Canadian Office and Professional Employees Union, Local 378 (aka MoveUP)

INFORMATION REQUEST ROUND NO: 1

BRITISH COLUMBIA HYDRO & POWER AUTHORITY

October 19, 2016

British Columbia Hydro and Power Authority

F2017 to F2019 Revenue Requirements Application ~ Project No. 3698869

1.0 Reference: Northwest Transmission Line, Exhibit B-1, Application Section 5.2.4

BC Hydro addresses the Northwest Transmission Line, [a 287 kilovolt transmission line between the Skeena substation and Bob Quinn Lake, and related facilities and contracts], and states that the higher than plan amounts in fiscal 2015 [of Contributions in Aid of Construction] were due to a change in accounting for the payments received under the umbrella agreement between Altagas and BC Hydro for the construction and development of the Northwest Transmission Line project,

1.1 Please provide the gross cost of the Northwest Transmission Line, and the date it entered service.

1.2 Please provide the amounts of Contributions received in Aid of Construction and the identities of the contributors.

1.3 Please explain the nature and the rationale for the change in accounting for Contributions received in Aid of Construction.

1.4 How many customers currently take service from the line?

1.5 Please provide a copy of any report detailing the loading on the line in F2016.

1.6 What is the forecast loading on the line for the test period?

1.7 What new loads does BC Hydro forecast for the line in the test period and subsequent years?

1.8 Under what circumstances will additional contributions be either receivable by BC Hydro or refundable by BC Hydro, and to/from whom?

1.9 Please provide the forecast costs of operating and maintaining the line in the test period.

2.0 Reference: Mica Units 5 and 6, Exhibit B-1, Application p.6-4

BC Hydro states that its growth capital expenditures total $23.1 million and include planned expenditures for Mica Units 5 and 6.

2.1 Please provide the expected final cost and in-service date of Mica Units 5 and 6.

2.2 Please provide the expected final cost and in-service date of all transmission upgrades triggered by the commissioning of the units.

2.3 Please provide the final report to the Board of Directors for approval to commence construction. Please provide a copy of the economic analysis performed to justify the expenditures.

2.4 Please provide the estimate of the amount of energy the new completed station forecast to produce in an average year, compared to the former 4-unit station.

2.5 Please provide a schedule comparing the output by month by high, medium and low load hours to enable the reader to understand how much firming and shaping will be made possible as a result of the addition of Units 5 and 6.

2.6 Please provide an analysis of the impact of the two new units at Mica on the output at Revelstoke units 1-5.

3.0 Reference: Revelstoke Unit 6, Exhibit B-1, Application p.3-50

BC Hydro states that Revelstoke Unit 6 is the next capacity resource planned and is being advanced as either a contingency resource for its earliest in-service date in fiscal 2022 or for the need in the mid-level forecast in fiscal 2027.

3.1 Please provide a schedule comparing the output of the 6 units compared to the 5 units by month by high, medium and low load hours to enable the reader to understand how much firming and shaping will be made possible as a result of the addition of Unit 6.

4.0 Reference: Site C, Exhibit B-1, Application Appendix G p.2of 17

BC Hydro states that it is proceeding with the construction of Site C, a project to build a third dam on the Peace River in northeast British Columbia to provide approximately

i. 4 600 gigawatt hours of energy each year, and
ii. 900 megawatts of capacity.

BC Hydro forecasts capital expenditures in the test period as follows:

Year	Amount $million)
F2017	743
F2018	717
F2019	829

4.1 Please provide details of l) the amount spent up to March 31, 2016 and ii) the amount committed as of that date.

4.2 Please provide a summary of BC Hydro's contingency plan to address either the suspension or the abandonment of the project following a successful legal challenge to the project taking place in the test period.

4.3 Please provide a calculation of the amount BC Hydro would incur to abandon the project and how it would propose to collect this amount from its ratepayers or owner.

5.0 Reference: Burrard Thermal Generating Station, Exhibit B-1, Application Table 2-6, Appendix K, p.15

BC Hydro states that it is exempt from sections 45 to 47 and 71 (Certificate of Public Convenience and Necessity & Energy Supply Contracts) of the Utilities Commission Act to the extent applicable, with respect to the Burrard Costs, which are defined as:

"the costs incurred by the authority in F2014 or a later fiscal year arising from the decommissioning of those portions of Burrard Thermal that are not required for

transmission support services, including, without limitation, employee retention costs incurred as a result of the decommissioning, costs incurred as penalties or damages that arise in consequence of the decommissioning, and the net increase in amortization expense in F2015 and F2016 arising from a Commission order under section 15 of this direction"

5.1 Please confirm that all Burrard Costs as defined in SD 7, have been incurred and deferred in the NHDA, as explained in Appendix K, p.15. If not, please provide a table setting out the remaining costs to be incurred, their forecast timing, and their accounting treatment.

