), including: natural gas, gas transportation, carbon tax, motor fuel tax, standby/operating fees, other.

8.1.1 Please provide corresponding energy in GWh per year and hours the plant runs (if available).

8.1.2 Please separately provide by year the GHG emissions underpinning the carbon tax costs requested above.

8.1.3 Please explain where each of these costs flow through to BC Hydro's Revenue Requirement (within Cost of Energy cost categories), including any costs/revenues associated with the Island Generation that impact Powerex Net Income, Surplus Sales or Market Purchases.

8.1.4 Please specify who purchases natural gas and secures transportation for the facility.

8.2 Please provide a comparison of actual to forecast GWh and $ millions for the years F2010 to F2018 (similar to Tables 4-6 and 4-7 as provided in the F2012-F2014 RRA on pages 4-18 & 4-19).

8.3 How does BC Hydro forecast Island Generation usage amounts and costs in the test years?

8.4 How did the Enbridge pipeline explosion, experienced in the F2019 year, impact ratepayers on a cost and revenue perspective with respect to power generation and potential Powerex market opportunities (through either Powerex Net Income, Surplus Sales and/or market purchases)? Please include the effects of the explosion on Sumas gas prices in your response.

8.5 Please provide BC Hydro's current plans for renewal/termination of this contract following the April 2022 contract expiration date.

8.5.1 Please explain the factors BC Hydro will consider relative to any renewal, including potential alternative sources of peak/emergency generation.

8.6 What is the impact of the proposed Woodfibre LNG gas consumption on the operation of the Island Generation?

8.7 Please outline the policies or regulations in place for the use of Island Generation by BC Hydro and/or Powerex.

9.0 Increased revenues through sale of Low Carbon Fuel Standard (LCFS)

Reference: Appendix C – Comprehensive Review of BC Hydro, page 33

The Government Review Report states at page 33:

> "The Ministry of Energy, Mines and Petroleum Resources is currently undertaking a review of the LCFS program. As part of this review, regulatory and legislative changes could increase the number of LCFS credits available for sale. If adopted, these changes would generate incremental revenues for Powerex and its parent, BC Hydro, between Fiscal 2020 and Fiscal 2024. This incremental revenue would be incorporated in future rate forecasts."

9.1 Please outline all cost and revenue implications associated with this Government finding within the F2020 and F2021 test years.

9.1.1 Please provide more detail on known or considered regulatory and/or legislative changes in BC and other jurisdictions where Powerex trades that would impact revenues through these types of Low Carbon initiatives.

9.1.2 If BC Hydro has not incorporated these findings into its test year forecast, please explain the steps undertaken to better understand the implications of Low Carbon Fuel Standard credits for both Powerex and BC Hydro.

10.0 Heritage & Non-Heritage Hydro

Reference: Section 4.2 – Cost of Energy, pages 4-2 & 4-3

Pages 4-2 and 4-3 state:

> "BC Hydro has restructured the presentation of Cost of Energy in the revenue requirements model for clarity purposes. The financial treatment of energy costs, and the way the system is operated remain unaffected by the change in presentation."

10.1 Please confirm that BC Hydro's Cost of Energy restructuring does not result in any forecasting methodological changes and/or any financial changes for the RRA test years. If not, please explain.

10.1.1 Please provide a comparative Table 4-2 on page 4-19 that arranges the presentation in the old manner for the years F2017 – F2021. Please explain any cost variances between categories.

11.0 Cost of Energy Variance Accounts

BC Hydro notes at page 4-38 that Powerex's net income is applied as an offset to BC Hydro's overall revenue requirement and states at footnote 334 (p. 8-17):

> "Trade Income is the greater of (a) the amount that is equal to BC Hydro's consolidated net income, less BC Hydro's non-consolidated net income, less the net income of BC Hydro's subsidiaries except Powerex, less the amount that BC Hydro's consolidated net income change due to foreign currency translation gains and losses on intercompany balances between BC Hydro and Powerex; and (b) zero."

11.1 Please provide a detailed calculation for Powerex Net Income, Trade Income and BC Hydro Revenue Requirement as detailed above, for the actual and forecast years F2016 – F2021.

