REQUESTOR NAME: **Clean Energy Association of B.C. (CEBC)**

INFORMATION REQUEST ROUND NO: **2**

TO: **BRITISH COLUMBIA HYDRO & POWER AUTHORITY**

DATE: **March 6, 2012**

PROJECT NO: **3698622**

APPLICATION NAME: **F2012-F2014 Revenue Requirements Application (F12-14 RRA)**

1.0 Topic: Load and Revenue Forecast

Reference: Exhibit B-16, responses to CEBC IR 1.2.4

BC Hydro provided the data in an Excel model to show the history of the load by sector and per customer account.

1.1 Please provide a chart showing the use per customer account in each sector since F2000.

2.0 Topic: Cost of Energy

Reference: Exhibit B-16, responses to CEBC IR 1.5.1 and 1.10.1

The second table in the response shows the energy BC Hydro expects to purchase from various IPPs during the test period.

2.1 Of the line captioned "F2006 Call (including Brilliant)", how much of this energy is produced by the Brilliant project?

2.2 The Alcan 2007 EPA is forecast to produce over 3,300 GWh per year, which is higher than any previous year, and increasing over the test period. Why is this plant expected to produce more than it has historically, even though the Alcan smelter modernization is proceeding and should consume more energy than historically?

2.3 The response to CEBC 1.10.1 indicates that *"BC Hydro's forecasted purchases from Alcan would be reduced by about 400 GWh in F2013 and 1,000 GWh in F2014."* This does not seem to agree with the values in the table given in CEBC 1.5.1. Please explain the reasons for the difference between the two responses.

2.4 Please confirm that the total energy from the 2010 Clean Power Call and the Standing Offer Program is expected to amount to only 5% of the total IPP energy procured during the test period (1,910 GWh out of a total of 37,592GWh over the 3-year period).

3.0 Topic: Cost of Energy

Reference: Exhibit B-16, response to CEBC IR 1.5.2

CEBC asked for an explanation as to how the Carbon Tax affects the decision to dispatch the gas-fired ICG plant. All of the useful information was redacted.

3.1 What is the Carbon Tax per MWh expected to be charged on production from the ICG plant over the test period, and what assumptions is this amount based on (average heat rate, C Tax per T of CO2e, etc.)?

3.2 To what extent does the BC Carbon Tax apply to market purchases of electricity from outside B.C.? What is the Carbon Tax per MWh expected for Market purchases over the test period, and what assumptions is this amount based on (average heat rate, C Tax per T of CO2e, etc.)?

4.0 Topic: Cost of Energy

Reference: Exhibit B-16, response to CEBC IR 1.5.4

The answer to this IR was incomplete. The question asked, in part, where any revenue was recorded in the accounts.

4.1 When the surplus capacity is used to make sales of surplus energy, does it reduce the net cost of Heritage or Non-Heritage Energy?

4.2 When surplus system capability is made available to Powerex, how is the value of this capability charged to Powerex? And how is the profit on this use of system capability allocated between Powerex and BC Hydro?

5.0 Topic: Cost of Energy

Reference: Exhibit B-16, response to AMPC IR 1.28.1

In the response, BC Hydro states in part: "Mid-C index price (Mid-C Index Price) for that hour plus/less transmission charges and losses between Mid-C and the B.C. border."

5.1 When a Mid C Index Price is quoted on a transaction, is it the seller's responsibility to deliver, at its expense, the electricity to Mid-C?

5.2 What are the transmission charges and losses between Mid-C and the B.C. border?

5.3 Are these charges based on the cost of firm transmission? If not, what are they based on?

5.4 If imports for domestic purposes or re-export are consummated on the basis of a Mid-C Index Price and are interruptible, are the cost of these imports ever evaluated using the equivalent of a wind integration charge that is applicable when BC Hydro purchases wind generated energy from sources in B.C.?

5.5 What are the transmission charges and losses on the B.C. side of the border for an import transaction consummated on the basis of a Mid-C Index price? For an export transaction?

5.6 In the case of purchase by Powerex/BC Hydro of Columbia Treaty Downstream Benefits, for domestic purposes, what are the transmission charges and losses in the U.S.? In B.C.? Are they based on delivery from Mid-C if the transaction is consummated on the basis of the Mid-C Index Price?

5.7 Does Powerex ever pay BC Hydro for shaping and storage? If yes, under what circumstances? If not, why not?

5.8 Are any shaping and/or storage fees charged or accounted for with respect to electricity imported into B.C. by BC Hydro for domestic purposes? For re-export? If not, why not?