5.2 Please provide BC Hydro's best estimate of the extra costs that its ratepayers will be obliged to bear during the test period as a result of the government's directions to decommission Burrard Thermal Generating Station, and relocate its dependable capacity to Mica.

5.3 Please provide all studies, reports, evaluations or other written documents of any nature within the custody or control of BC Hydro, prepared since January 2007 regarding the impact on system reliability and security caused by relocating ~917MW of dependable capacity from the load centre in the Lower Mainland to a location some 600 km to the North East.

6.0 Reference: Net Debt, Exhibit B-1, Application Appendix A Schedule 8, p.49

BC Hydro forecasts its net debt to increase to $21.964 billion at the end of F2019.

6.1 For F2017–F2024 please provide a table that shows the opening balance, forecast additions, forecast repayments and closing balance of both long and short term debt.

6.2 Please provide a statement of financial position that provides support for these numbers, including but not limited to:

- Net Income
- Dividend
- Amortization
- Deferral Account Additions

- Deferral Account Recoveries
- Regulatory Account Additions
- Regulatory Account Recoveries
- First Nations Provisions
- Environmental Provisions
- Capital Expenditures
- Contributions in Aid
- Change in Sinking Funds Line
- Change in Working Capital & Other

6.3 Please provide a copy of the most recent rating agency's (Moody's or Standard & Poors) report on the financial position and outlook for the province, which includes the outlook and forecast of BC Hydro's financial obligations.

7.0 Reference: SMI Theft Reduction, Exhibit B-1, Application Table 3-6 to 3-9 Energy Load and Peak Capacity resource Balance, and Section 5.4.6

BC Hydro claims that SMI Theft Reduction has reduced annual load and peak capacity by 83 GWh and 11 MW respectively per year.

BC Hydro also states that "[E]xpenditures for the project were incurred prior to fiscal 2015, however the assets were not put into service until fiscal 2016 due to a change in strategy for the Theft Detection Solution and a general delay in other smart grid related implementation activities".

7.1 Please provide a copy of the report and analysis that developed these numbers, detailing how the savings were achieved and when.

8.0 Reference: Existing and Committed IPP Resources, Exhibit B-1, Application Table 3-6 to 3-9 Energy Load and Peak Capacity resource Balance.

BC Hydro claims the following amounts of energy and capacity from existing and committed IPP resources:

	F2017	F2018	F2019
Energy	13,252	14,681	14,457
Peak Capacity	1,593	1,685	1,633

8.1 Please provide a Table showing the energy and capacity from the following cohorts of IPPs:

- Pre F2006;
- F2006 Call;
- 2008 clean call;
- Bio energy calls Phase I and II; and
- Other.

8.2 Please provide a summary of all executed EPAs still under development, and an indication of their COD. Please identify any in default and those that could be terminated by BC Hydro.

8.3 Please provide details of the IPPs BC Hydro states that it will renew in the period F2017 to F2019.

8.4 Given that BC Hydro is forecasting a surplus of both capacity and energy in the medium term future, please explain why BC Hydro seeks to renew them.

8.5 Reference: IPP and Long-Term Commitments, Exhibit B-1, Application Section 4.4.2.3

12 **Table 4-8 Electricity Purchase Agreement Summary[1]**

	Post-COD		Pre-COD	
Project Type	**Number of EPAs**	**GWh/Year[2]**	**Number of EPAs**	**GWh/Year[2]**
Non-Storage Hydro	58	6,233	12	1,193
Storage Hydro	11	4,904	1	148
Biomass	17	3,160	2	578
Gas-Fired Thermal	3	3,205	1	82
Wind	4	1,365	5	798
Waste	5	307	0	0
Biogas	7	126	0	0
Solar	1	2	0	0
Total	**106**	**19,302**	**21**	**2,799**

13 1. As of May 1, 2016, for projects connected to the integrated grid.
14 2. Represents the sum of expected energy deliveries assuming all projects are in-service.

Please provide a comprehensive list of all Post-COD and Pre-COD EPA's included in the Table above including their respective expiry dates.