12.0 Reference: Section 7.7.1 – Cost of Energy Variance Accounts

Pages 7-23 to 7-25 state:

> "The purpose of the three Cost of Energy Variance Accounts is to defer the differences between forecast and actual revenues and energy costs for recovery or refund to ratepayers in future periods. These differences are non-controllable and can be positive or negative….
>
> The Heritage Deferral Account captures variances between the forecast and actual cost of Heritage Energy, Market Electricity Purchases, Surplus Sales and Domestic Transmission costs related to Surplus Sales…. In addition, the Heritage Deferral Account captures variances between forecast and actual costs and revenues for items approved by BCUC Order No. G-96-04, which includes Skagit Valley Treaty revenues.
>
> The Non-Heritage Deferral Account captures variances between the forecast and actual cost of Non-Heritage Energy which includes IPPs and Long-Term Commitments, and Net Purchases (Sales) from Powerex…. In addition, the Non-Heritage Deferral Account captures variances between forecast and actual costs and revenues for items approved by BCUC Order No G-96-04, variances between forecast and actual domestic customer load (referred to as the Domestic Revenue Variance), and subsequent Orders as noted above.
>
> The Trade Income Deferral Account (TIDA) captures variances between the forecast and actual Trade Income."

12.1 For each of the heritage, non-heritage and TIDA deferral accounts, as well as any related deferral account addressing power supply cost variances, please discuss how the account operates, including variables underlying the charges and credits, and address the extent to which the specified account affects BC Hydro's supply cost risk.

12.2 Please indicate how risk mitigation from the above accounts, in both quantitative and qualitative terms, affects BC Hydro's return on equity, and the appropriate target ROE.

12.2.1 Please comment on the implications of these Variance Accounts on ratepayers, including regulatory principles such as intergenerational equity and rate stability.

12.3 With the repeal of Direction 7, please confirm that administration and recovery of the three Cost of Energy Variance Accounts will be subject to the direction of the BCUC. If not confirmed, please fully explain your response.

12.4 Please provide a breakdown of each of the three Cost of Energy Variance Accounts by each variance the account collects for the years F2014 – F2019, as explained on pages 7-24 and 7-25.

13.0 Independent Power Producers (IPPs)/Electricity Production Agreements (EPAs) and Long-Term Commitments

Reference: Chapter 4 – Cost of Energy, Table 4-12 & Table 4-13, pages 4-29 and 4-30

BC Hydro states on page 4-31:

> "The majority of IPP forecast cost increases from fiscal 2019 to fiscal 2021 are related to existing EPAs**.** BC Hydro is not acquiring new resources from IPPs (other than a small number of new First Nations energy projects and some EPA renewals)."

13.1 Please provide an update of Table 4-12 and 4-13 that separately shows BC Hydro's proposed reductions and additions in Number of EPAs, GWh and $ Millions by Call Process for each year F2017 Actual – F2021 Plan.

13.2 Please provide a version of each of Table 4-12 and 4-13 that splits EPA by type of generating asset (e.g. hydro, wind, co-generation, etc.) instead of by Call Process.

13.2.1 Please specify terminations, deferrals and downsizes by type of energy generation.

13.2.2 Please specify any additions and/or growth by type of energy generation.

13.3 Please provide a table that tracks expiring EPAs by year, showing both the number of contracts and total associated GWh, for the next 10 years.

13.4 Please explain how BC Hydro forecasts IPP deliveries for the test years, both by type of asset and total generation.

13.4.1 Please explain how variances from this forecast impact ratepayers in the test years and/or in future years.

13.5 Please provide a comparison of forecast to actual IPP and Long-Term Commitments by energy type from F2015 to F2019.

14.0 Independent Power Producers (IPPs)/Electricity Production Agreements (EPAs)

Reference: Chapter 4 – Cost of Energy, Table 4-13, page 4-30

BC Hydro states on page 4-30 and 4-31:

> "The Accounting Adjustments shown in Table 4-13 largely reflect energy costs for EPAs which are accounted for as capital leases under the current accounting standards. For those EPAs that are deemed to be capital leases, for accounting purposes, their costs are recorded as operating costs, taxes, amortization, finance charges as well as Cost of Energy. The decrease in Accounting Adjustments from the fiscal 2019 forecast is due to a new accounting standard effective for fiscal 2020 (as further discussed in Chapter 8, section 8.12.1 and 8.13.3). Prior to this new accounting standard, three EPAs were recognized as capital leases. As of fiscal 2020, under the new accounting standard, these three EPAs are no longer accounted for as leases, and one EPA, previously included in Cost of Energy, will be accounted for as a lease."

