REQUESTOR NAME: Canadian Office and Professional Employees Union, Local 378 (COPE 378)

INFORMATION REQUEST ROUND NO: 2

TO: BRITISH COLUMBIA HYDRO & POWER AUTHORITY

DATE: MARCH 6, 2012

PROJECT NO. 3698622/Order G-40-11

APPLICATION NAME: F2012 to F2014 Revenue Requirements Application

TOPIC: BC HYDRO REVIEW PANEL

2.64 The Review Panel describes its approach as follows:

> The panel was supported by a multi-disciplinary team who, with the support of expert consultants, conducted a broad scan of BC Hydro, and performed in depth work where they observed gaps, had possible concerns or identified opportunities for improvement.
>
> The team included up to 20 professionals, mostly working on-site at BC Hydro for almost seven weeks. BC Hydro executive, management and staff provided utmost cooperation and support, which was essential in completing the review in the short timeframe. The approach included:
>
> - the review of relevant legislation, contracts, agreements and other documentation;
> - interviews and consultation (sic) senior company executives, BC Hydro staff, the province and other stakeholders;
> - research for comparable information from other relevant organizations and other jurisdictions; and
> - review of recent annual reports of the entity and comparators.
>
> (Appendix BB, p. 27 OF 133)

QUESTION:

2.64.1 Please file copies of the documents or studies which were prepared by BC Hydro, the multi-disciplinary team or the expert consultants for the purposes of the work of the Review Committee that addressed the issues covered in pages 40 to 60 of the report, including:

- staffing levels;
- management to employee ratios;
- numbers of engineers required;
- a "reasonable level" of employees of 4,800;
- overtime;
- variable pay; and
- post-retirement benefits.

We expect that potentially there could be a very large quantity of documents covered by this question, including documents already on the public record, and spreadsheets and other materials whose useful contents are summarized or captured elsewhere. We are not expecting BC Hydro to produce a large volume of documents in response to this question, but rather to produce the documents which are the most useful, in the sense that they provide the sought-after information in the most efficient manner. We welcome discussions with COPE 378's counsel if further clarification of the extent of discovery would be helpful.

TOPIC: TRADE INCOME

2.65 BC Hydro's March 2011 presentation to various rating agencies included the following statement:

"Over the previous five years, Powerex (PX) income has ranged from $12 to $259 million. Market and economic conditions, recovery expectations, reduced BCH system flexibility and the strength of the C$ dollar may materially impact PX and its ability to achieve net income at the same level as in recent years for the foreseeable future. The estimated average annual net income is $50 to $100 million over the F2011 - F2014 period.

"In response, PX is looking at opportunities for longer term energy transactions that can create long-term economic value including long-term renewable transactions to

continue to build upon our renewable energy portfolio. Additionally, PX has been pursuing multiple paths to advance exports of B.C. clean energy"

(Exhibit B-16, COPE 378 IR 1.63.2, Attachment 1).

QUESTIONS:

2.65.1 Please reconcile the above statement, which seems to accord with the forecasts of Trade Income in the original application, with the decision to increase the forecasts in the Amended Application.

2.65.2 Has PX been successful in leveraging the benefits of "our renewable energy portfolio"?

2.66 COPE378's IR 1.32.1 "[G]iven the lack of close relation to water inflows, has BC Hydro considered alternative methods of crediting its cost of service with the amounts of Trade Income to which the Heritage Contract may entitle it, from time to time?" was probably misinterpreted by BC Hydro. Accordingly it is reworded as follows:

2.66.1 "Does BC Hydro consider that a more rational approach would be to set rates on the basis of Trade Income being zero each year, and to refund to customers the actual trade income as a credit to customers' bills in the following year? In this manner, BC Hydro would not have to collect from its customers credits to which they were never entitled".

2.67 **reference: ATTACHMENT 1, California Air Resources Board, California Cap-and-Trade Program, Resolution 11.32, October 20, 2011, numbered para. 2, top of p. 11**

2 .67.1 Please confirm that Attachment 1 is a resolution adopted by the California Air Resources Board.

2 .67.2 Please explain the manner in which the California authorities regard BC Hydro and Powerex to practice "resource shuffling" for the purposes of their Cap-and-Trade Program.