5.9 What it the relevance of Mid-C Index Price with respect to sales or purchases of electricity by BC Hydro/Powerex in the Alberta market for import into B.C.? Please explain how these transactions are costed between BC Hydro and Powerex under the Transfer Pricing Agreement or otherwise including transmission cost and losses within Alberta and B.C. and any shaping and/or storage fees?

6.0 Topic: Cost of Energy

Reference: Exhibit B-16, response to CEBC IR 1.5.3, sale of storage to BPA

According to a presentation prepared b the Bonneville Power Administration ("BPA") entitled: "Non-Treaty Storage Agreement Update-Public Open Houses May-June 2011" that can be found at http://www.bpa.gov/corporate/ntsa/documents/NTSA2011Presentation.pdf

> *"BPA and BC Hydro have agreed to non-binding terms for a new long-term non-Treaty storage agreement." This presentation indicates that a final agreement might be concluded by the end of the year*

6.1 What is the status of the preparation and execution of final and binding agreements with respect to this agreement?

6.2 How will the revenue from any agreement be accounted for?

6.3 How will the flexibility to operate BC Hydro's generation and transmission systems be impacted by any agreement?

6.4 Please provide the business case for the non-binding terms or any agreement.

6.5 Will BC Hydro be seeking BCUC approval for this agreement? If not, why not?

7.0 Topic: Safety

Reference: Exhibit B-16, response to CEBC IR 1.11.1

The table in the response shows the WorkSafeBC assessment rates for BC Hydro for the period from 2000 to 2013.

7.1 What happened to cause the assessment rate to drop dramatically in 2009, from 0.96 to 0.75?

7.2 What happened to cause the rate to return to 0.98 in 2011?

8.0 Topic: Capital Expenditures and Additions

Reference: Exhibit B-16, response to CEBC IR 1.12.1 to 1.12.5, re the capitalization of interest and overhead

CEBC inquired about the breakdown of capital expenditures into direct costs, capital overhead, and IDC.

In the response to CEBC 12.1, BC Hydro stated that all interest and capital overhead for each project is included in a capital account and is not brought into the Revenue Requirement until that project is put in service and its capital balance begins to be amortized.

In its response to CEBC 12.4, BC Hydro stated that these project capital balances have no effect on the allowed return on equity until the projects are placed in service and amortization begins.

8.1 Please confirm that CEBC's interpretation in the preamble is correct and confirm that the capitalized interest and overhead is calculated on the full amount of the capital expenditures up until a project is put into service. Please also confirm what interest rate is used in the various years to calculate the IDC.

8.2 Please provide a copy of the government's direction that BC Hydro shall use a deemed ratio of

70% debt and 30% equity for purposes of calculating the amount of the return on equity that is allowed to be recovered in the Revenue Requirements. Please also explain why the 30% ratio does not apply to the capital invested in projects before they are put into service.

In response to CEBC 12.2, BC Hydro stated that it does not forecast this breakdown on a project basis, but in CEBC 12.3, it did provide this breakdown with projects grouped by functional business units.

8.3 If BC Hydro does not make these estimates on a project by project basis, then how does BC Hydro calculate this breakdown of the costs to accumulate them into the totals by business unit?

8.4 The new tables 6-A and 6-1 provided in the response to CEBC 12.3 show a ratio of capital overhead to direct costs that is 20.7% in the F2011 Actuals, but is only 5 to 6% in the forecasts for F2012, F2013, and F2014. On what basis are the F12-F14 forecasts estimated, and why are they so much lower than the F2011 Actual?

8.5 Why does the ratio of capital overheads to direct costs vary so much between business units? And why does the ratio seem extremely high for the Distribution unit in the F2011 Actuals? (The ratio is over 75% for this business unit in the F2011 Actual.)

9.0 Topic: Capital Expenditures and Additions

Reference: Exhibit B-16, response to CEBC IR 1.12.6, and Exhibit B-15, response to BCUC IR 1.429.3, re the prioritization of capital expenditures

CEBC asked BC Hydro to describe "*the process by which BC Hydro rations and prioritizes its capital spending plans in order to control the pace of rate increases…".* BC Hydro's response referred to BCUC IR 429.3, in which the Commission staff asked, *"Please discuss how BC Hydro ranks projects and programs when competing internally for limited Capital funding."*

In its response to BCUC IR 429.3, BC Hydro stated that:

> *"BC Hydro is in the process of developing a methodology and process for enterprise wide capital prioritization… BC Hydro expects to implement enterprise wide capital prioritization in advance of its next revenue requirements application."*

9.1 In view of the fact that the next revenue requirements application will not take place for a number of years, how much capital investment is BC Hydro proposing to make before this prioritization methodology is in place and reviewed by the BCUC?