14.1 Please explain the accounting adjustments row in Table 4-13 including methodology for forecast adjustments and impact on revenue requirement by line item (through costs, revenue and regulatory/deferral accounts).

14.2 Please explain why the three EPAs that were previously classified as capital leases are no longer eligible and the rationale for why a previously unqualified EPA now is considered a capital lease.

15.0 Energy Study, Water Flows

Reference: BC Hydro RRA, Section 4.4.2.1 Energy Study Inputs
Appendix DD, Energy Studies Process Audit F2019

BC Hydro states on page 4-15:

> "**The range of water inflow conditions:** Inflows to BC Hydro reservoirs are inputs to the Energy Study and are the largest drivers of energy production and reservoir operation. Inflows are driven by a combination of rainfall, snow pack and glacier meltwater. Once the snowpack has melted, usually towards the end of summer, rainfall becomes the primary driver of reservoir inflows.
>
> Seasonal inflow forecasts are made at the beginning of every month for each of 25 basins which contribute to BC Hydro's energy supply. Each inflow forecast incorporates the historical variability observed in meteorological conditions since 1973. The Energy Study accounts for this range of potential inflow scenarios in its forecast of generation and reservoir operations."

BC Hydro states on page 10 of Appendix DD:

> "The Energy Studies financial policy is outdated and requires updating….it was last edited in March 2011….Management will review and re-publish the [Energy Studies financial] policy by March 31, 2019."

15.1 Please provide a copy of the revised Energy Studies financial policy.

15.2 Please provide or otherwise describe the hydraulic forecast relied upon to develop the test period revenue requirements. In your response please discuss water level starting points, assumed inflows, the use or non-use of long-term averages and any specific modifications to them.

15.3 Please provide the hydraulic generation forecasts as at March over the last 5 years, based on the hydraulic forecast methods adopted for the current RRA. Please comment on the accuracy of each figure.

15.4 Please comment on how water storage levels influence BC Hydro system planning and operation for forecasting purposes (including in relation to future export/import opportunities).

15.5 How does BC Hydro use its historic hydraulic energy levels in its forecast for system operations? Please provide a detailed understanding of how BC Hydro reviews its actual hydrology information (including storage levels) to understand potential financial and system operation risks.

15.6 Please comment on the range used for the Load Forecast input on the Energy Study as compared to the Load Forecast set out in Chapter 3 and the methodological steps undertaken to include historic weather variability.

15.7 Please provide the historic potential range IPP supply used as an input in the Energy Study to forecast the test years F2020 and F2021.

15.7.1 Is there a probability distribution associated with the IPP supply forecast range? If so, please provide it.

15.8 Does BC Hydro undertake uncertainty analysis or quantify financial risks associated with inputs into its Energy Study (for example financial implications and potential for droughts)? If so, please provide the associated analysis.

15.8.1 What classifies drought-like conditions for BC Hydro?

15.8.2 Please discuss the relative probability of drought conditions and assumed duration based on historic hydraulic data?

15.8.3 What are the potential cost impacts to ratepayers from drought, if any?

16.0 Water Rental Rates

Reference: Section 4.6.1 Water Rentals Are a Function of Generation; Appendix C – Government Comprehensive Review of BC Hydro, page 41

BC Hydro states on page 4-21:

> "Water rental fees on the generation of energy are calculated as the actual energy output of the licence holder from the prior calendar year multiplied by the current year water rental rates. The current year rates are calculated as the previous year rate times the annual percentage change in B.C.'s Consumer Price Index. There are two tiers of water rental rates charged by the Government of B.C., which vary depending on the volume of energy produced."

Concerning the water rentals "Focus Area", Government's Comprehensive Review states at page 41 of Appendix C:

> "Work in this area examined water rentals paid by BC Hydro to the government and whether these charges are appropriate going forward, as well as elements of the *Water Sustainability Act*."