8.6

Table 4-9 IPP and Long-Term Purchase Volumes

Call Process	Number of EPAs[1]	F2015 RRA (GWh)	F2015 Actual (GWh)	F2016 RRA (GWh)	F2016 Actual (GWh)	F2017 Plan (GWh)	F2018 Plan (GWh)	F2019 Plan (GWh)
Pre 2003 Electricity Purchase Agreements	32	3,502	3,577	3,493	3,210	3,307	3,350	3,139
2003 Green Power Generation Call	6	548	641	548	576	562	562	562
2006 Open Call	18	2,032	2,354	2,040	2,092	2,129	2,135	2,135
2008 Bioenergy Call - Phase 1	2	197	177	197	215	188	188	188
2008/10 Standing Offer Program	24	198	235	198	252	295	431	517
2010 Bioenergy Call - Phase 2	4	95	-	126	129	282	725	725
2010 Clean Power Call	20	1,180	1,141	1,247	1,323	1,818	2,705	2,863
2010 Integrated Power Offer	7	1,023	969	1,080	1,101	1,022	1,064	1,074
Negotiated Electricity Purchase Agreements	14	4,564	4,283	3,073	5,420	3,701	3,711	3,703
Expected Standing Offer Program Projects[(2)]	N/A	-	-	-	-	71	130	291
Total	**127**	**13,339**	**13,377**	**12,002**	**14,319**	**13,375**	**15,002**	**15,199**

1. As of May 1, 2016 for projects connected to or planned to connect to the integrated grid.
2. Includes one co-generation project.

On page 4-20 of the Application, BC Hydro indicated that the average cost of this portfolio was $93/MWh over this forecast period. Please provide the average cost per MWh per year for each of the 10 Call Processes listed above.

9.0 Reference, Net Load Uncertainty Exhibit B-1, Application Section 3.4.2.2

BC Hydro developed an uncertainty band around the load resource balance surplus/deficit[24] as shown in Table 3-8 and Table 3-9. Consistent with the approach taken in the 2013 Integrated Resource Plan (refer to section 4.3.4.3 of the 2013 Integrated Resource Plan), this uncertainty band is estimated by considering net Load Forecast scenarios. These scenarios are comprised of combinations of Load Forecast and demand-side management savings estimates, and include:

- A low Load Forecast combined with low demand-side management savings estimate[25] (a scenario with the least need for new resources, referred to as Small Gap); and
- A high Load Forecast combined with low demand-side management savings (a scenario with the most need for new resources, referred to as Large Gap).

In all cases, the same LNG load was included in the Load Forecast. The resulting Load Resource Balance surplus/deficit for these net load scenarios are shown in Table 3-8 and Table 3-9.

9.1 Please explain why BC Hydro declined to build into its uncertainty band the uncertainty regarding the forecast LNG Load?

9.2 Reference: Load and Revenue Forecast Exhibit B-1, Application Section 3.2.1.1 Liquefied Natural Gas

By fiscal 2024, the LNG Load Forecast increases to 2,662 GWh per year which represents the total of the announced loads.

Please confirm whether "announced" means confirmed or merely possible.

9.3 Reference: Load and Revenue Forecast Exhibit B-1, Application Section 3.2.2.2 Large Industrial Sector, p. 3-17

Oil and Gas

Most of the growth in the sales to the large industrial sector over the test years stems from the oil and gas sector. Sales to the oil and gas sector are expected to grow by about 350 GWh per year between fiscal 2017 and fiscal 2018 and about 660 GWh between fiscal 2018 and fiscal 2019. This growth is primarily led by an expected increase in demand from gas producers in Northeast B.C.

From fiscal 2017 to fiscal 2022 sales to the oil and gas sector is expected to grow annually by 14.5 per cent. This trend is expected to remain strong over the medium and long-term; from fiscal 2017 to fiscal 2027 and from fiscal 2017 to fiscal 2036, electricity sales to this sector is forecast to grow by 8.8 per cent and 4.9 per cent, respectively. Sales growth over the medium and long-term is driven by new oil and condensate pipeline projects and gas producer and processor loads.

The projections in the oil and gas sector are highly uncertain because the magnitude of these loads vary dependent on factors including: increases in natural gas and natural gas liquids market prices (currently at low levels); final investment decision and approvals on LNG projects; and commitments to specific projects from gas producers that have requested electric service from BC Hydro.

9.3.1 What is the probability BC Hydro has calculated of this load growing as forecast?

9.3.2 Please provide the historical growth of this sector from 2010 to present.

9.3.2 Please discuss how BC Hydro assessed the uncertainties associated with this sector's load.

9.3.4 Does the Uncertainty Band fully encapsulate the degree of uncertainty associated with this sector's forecast load growth?

10.0 Reference: Smart Grid Program Exhibit B-1, Application Section 2.2.3

BC Hydro states that "[T]he Clean Energy Act also provides for BC Hydro to increase investments in clean, renewable energy across the province by completing the projects and programs listed in section 7 of the Clean Energy Act, including ..... the smart metering and smart grid program".

10.1 Please provide an analysis of what is generally understood within the electric utility industry in North America as a "smart grid", and how BC Hydro proposes to embrace the concept.