9.2 How much of the capital investment over the F12-F14 test period will be brought to the BCUC for approval on an individual project basis prior to the availability of this new prioritization methodology? How many projects and how many dollars?

9.3 How does BC Hydro propose that the BCUC should assess the public interest of individual projects prior to the availability of this new prioritization methodology?

10.0 Topic: Capital Expenditures and Additions

Reference: Exhibit B-16, response to CEBC IR 1.13.1 to 1.13.10 re BC Hydro properties

CEBC asked about the sale of property assets and the possible use of the proceeds to finance new capital investments.

In its response to 13.7 and 13.10, BC Hydro stated that it has never utilized a sale and lease back of properties.

10.1 Is BC Hydro fundamentally opposed to the sale and lease back of properties? If so, why, given that according to media reports, the Bank of Nova Scotia, which is the only Canadian bank that owns its headquarters, has put it up for sale to raise capital?

10.2 Does BC Hydro own the Edmonds building in Burnaby where some of its operations are located? If yes, what is the appraised value of the land and building? Why did BC Hydro purchase the Edmonds Annex building?

10.3 Does BC Hydro own its Dunsmuir head office? If yes what is the appraised value of the land and building?

10.4 Did BC Hydro sell its head office on Burard Street, a parking lot on the west side of Burrard Street and to the north of the YMCA and a parking lot immediately to the south of its head office which was the former site of the Dawson School? If yes, why?

10.5 How much land does BC Hydro hold in the vicinity of the Ingledow substation? What is this land currently being used for? How much if any is vacant?

In its response to 13.8 and 13.9, BC Hydro stated that it has sold 68 properties in the 5-year period from 2007 to 2011 (excluding the Tsawwassen residential properties) and applied the proceeds to offset operating costs, rather than to fund new capital assets.

10.6 How many dollars have been applied to offset operating costs in each of these 5 years?

In its response to 13.3, BC Hydro provided a table showing the total Net Book Value of 4,061 properties as being $134 million as at December 2011. BC Hydro also stated that *"Appraised values … are only undertaken for properties at the time of acquisition or disposition."*

10.7 If appraised values are not available, please provide the assessed values of the 4,061 properties, using the same tabular breakdown.

11.0 Topic: Capital Expenditures and Additions

Reference: Exhibit B-1-3, Chapter 6, Transmission Capital Expenditures

According to the media report set out below, the Bonneville Power Administration developed a new transmission line that cost $140 million under budget and was in operation 10 months early.

> *"BPA completes power transmission line early Associated Press YAKIMA, Wash. (AP) - The Bonneville Power Administration celebrated the completion of a new transmission line Friday to better incorporate wind energy into the Northwest power grid, even as questions mount about future wind energy development in the region.*
>
> *The line, which runs 79 miles along the Columbia River from McNary Dam to John Day Dam, is one of several planned in Washington and Oregon to get power from wind turbines east of the Cascades to urban centers on the west side.*
>
> *Crews finished construction about 10 months ahead of schedule and saved nearly $140 million _ the original budget was about $340 million, BPA administrator Steve Wright said.*
>
> *"There's an assumption that the public sector can't do things well, and this is an example that it can," he said. "It will be a significant benefit for ratepayers."*
>
> *Incorporating intermittent wind power into an antiquated regional power grid has been an ongoing technical*

challenge in the Northwest, where wind power generation has more than quadrupled since 2006.

To speed up the effort, BPA approached wind developers years ago and obtained commitments to buy into the transmission system, Wright said.

"When we had a whole bunch of developers show up in one area, putting the economics of the project together definitely made it work better," he said.

"It basically broke the logjam in the queue."

Recent developments, though, have some questioning the future of wind development, particularly in the Northwest.

Congress failed to extend a wind energy production tax credit, which supporters say has boosted the industry's strong growth nationwide. Some Washington state lawmakers have proposed scaling back the state's voter-approved renewable energy standards, and a California law imposing the strictest such standards in the country also requires more of that energy to be generated there, instead of being imported from the Northwest.

Perhaps most significant is last spring's unresolved dispute, when heavy runoff produced too much hydroelectric power for the grid to handle and BPA ordered wind producers to shut down.