16.1 Please provide any supporting analysis that BC Hydro provided to assist with this topic area in the Government Review, including but not limited to any comparison of water rental rates paid in other jurisdictions, the underlying unit rate and total dollar value paid for the years F2017 – F2021 (if available).

16.2 Please extend Table 4-4 on page 4-22 to add associated total costs for each row from 2014 to 2021.

16.3 Please provide a comparable table separating out water rental fees that relate specifically to IPPs/EPAs.

16.4 Please provide any analysis BC Hydro provided government concerning the level of water rental rates charged by the B.C. government.

17.0 Powerex Exports/Imports – Market Purchases & Surplus Sales

Reference: BC Hydro RRA pages 1-46, 2-6 and 4-6

BC Hydro states on footnote 48 of page 1-46 of the Application:

> "The costs of Market Electricity Purchases, Surplus Sales, Net Purchases (Sales) from Powerex and Domestic Transmission - Export were previously distributed into Heritage and Non Heritage Energy costs, based on the Heritage Contract threshold of 49,000 GWh. As discussed in Chapter 2, section 2.2.1, as part of the Comprehensive Review, the Government of B.C. repealed Direction No. 7 to the BCUC, which included the Heritage Contract. The repeal of the Heritage Contract has no impact on BC Hydro or ratepayers; however, it provides BC Hydro with the flexibility to re-categorize its Cost of Energy for this application by creating a third category, Market Energy, which includes the four components – Market Electricity Purchases, Surplus Sales, Net Purchases (Sales) from Powerex and Domestic Transmission - Export."

On page 2-6 BC Hydro states:

> "As explained in Chapter 8, section 8.9, BC Hydro believes that it continues to be appropriate for Powerex's forecast net income to be included in BC Hydro's revenue requirements and that if Powerex incurs a loss, it should be borne by the shareholder. Powerex's net income continues to be forecast based on the historical five year average, and variances between actual net income and forecast net income are captured by the Trade Income Deferral Account. If Powerex's actual net income in a given year were to be less than $0, BC Hydro would only transfer the variance between forecast net income and $0 to the Trade Income Deferral Account."

Pages 4-6 to 4-7 state:

> "Market Energy is electricity purchased from or sold to Powerex through transfer pricing arrangements between Powerex and BC Hydro. The costs or revenues associated with these transactions are allocated to the following categories:
>
> - **Market Electricity Purchases:** This is often referred to as domestic purchases and represents market purchases of electricity from Powerex by BC Hydro to meet domestic load requirements. This does not 1 include purchases included in Net Purchases (Sales) from Powerex.
>
> - **Surplus Sales:** This is often referred to as domestic sales and represents sales of electricity to Powerex, when BC Hydro has generation in excess of its domestic load requirements. This does not include sales included in Net Purchases (Sales) from Powerex.
>
> - **Net Purchases (Sales) from Powerex:** This is often referred to as trade purchases (sales) and represents Powerex purchases/sales from/to BC Hydro for the purpose of trade related activities, provided that the BC Hydro system has the ability to accommodate those transactions. These are not purchases (sales) for domestic purposes.

- **Domestic Transmission – Export:** This represents transmission costs within B.C. related to Surplus Sales."

Page 8-17 discusses Powerex Net Income:

> "In the test period, Trade Income is forecast at $120.6 million per year in fiscal 2020 and fiscal 2021 (net of BC Hydro's allocation of business support costs as described in section 8.10), and is reflective of Powerex's average net income over the last five years (i.e., fiscal years 2014 through 2018). Using a five-year average as the basis of forecasting Trade Income is consistent with prior revenue requirement applications and is reasonable given the year-to-year volatility in market conditions."

17.1 Please explain how the above listed market energy categories impact Powerex Net Income and the Trade Income Deferral Account.

17.2 Please explain how BC Hydro differentiates between Powerex Net Income and other Powerex electricity transactions, if any, to record amounts in the Trade Income Deferral Account.

17.3 Please provide a summary of all annual transactions between the regulated operations of BC Hydro and Powerex along with the basic calculation of the related charges or credits and the associated quantity of power exchanged by category – Market Electricity Purchases, Surplus Sales, etc. – for the last five years (2014-2018) of actuals. Please compare to forecast amounts for each year and provide forecast and test year amounts for 2019 – 2021.