2 .67.3 Please describe the impact of any determination by the California authorities that BC Hydro and Powerex are "resource shuffling" upon the pricing and competitiveness of electricity exported from British Columbia into the California market. Please differentiate between the impact on electricity BC Hydro or Powerex might seek to sell as "green", "clean" or otherwise premium-priced energy, and electricity which is priced on the same footing as hydrocarbon-sourced energy.

2 .67.4 Please confirm that BC Hydro did not take this development into account when it finalized the Amended Application in this proceeding. If it was taken into account, please indicate where, in what manner, and to what extent.

2 .67.5 Please comment on the potential impact of this development upon BC Hydro's trade income during the test period as projected in the Amended Application; if BC Hydro does not consider that this development will have a negative impact please explain that conclusion fully.

ATTACHMENT 1

COPE 378 IR 2.67

California Air Resources Board

California Cap-and-Trade Program

Resolution 11.32

October 20, 2011

State of California
AIR RESOURCES BOARD

California Cap-and-Trade Program
Resolution 11-32

October 20, 2011

Agenda Item No.: 11-8-1

WHEREAS, sections 39600 and 39601 of the Health and Safety Code authorize the Air Resources Board (ARB or Board) to adopt standards, rules, and regulations and to do such acts as may be necessary for the proper execution of the powers and duties granted to and imposed upon the Board by law;

WHEREAS, the California Global Warming Solutions Act of 2006 (AB 32; Chapter 488, Statutes of 2006; Health and Safety Code section 38500 et seq.) declares that global warming poses a serious threat to the economic well-being, public health, natural resources, and environment of California and creates a comprehensive multi-year program to reduce California's greenhouse gas (GHG) emissions to 1990 levels by 2020;

WHEREAS, AB 32 added section 38501 to the Health and Safety Code, which expresses the Legislature's intent that ARB coordinate with State agencies and consult with the environmental justice community, industry sectors, business groups, academic institutions, environmental organizations, and other stakeholders in implementing AB 32; and design emissions reduction measures to meet the statewide emissions limits for greenhouse gases in a manner that minimizes costs and maximizes benefits for California's economy, maximizes additional environmental and economic co-benefits for California, and complements the State's efforts to improve air quality;

WHEREAS, section 38501(c) of the Health and Safety Code declares that California has long been a national and international leader on energy conservation and environmental stewardship efforts, and the program established pursuant to AB 32 will continue this tradition of environmental leadership by placing California at the forefront of national and international efforts to reduce GHG emissions;

WHEREAS, section 38501(d) of the Health and Safety Code confirms that national and international actions are necessary to fully address the issue of global warming, but action taken by California to reduce GHG emissions will have far reaching effects by encouraging other states, the federal government, and other countries to act;

WHEREAS, section 38510 of the Health and Safety Code designates ARB as the State agency charged with monitoring and regulating sources of GHG emissions in order to reduce these emissions;

WHEREAS, section 38560 of the Health and Safety Code directs ARB to adopt rules and regulations in an open public process to achieve the maximum technologically feasible and cost-effective GHG emissions reductions from sources or categories of sources;

WHEREAS, section 38562 of the Health and Safety Code requires ARB to adopt GHG emissions limits and emissions reduction measures by regulation to achieve the maximum technologically feasible and cost-effective reductions in GHG emissions in furtherance of achieving the statewide GHG emissions limit, to become operative beginning on January 1, 2012;

WHEREAS, section 38562 of the Health and Safety Code requires ARB, to the extent feasible and in furtherance of achieving the statewide GHG emissions limit, to do all of the following:

> Design the regulations, including distribution of emissions allowances where appropriate, in a manner that is equitable, seeks to minimize costs and maximize total benefits to California, and encourages early action to reduce GHG emissions;
>
> Ensure that activities undertaken to comply with the regulations do not disproportionately impact low-income communities;
>
> Ensure that entities that have voluntarily reduced their GHG emissions prior to the implementation of this section receive appropriate credit for early voluntary reductions;
>
> Ensure that activities undertaken pursuant to the regulations complement, and do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions;
>
> Consider cost-effectiveness of these regulations;
>
> Consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health;
>
> Minimize the administrative burden of implementing and complying with these regulations;
>
> Minimize leakage; and

Consider the significance of the contribution of each source or category of sources to statewide emissions of greenhouse gases.