BPA, the Portland, Ore. based federal agency that regulates much of the region's power transmission, has since proposed to pay half the losses incurred by wind power producers that are forced to shut down during periods of oversupply. The wind industry has said the proposal doesn't go far enough to protect them.

Wright said that while he isn't hoping for a dry winter _ "not even oversupply would cause me to do that" _ the current water supply forecast makes it unlikely those conditions will recur this year.

The issues together are slowing development in the region, said Cameron Yourkowski, senior policy manager for the advocacy group Renewable Northwest Project.

"Just the specter of all these issues provides an immediate-term drag on projects that would be developed over the next year and have to make business decisions now and can't do that because of the policy uncertainty," he said.

But, he added, "if we do get favorable resolution of those issues, then hopefully this dip in development and interest in general won't last too long."

The group has proposed renewables as an economic development driver, particularly in rural communities.

In Paterson, Wash., a town overlooking the Columbia River about 140 miles east of Portland, construction of the transmission line was a boon for business. Jessica Crow, owner of the Paterson Store and Restaurant, awoke at 4:30 each morning to make breakfast burritos for the construction crews.

"It was great for business, since we're the only restaurant here, and they were a great bunch to work with," she said. "We enjoyed them very much."

11.1 Is BC Hydro aware of the development of this transmission line? If yes are there any lessons that can be learned with respect to the development of transmission lines by BC Hydro?

12.0 Topic: Capital Expenditures and Additions: Site C, Deferral Accounts: Site C

Reference: Exhibit B-15, BC Hydro response to BCUC IR 1.454.2, and Exhibit B-16, BC Hydro response to AMPC IR 1.25.1

In its response to AMPC IR 1.25.1, BC Hydro states: *"The $87 to $95 per megawatt hour costs are*

levelized unit energy costs."

12.1 What are the assumptions resulting in the $87 cost vs. the $95 cost?

12.2 Are these costs as at the plant gate or delivered to the Lower Mainland?

12.3 What are the cost of the losses, CIFT, and Network Upgrades required to get this power to the Lower Mainland?

12.4 Are these costs levelized over all the energy from Site C (5,100 GWh/yr) or only over the Firm energy (4,700 GWh/yr) as is done for IPPs?

In its response to BCUC IR 1.454.2, BC Hydro states in part: "The $129/MWh (F2011$) is the average levelized Clean Power Call firm energy price, which is adjusted for delivery to the Lower Mainland (including transmission losses) and other factors.

12.5 Please describe in detail the "other factors"..

12.6 If costs for Site C are expressed to be as at the plant gate, then what is the levelized unit energy costs (F2011$) for Site C for firm energy delivered to the Lower Mainland (including transmission losses) and other factors?

13.0 Topic: Capital Expenditures and Additions

Reference: Exhibit B-15, BC Hydro response to BCUC IR 1.200.1.1

13.1 Given that the Bridge River System has been in operation for over 50 years, why is the hydrology of this system being reviewed?

14.0 Topic: Subsidiary Net Income (Powerex) & Allocation of PTP Charges to Powerex

Reference: Exhibit B-15, BC Hydro response to BCUC IR 1.333.2.3, and Exhibit B-16, BC Hydro response to AMPC IR 1.19.1

14.1 Will the shape of the load profile continue to change in the same manner as the natural gas/LNG industry expands and develops in B.C.? As the mining industry develops in the northwest? As the existing transmission bottleneck between Terrace and Kitimat is alleviated allowing greater interchange of electricity between Rio Tinto Alcan and BC Hydro with respect to the electricity required for Rio Tinto Alcan's aluminum smelter in Kitimat?

15.0 Topic: Subsidiary Net Income (Powerex) & Allocation of PTP Charges to Powerex

Reference: Exhibit B-15, BC Hydro response to BCUC IR 1.333.2.3,.and Exhibit B-16, BC Hydro response to AMPC IR 1.19.1

According to media reports, electricity pool prices in Alberta have, at times, been very high because demand has outstripped supply.

15.1 What is the maximum transfer capacity of the B.C. Alberta 500 kV intertie without any derating?

15.2 What is its current transfer capacity after any derating?

15.3 Will there be any further derating because of the development of a 230 kV transmission line

between Alberta and Montana?

15.4 Has Powerex's ability to maximize its revenue been constrained because of any derating of the B.C. Alberta intertie?

15.5 Will it be further constrained by any derating associated with the 230 kV transmission line between Alberta and Montana?

15.6 What can be done to prevent any derating because of the Alberta Montana line? What can be done to restore it to the level it would have been but for existing derating other than any derating associated with the Alberta Montana line?