17.3.1 Please reconcile to Powerex Net Income in each year as shown in Table 8-11 including calculation of five-year average for the test years.

17.3.2 Please include a breakdown of gross revenues and related costs (including Transmission costs) associated with Powerex Net Income for each of the years discussed.

17.4 Please detail from part 2 above, how the Trade Income Deferral Account (TIDA) or other Deferral Accounts (including the Heritage Deferral and Non-Heritage Deferral) were impacted in each case of a variance and how the variance was amortized to ratepayers in each year. Please note where minimum or maximum transfer variance amounts have been reached and what the actual total loss or gain was to BC Hydro (government) in that year.

17.5 Please confirm if BC Hydro includes a maximum revenue contribution that BC Hydro will transfer to the TIDA account for variances between Powerex's actual and forecast net income.

17.5.1 If yes, please provide the terms of a maximum contribution and rationale for this approach, including regulation and/or past approvals that lead to this maximum contribution allotment.

17.6 Please outline all policies/procedures/rules in place that govern export and import capabilities related to Powerex transactions (market sales [imports] and surplus sales [exports]) as it relates to system planning and rule curve optimization and for protecting reservoir levels for domestic load.

17.6.1 Comment on specific constraints that Powerex operates under regarding minimum reservoir levels for domestic electricity requirements.

17.7 Please explain why BC Hydro uses the five year average for forecasting Trade Income. Have other methods been considered that base a forecast on expected conditions (market prices, water levels, etc.)? If so please explain. Please compare the 5-year average forecast of Trade Income with actual Trade Income for each of the last 5 years.

17.8 Please explain the extent, over the past five years and as forecast for F2020 and F2021, that BC Hydro and Powerex trade income reflects long term export sales versus short-term or opportunity sales. Please provide details of the length and overall value of the long term sales.

17.8.1 Does BC Hydro include its known contracted sales in its forecast?

17.9 Please comment, as available, on the financial impacts on Surplus Sales and Market Purchases related to the Enbridge pipeline explosion from October 2018 through March 2019?

18.0 Regulatory Accounts

Reference: Direction No. 7, Section 11 (Cost Recovery) Repeal

Page 2-9 discusses Section 11 of Direction No. 7and Section 4 of Direction No. 8:

> "This section directed the BCUC to not disallow the recovery in rates of the costs incurred with respect to:
>
> - The construction of extensions to BC Hydro's plant or system that came into service before fiscal 2017;
> - Energy supply contracts entered into before fiscal 2017;
> - The Rock Bay settlement;
> - Three First Nations settlements;
> - The October 4, 2013 settlement between Powerex and various California parties;
> - Costs incurred from the decommissioning of portions of Burrard Thermal not required for transmission support services; and
> - Costs deferred to the Smart Metering Infrastructure Regulatory Account.
>
> Section 4 of Direction No. 8 provides direction in this area to recover costs related to previous policy decisions by the Government of B.C. It states that the BCUC must not disallow recovery in rates of the balance of BC Hydro's regulatory accounts as at March 31, 2019. It also states that the BCUC must also not disallow costs incurred by BC Hydro with respect to:
>
> - The construction of extensions to BC Hydro's plant or system that came into service before fiscal 2017;
> - Energy supply contracts entered into before fiscal 2017, and
> - Debt servicing costs related to the Rate Smoothing Regulatory Account approved by Order No. G-48-14."

18.1 For each bullet listed above, please provide the associated cost corresponding to the Regulatory Account BC Hydro uses to amortize each cost item into rates. Explain the cost treatment for each of the costs incurred and the date each regulatory account was initiated. If the cost incurred is not collected through a Regulatory account please explain how costs are collected in rates and underlying amortization methodologies.

18.2 Please confirm, or otherwise explain, that after March 31, 2019 the BCUC must allow all costs incurred by BC Hydro with respect to the three points listed immediately above (construction of extensions that came into service before F2017, energy supply contracts entered into before F2017, and debt servicing costs related to the Rate Smoothing Regulatory Account).

19.0 BC Hydro’s Generation Strategic Asset Management Plan

Reference: Section 6.4.2 of BC Hydro RRA, page 6-41

For the first step in its “bottom-up” capital plan, BC Hydro states:

> “First, BC Hydro considers its Generation Strategic Asset Management Plan. This plan sets out ten year strategies for each facility category – Key, Strategic and Available - to support appropriate resource allocations and performance targets for the facilities.”