WHEREAS, sections 38562(c) and 38570 of the Health and Safety Code authorize ARB to adopt regulations that utilize market-based compliance mechanisms;

WHEREAS, section 38570 of the Health and Safety Code also directs ARB, to the extent feasible and in furtherance of achieving the statewide GHG emissions limit, to do all of the following before including any market-based compliance mechanism in the regulations:

Consider the potential for direct, indirect, and cumulative emissions impacts from these mechanisms, including localized impacts in communities that are already adversely impacted by air pollution;

Design any market-based compliance mechanism to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants; and

Maximize additional environmental and economic benefits for California, as appropriate.

WHEREAS, section 38570(c) of the Health and Safety Code further directs ARB to adopt regulations governing how market-based compliance mechanisms may be used by regulated entities subject to GHG emissions limits and mandatory emissions reporting requirements to achieve compliance with their GHG emissions limits;

WHEREAS, section 38571 of the Health and Safety Code directs ARB to adopt methodologies for the quantification of voluntary GHG emissions reductions and regulations to verify and enforce any voluntary GHG emissions reductions that are authorized by ARB for use to comply with GHG emissions limits established by ARB; the adoption of methodologies is exempt from the rulemaking provisions of the Administrative Procedure Act;

WHEREAS, California is participating in the Western Climate Initiative (WCI), with several Canadian Partner jurisdictions considering implementing GHG cap-and-trade programs and formally linking them to form a regional market for compliance instruments;

WHEREAS, by linking California's program to WCI Partner jurisdictions, the combined programs will result in more emission reductions, generate greater potential for lower cost emissions reductions, enhance market liquidity, and will likely reduce the compliance costs of covered sources more than could be realized through a California-only program;

WHEREAS, establishing and implementing a California and regional GHG cap-and-trade program requires ARB and WCI Partner jurisdictions to harmonize a number of

specific regulatory and operational provisions, including, but not limited to, sources subject to compliance obligations, cost-containment mechanisms, evaluation of regulatory baselines for existing offset protocols, procedures for developing new offset protocols, market tracking system development and operation, auction services, financial services, and market monitoring and oversight;

WHEREAS, ARB and the WCI Partner jurisdictions are working towards establishing a Regional Administrative Organization similar to other established cap-and-trade programs (e.g., Regional Greenhouse Gas Initiative) to meet the goal of regionally coordinated administration of cap-and-trade services;

WHEREAS, staff has completed a Final Regulation Order establishing a GHG cap-and-trade program for California; the regulation is set forth in Attachment A hereto and includes the following elements:

Addresses emissions of carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6), and nitrogen trifluoride (NF_3);

Identifies the program scope: starting in 2012, electricity, including imports, and large (emissions >25,000 metric tons carbon dioxide per year) industrial facilities are included; starting in 2015, distributors of transportation fuels, natural gas, and other fuels are included;

Establishes a declining aggregated emissions cap on included sectors. The cap starts at 162.8 million allowances in 2013, which is equal to the emissions forecast for that year. The cap declines approximately 2 percent per year in the initial period (2013–2014). In 2015, the cap increases to 394.5 million allowances to account for the expansion in program scope to include fuel suppliers. The cap declines at approximately 3 percent per year between 2015 and 2020. The 2020 cap is set at 334.2 million allowances;

Provides for distribution of allowances through a mix of direct allocation and auction in a system designed to reward early action and investment in energy efficiency and GHG emissions reductions; allowances will be distributed for the purposes of price containment, industry transition and assistance, and fulfillment of AB 32 statutory objectives;

Establishes a market platform for allowance auction and sale;

Establishes cost-containment mechanisms and market flexibility mechanisms, including trading of allowances and offsets, allowance banking, a two year compliance period and two 3-year compliance periods, the ability to use offsets for up to 8 percent of an entity's compliance obligation, and an allowance reserve that provides allowances at fixed prices to those with compliance obligations;

Establishes a mechanism to link with other GHG trading programs and approve the use of compliance instruments issued by a linked external GHG trading program;

Establishes requirements and procedures for ARB to issue offset credits according to offset protocols adopted by the Board;

Includes four offset protocols to be considered for adoption by the Board as part of this regulatory package;

Establishes a mechanism to include international offset programs from an entire sector within a region;

Establishes a robust enforcement mechanism that will discourage gaming of the system and deter and vigorously punish fraudulent activities; and

Provides an opt-in provision for entities whose annual GHG emissions are below the threshold to voluntarily participate in this program.