10.2 Please provide a schedule of investment projects, their timing, costs and their benefits.

10.3 Please indicate whether these costs will be exempt from Commission approval.

11.0 Reference: Mining Customer Payment Plan Exhibit B-1, Application Section 1.3.3

BC Hydro states that in February 2016, the Province announced a five-year Mining Customer Payment Plan program, under which major mines would be allowed to defer payment of up to 75 per cent of two years' worth of their electricity bills, with repayment plus interest as commodity prices recover.

BC Hydro has stated that it has forecast no activity in the test period in the regulatory account it has created for this program.

BC Hydro also stated, "This arrangement is expected to mitigate some of the impact of low commodity price on load; however, the exact extent to which this arrangement will prevent load loss that otherwise would have occurred is unknown."

11.1 Please state at what prices BC Hydro expects the program to become operative for each of the mines listed in the special direction, and compare them with the current and forecast prices.

11.2 Is BC Hydro entitled to take any security against the amounts it may be owed?

11.3 If so, please explain how the amount of that security is calculated.

11.4 If not, please explain why BC Hydro is not entitled to take any security against these amounts?

11.5 Please define the ratepayer group or subgroup at risk should a major mine fail, for whatever reason, to repay its deferred electricity bills.

11.6 Please estimate the maximum exposure for BC Hydro's other ratepayers.

12.0 Reference: Smart Metering and Infrastructure Program Exhibit B-1, Application p.6-104

BC Hydro states that"[T]he Smart Metering and Infrastructure Program completed in fiscal 2016 and as such there are neither capital expenditures nor additions in the fiscal 2017 to fiscal 2019 test period".

12.1 Please provide all studies, reports, evaluations or other written documents of any nature within the custody or control of BC Hydro that seek to identify the savings flowing from the introduction of the Smart Metering and Infrastructure Program, compared with the manually operated analog meters, and provide an estimate of the savings to be realized in the test period.

13.0 Reference: Thermo-Mechanical Pulp Program Exhibit B-1, Application Appendix V p.29

BC Hydro states that:" [T]he Thermo-Mechanical Pulp Program assists BC Hydro's thermo-mechanical pulp customers to manage their electricity consumption and complete projects at their facilities. The program targets the six thermo-mechanical pulp sites and provides incentives for projects that help to manage their energy consumption".

13.1 Please provide details of the mills that will receive the cash from BC Hydro, how much will each mill receive, and what savings are expected?

13.2 How much will each mill be expected to contribute itself?

13.3 Under what circumstances will the amounts contributed by BC Hydro be refundable?

14.0 Reference: Surplus Sales Exhibit B-1, Application 4.4.1.7

BC Hydro forecasts surplus sales to be 4,962 GWh, 5,556 GWh and 4,517 GWh for fiscal 2017, fiscal 2018 and fiscal 2019, respectively, at average unit costs of $23.8, $27.1 and $28.6 per MWh respectively.

At the same time BC Hydro is paying IPPs $92.3, $91.3 and $94.7 per MWh respectively.

In B.C. Hydro's 2008 LTAP, counsel for JIESC (now AMPC) stated in his opening remarks:

"[T]he 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 (T3:182-3)."

14.1 Please confirm that the significant burden on BC Hydro's domestic customers presaged by Mr. Wallace will (all else being equal) be as follows:

Year	(S million)
F2017	3.400
F2018	3.567
F2019	2.986
Total	9.953

Derivation: MWh*(IPP unit price-Surplus sales unit price)

15.0 Reference: Deferral And Other Regulatory Accounts, Exhibit B-1-1, p. 7-4, Table 7-1, p. 7-6, Table 7-2; Direction No. 7 Fiscal 2024 forecast

Direction No. 7 states that the Commission "must set rates in such a way as to allow the regulatory accounts to be cleared from time to time within a reasonable period taking into consideration the rate caps."

BCUC IR 1.124.4 requested that BC Hydro provide (for F2017–F2024) "a table that shows the opening balance, forecast additions, interest and recoveries for each of the Cost of Energy Variance Accounts. Please include an explanation for the assumptions that were used to determine the forecast additions and recoveries."

15.1 In addition to the response requested, please indicate the major assumptions that drive BC Hydro's determination, and for each variable, provide a sensitivity analysis that will enable the reader to assess the probability of BC Hydro achieving its goal.

16.0 Reference: Application Overview, Exhibit B-1, p. 28, We Optimized Our DSM Plan

19 BC Hydro has eliminated or modified programs that are not as cost-effective or are
20 less aligned with customer expectations and system needs, while retaining or
21 expanding programs that align well with new priorities.

16.1 Please provide a list of DSM programs that are "not aligned with customer expectations" with an explanation of how each is misaligned.