19.1 Please provide a copy of BC Hydro’s Generation Strategic Asset Management Plan.

19.2 Please set out the planned investments in $ Millions for each type of facility category – Key, Strategic and Available, for the 10 year planning horizon. Please additionally note if there are any corresponding energy or capacity additions or reductions due to planned generation asset management activities (through replacement, restoration, retirement, etc.).

19.3 Please comment on how BC Hydro incorporates prudent pacing and prioritization of restoration in its Generation Strategic Asset Management Plan to ensure investment activities are undertaken with consideration for cost implications. Please provide any policy documents or plans that BC Hydro has in regards to the pacing and prioritization of investment for asset restoration/replacement.

20.0 Site C Project Regulatory Account

Reference: Appendix A, Schedule 2.2; RRA Chapter 7, page 7-11

The Site C Project regulatory account is forecast to grow to $525.5 million by end of F2021, mainly as a result of continued interest collection since F2015.

BC Hydro states on page 7-11 of its application:

> "The Site C Regulatory Account, which is not yet being recovered in rates as the project is not in-service. In a future application, BC Hydro will propose that the balance in the account be recovered over the average life of the assets once the project is in-service, as that is the period that customers will benefit from those cost."

20.1 Please explain any differences in treatment, both regulatory and accounting, between costs in the Site C Regulatory Account and ongoing capitalized costs related to Site C. Please specifically comment on any interest collection/capitalization practices that may differ between these two cost treatments.

20.1.1 Please explain how amortization of both the Site C Regulatory Account and capitalized costs of Site C are anticipated to be charged to ratepayers once Site C is in-service. Explain any differences in potential methodology.

21.0 Rate Smoothing Regulatory Account

Reference: RRA, Chapter 7 – Regulatory Accounts, page 7-8

BC Hydro explains the impacts of the Rate Smoothing Regulatory Account write-off as follows:

> **"Rate Smoothing Regulatory Account has been written-off:** As part of the Comprehensive Review, BC Hydro ceased using the Rate Smoothing Regulatory Account at the end of the third quarter of fiscal 2019. The balance of the Rate Smoothing Regulatory Account was written-off in December 2018 in the amount of $1.044 billion, resulting in a reduction to BC Hydro's retained earnings and a forecast net loss for BC Hydro in fiscal 2019. This means that the cost of the write-off is borne by the Government of B.C. as BC Hydro's shareholder, and not by ratepayers. This write-off is a significant driver of the forecast decrease in the net regulatory account balance in fiscal 2019."

21.1 Please provide a schedule of any equity payments made by the Government of BC to BC Hydro.

21.2 What is the debt to equity implication of the $1.044 billion write-off? Please provide the supporting detailed calculation to compare with and without the write-off.

22.0 Rate Smoothing Regulatory Account & Deferral Account Rate Rider

Reference: Application, Chapter 7 – Regulatory Accounts, page 7-7

BC Hydro has requested the closure of the Rate Smoothing Regulatory Account:

> "Close the Rate Smoothing Regulatory Account in fiscal 2020 as this account has a zero balance and BC Hydro is not proposing to smooth rates over the fiscal 2020 to fiscal 2021 test period."

22.1 Please provide in tabular format the approved and actual Revenue and Revenue Requirements from F2015 - F2021, but separating the 5% DARR collection in each year from revenues, including any ancillary impact of the DARR on costs (such as interest, etc.).

22.2 Please confirm BC Hydro is requesting the BCUC to permanently close and eliminate the Rate Smoothing Regulatory Account in this Application.

22.2.1 If not confirmed, please fully explain your response.

22.2.2 If confirmed, please justify the continued collection of the $45 million Rate Smoothing Account debt servicing cost for each test year.

22.2.3 Please explain the calculation of the $45 million Rate Smoothing Account debt servicing cost for each test year.

22.3 Please provide actual and forecast debt servicing costs for the Rate Smoothing Regulatory Account over F2015-F2021 in tabular format.

22.4 Where is the $45 million Rate Smoothing Regulatory Account interest applied in Appendix A Schedule 2.2 Other Regulatory Accounts? Where is this cost applied in Schedule 1.0 Revenue Requirements Summary?