16.0 Topic: Subsidiary Net Income (Powerex) & Allocation of PTP Charges to Powerex

Reference: Exhibit B-1-3, Page 8-11

16.1 Assuming that BC Hydro/Powerex do not receive any of the relief they are seeking with respect to the implementation of the California Cap and Trade system, what will the impact be on Powerex's net income commencing January 1, 2013 until the end of the text period? Again assuming no relief, please provide the details of the impacts.

17.0 Topic: Storage and Inflow Forecast

Reference: Exhibit B-1-3, Page 4-13

17.1 Please explain how the ageing of BC Hydro's generating assets is taken into account in the calculation of average system inflow energy equivalent ?

17.2 What Resource Smart project additions will increase the inflow energy equivalent?

17.3 How is the purchase of Waneta reflected in the inflow energy equivalent?

17.4 What improvements in modeling have been made and what is the impact on inflow energy equivalent?

17.5 What changes in operating constraints been made and what is the impact on inflow energy equivalent?

18.0 Topic: Demand Side Management

Reference: Other BC Hydro reports

18.1 Please provide copies of any "CEO and Executive Committee reports to the Board of Directors" during the past 5 years which reported on DSM plans or results.

18.2 Please provide copies of any "Quarterly Performance reports" to the Board of Directors during the past 2 years which reported on DSM plans or results.

19.0 Topic: Demand Side Management

Reference: Exhibit B-16, response to CEBC IR 1.14.1 and 1.14.3, and Exhibit B-15, response to BCUC IR 1.446.3

CEBC requested the Excel models of the tables in Appendix II, Attachment 5 *"with all the calculation formulas intact, so that the user can follow how the calculations are being done."* The BCUC staff also requested the *"10 tables in Attachment 5 as working Excel spreadsheets, including formulas and all supporting details."*

BC Hydro supplied the Excel models in a partly working condition. Many of the values are still merely pasted values which do not give any insight into how those values are calculated. For instance, in the sheet "Avoid Nat Gas Cost", the values are pasted present value dollars. These values are presumably derived from a quantity times a price times a present value factor.

19.1 For completeness and understanding, please provide the data input tables at least as far as the quantities, price assumptions and present value factors that are being used in the present value dollar calculations. These values must have been in the original models, so please include the sheets that have the original quantities, prices, and present value factors, rather than going to the additional trouble of deleting them. They are needed to complete our understanding.

19.2 In the specific sheet mentioned above, "Avoid Nat Gas Cost", the values for the Refrigerator Buy-back program for 2012 and 2013 are -1,149 and -1,267 (PV F2011 $000), which are values that are less than 10% different. However, in the example model for the same Refrigerator Buy-back program, given as an attachment to CEBC IR 1.15.3, the Acquired Gas Savings at the meter (in GJs) is shown as 14,229 for F2012 and 32,853 for F2013, which are values that are more than 2:1 in ratio. How can these two versions of the additional gas requirements possible be describing the same program? What is responsible for the difference between them?

20.0 Topic: Demand Side Management

Reference: Exhibit B-16, response to CEBC IR 1.14.2.2, and Exhibit B-15, response to BCUC IR 1.446.3

CEBC requested an explanation of the derivation of the non-electrical energy benefits and BC Hydro's response referred to BCUC IR 1.446.3. However, this BCUC IR does not include any discussion as to how the non-energy benefits are determined.

20.1 Please provide a discussion as to which programs include the non-energy benefits, what those benefits consist of and how they are quantified.

21.0 Topic: Demand Side Management

Reference: Exhibit B-16, response to CEBC IR 1.15.1 and 1.15.2, re DSM assumptions

CEBC requested and BC Hydro provided a table showing the ranges for a number of key assumptions used in the valuation of residential, commercial, and industrial DSM programs. These assumptions included Persistence, Free Riders, Free Drivers, Market Effects, Direct Rebound, and Cross Effects.

21.1 Please provide the definitions for these assumptions as employed by BC Hydro and the definitions that are employed by the California Standard Practices Manual. Please explain any significant differences.

In IR 1.15.2.1, CEBC requested any studies or reports used to estimate or substantiate those assumptions for a number of specified programs. BC Hydro provided a brief description, stating that *"The development of program-specific assumptions is not an exact science and requires judgment on the part of program managers… further informed by a variety of information sources."* BC Hydro also provided several Attachments giving more complete descriptions of methodology.