22.5 Please provide an updated Table 7-1 (RRA page 7-8) that separates interest collection by account and explains the impact of the continued collection of the $45 million on rates. Please provide an updated Table 7-1 without the $4 million interest payment in the test years.

22.6 How long does BC Hydro propose to collect interest charges associated with the Rate Smoothing Regulatory Account balance?

22.7 Does IFRS allow for the continued collection of interest for written off balances? If not confirmed, please explain how BC Hydro will reconcile this ongoing accounting transaction with its auditors and in its financial statements.

23.0 Depreciation & Property, Plant & Equipment

Reference: Chapter 7 – Regulatory Accounts
Chapter 8 – Other Revenue Requirement Items

Page 7-49 of the Application states:

> "In fiscal 2006 BC Hydro retained Gannett Fleming to complete a depreciation study, which was filed as part of the Fiscal 2007 to Fiscal 2008 Revenue Requirements Application."

At page 8-3 of the Application states:

> "BC Hydro is seeking approval for the depreciation rates of certain property, plant and equipment at the Burrard synchronous condense facility for fiscal 2020 and fiscal 2021."

At pages 8-5 and 8-6 BC Hydro provides a table of the expected useful life and depreciation rates for three new asset classes for which it is seeking approval, including Water Rights (finite), Infrastructure Rights, and LED Streetlights.

23.1 Please explain why BC Hydro did not file an updated depreciation study with this RRA.

23.2 Is BC Hydro's current depreciation study considered IFRS compliant?

23.2.1 Please provide any external auditor instructions or review that documents such compliance.

23.2.2 Please provide all background working papers that went into the review and testing of BC Hydro's depreciation study for IFRS purposes.

23.3 Please provide examples of other utilities that have converted to IFRS and calculated depreciation expense without the benefit of an updated depreciation study.

23.4 Please provide a copy of the last approved Depreciation Study for BC Hydro's Property, Plant & Equipment assets. Please confirm the regulatory proceeding, date and BCUC Order that reviewed and approved this depreciation study.

23.4.1 Please confirm that the associated depreciation methodology is still being utilized by BC Hydro for the calculation of its forecast depreciation expense in the Application. If not confirmed, please provide any and all updated depreciation supporting calculations, explain all depreciation methodological changes reflected in the Application, and explain why a supporting Depreciation Study does not accompany the Application.

23.4.2 Please provide a brief explanation of whether BC Hydro uses the "ASL" methodology or "ELG" methodology for calculating depreciation rates, and why.

23.4.3 Please explain whether BC Hydro accrues net salvage of assets in its depreciation study and provide details of any depreciation rate methodology changes that may have occurred since the most recent study approved by the Commission.

23.4.4 Please provide any updated depreciation analysis undertaken since the last depreciation study concerning retirement rate analysis, survivor/life curve, and net salvage calculations (if applicable).

23.5 Please provide a reconciliation of PP&E to the last approved depreciation study by account, including additions, retirements, etc. for all forecast and actual years since the last study was approved and for the test years F2020 and F2021. Please include in this the impacts of BC Hydro's IFRS Transition Account for IFRS Property, Plant and Equipment to reconcile before and after the accounting change.

23.6 Please provide details of the $300 million impact of IFRS conversion by depreciable account.

23.7 Please provide an update on the next Depreciation Study BC Hydro plans to undertake and when it plans to file with the BCUC.

23.7.1 What is the timing that BC Hydro generally undertakes between depreciation studies?

23.8 Please provide a comparison of the depreciation rates approved for the Burrard Synchronous Condense Facility assets during the F2017-F2019 period and the F2020-F2021 test period.

23.8.1 Please provide justify the proposed rate changes for these assets, including but not limited to rationales for year over year changes and comparison with peer utilities.

23.8.2 Please provide supporting schedules including net book value at Fiscal year-end 2018 (or the year used to calculate depreciation rates in the test year), calculation of depreciation expense for the test years, and supporting retirement history and life curve analysis underlying these assets.

23.9 For each of the three new asset classes BC Hydro is seeking approval of depreciation rates for, please provide the netbook value and associated depreciation expense for each of the test years.