21.2 Included in the attachments were two Power Smart Standard documents dealing in depth with Rebound Effects and Persistence. Are there any other such Power Smart Standard documents dealing with other assumptions that are key to performance forecasting and evaluation? If so, please provide copies of those additional documents.

21.3 Attachment 1, "Power Smart Standard: Rebound Effects" describes the tendency of consumers to increase their energy consumption after implementing energy efficiency savings. This would include the phenomenon of people leaving their lights on longer once they install lower wattage bulbs, and people replacing 100 lights on a Christmas tree with 500 to 700 LED lights on the same size tree. Please confirm that BC Hydro sometimes refers to this as "Takeback". Are these two terms interchangeable?

21.4 In Attachment 1, BC Hydro quantifies the Direct Rebound at 0% for most programs except for a tendency of low income people to turn up their thermostats when their heating bills fall as a result of efficiencies. To help better understand the methodology involved in measuring Rebound, please provide copies of the 3 studies cited in the references as:

(1) Research in Action (13 May 2011) Summary of Findings: Rebound Effect.
(2) BC Hydro Power Smart, Quality Assurance (21 March 2011) Literature Review of Direct, Indirect, and Economy-Wide Rebound Effects; and
(9) BC Hydro Power Smart, Quality Assurance (8 June 2011), Indirect Rebound Effects.

21.5 Attachment 1 also states that BC Hydro *"developed a DSM Policy on Expanded Facilities and Production (reference 7) as well as a framework for assessing the DSM savings reporting eligibility of projects that may result in a plant expansion or production increases (reference 8). These tools are used to avoid direct rebound in the industrial process end-use."* Please also provide copies of these two references (7) and (8).

21.6 Please also provide a copy of reference (5) to Attachment 1: Sampson Research (7 October 2004) Residential Lighting Hours-Of-Use Study.

22.0 Topic: Demand Side Management

Reference: Exhibit B-16, response to CEBC IR 1.15.2.1, Attachment 6, re DSM cross effects assumption for CFL lighting.

BC Hydro also provided Attachment 7, Milestone Report: Lighting Program – CFL Component Evaluation for F2009 (September 28, 2009). In Appendix A (page 29 of 39) it states, *"Cross effects is defined as share of energy savings lost due to interactive effects of lighting saving and electric space heating."* The Appendix goes on to calculate a cross effects factor by multiplying: 1) the percentage of CFLs installed indoors (89%), times 2) the average percentage of electrically heated accounts for BC Hydro (36%, REUS 2008), times 3) the coincident rate of lighting in heating months (68%), times 4) the Heat Loss factor (75%), to give an overall cross effects factor of 16%.

22.1 What is the current percentage of CFLs installed indoors? What is REUS 2008, and what is the current percentage of electrically heated accounts for BC Hydro?

22.2 The Appendix states that, *"Heat loss factor takes into account the share of energy loss as heat of one bulb."* What exactly does this statement mean and what is the scientific justification for that 75% value?

22.3 Please confirm that the cross effects defined in this way will only include the cross effects for electrically heated accounts (i.e. the calculated factor of 16% only includes electrically heated homes). How does BC Hydro account for the majority of homes that are heated by gas or other fossil fuels? Please provide the calculations for the increased fuel use in non-electrically heated homes.

22.4 Is this a standard definition of cross effects (i.e. including only the cross effects for electrical heating), or is this definition customized by BC Hydro?

23.0 Topic: Demand Side Management

Reference: Exhibit B-16, response to CEBC IR 1.15.3, re DSM assumptions and the modeling of unit energy costs

CEBC requested a working Excel model that shows the calculation of the unit energy costs for a variety of residential, commercial and industrial DSM programs. BC Hydro stated that, *"The levelized costs in the Updated DSM Plan were calculated in a software application that cannot be replicated in Excel."* However, BC Hydro did provide a model which calculates the levelized costs of the Refrigerator Buy Back program's activity in F2012 and F2013.

23.1 In the Refrigerator Buy Back program, please explain how the Free Ridership is determined to be 21% and Free Drivers 6.7%. In the F11 RRA, the Free Riders were stated to be 24-39%, and in the 2008 LTAP, it was as high as 60%. Why is the determination of Free Ridership so volatile? Please provide any studies or surveys that have been done to determine the current ratios?

23.2 Similarly, how are the cross effects determined to be 8.6% and the annual gas per participant to be -0.72 GJ/yr.? What gas price is assumed in valuing the incremental gas consumption?

23.3 Why are the annual savings per participant 726.3 kWh in F2012 and only 692.1 kWh in F2013? What happens to this savings in future years?