WHEREAS, staff conducted over forty public workshops regarding the Final Regulation Order during the period 2008–2011, and also participated in numerous other meetings with various stakeholders to provide additional opportunities to participate in the regulatory development process;

WHEREAS, the Board has considered the community impacts of the Final Regulation Order, including environmental justice concerns;

WHEREAS, staff had prepared a document entitled “Staff Report: Initial Statement of Reasons for Proposed Regulation to Implement the California Cap-and-Trade Program” (ISOR), which presents the rationale and basis for the Final Regulation Order and identifies the data, reports, and information relied upon;

WHEREAS, public hearings and other administrative proceedings were held in accordance with the provisions of Chapter 3.5 (commencing with section 11340), part 1, division 3, title 2 of the Government Code;

WHEREAS, the Final Regulation Order was made available to the public at least 10 days prior to the public hearing to consider the Final Regulation Order;

WHEREAS, in consideration of the Final Regulation Order, written comments, and public testimony it has received to date, the Board finds that:

GHG emissions associated with entities covered by the cap-and-trade regulation account for about 85 percent of GHG emissions in the State;

Covered entities can reduce emissions to comply with the cap-and-trade regulation using a variety of currently available GHG reduction strategies, including those complementary measures identified in the Scoping Plan;

In addition to the complementary measures identified in the Scoping Plan, the cap-and-trade regulation is expected to significantly reduce GHG emissions. The cap-and-trade regulation will ensure GHG emissions levels in 2020 are equal to 1990 levels;

The cap-and-trade regulation was developed using the best available economic and scientific information and will achieve the maximum technologically feasible and cost-effective GHG emissions reductions from covered entities and offset projects;

The GHG emissions reductions resulting from the implementation of the cap-and-trade regulation are expected to be real, permanent, quantifiable, verifiable, and enforceable by ARB, and the cap-and-trade regulation complements and does not interfere with other air quality efforts;

The cap-and-trade regulation meets the statutory requirements identified in section 38562 of the Health and Safety Code;

The cap-and-trade regulation meets the statutory requirements for a market-based mechanism identified in section 38570 of the Health and Safety Code;

The cap-and-trade regulation was developed in an open public process, in consultation with affected parties, through numerous public workshops, individual meetings, and other outreach efforts;

The cap-and-trade regulation is predicated on GHG regulations that are clear, consistent, enforceable, and transparent and helps meet the goals of AB 32;

The benefits to human health, public safety, public welfare, or the environment justify the costs of the cap-and-trade regulation;

The cost-effectiveness of the cap-and-trade regulation has been considered, and the regulation will achieve cost-effective GHG emissions reductions;

The cap-and-trade regulation is consistent with ARB's environmental justice policies and will equally benefit residents of any race, culture, or income level;

Robust reporting and verification requirements associated with the cap-and-trade regulation are necessary for the health, safety, and welfare of the people of the State; and

No reasonable alternative considered, or that has otherwise been identified and brought to the attention of ARB, would be more effective at carrying out the purpose for which the regulation is proposed or would be as effective and less burdensome to affected entities than the proposed regulation.

WHEREAS, the Board further finds that:

The integrity of offsets is critical to the success of a cap-and-trade program; It is in the interest of the State of California to pursue a comprehensive approach that aligns the incentives provided by AB 32 programs, including the cap-and-trade regulation, with statewide policy for handling solid waste, including recycling, remanufacturing of recovered materials in state, composting and anaerobic digestion, waste-to-energy facilities, landfilling, and the treatment of biomass;

Electricity rates should create the appropriate incentives for electricity conservation, greenhouse gas efficient technologies, and efficient distributed electricity generation such as combined heat and power;

Carbon pricing is an important function of the cap-and-trade regulation, and that it is equally important that if allowance value provided to electric distribution utilities for ratepayer benefit is returned directly to customers it is consistent with State efforts to promote energy efficiency and energy conservation;

Incentives created by the cap-and-trade program should motivate investment and innovation in clean technology;

The cap-and-trade regulation will establish a greenhouse gas market that allows business flexibility to comply with the regulation while also ensuring strong oversight and transparency;

State universities serve an important public service in providing affordable higher education;

Water rates should create the appropriate incentives for water conservation, greenhouse gas efficient technologies, and the efficient supply and use of water;

Carbon pricing is an important function of the cap-and-trade regulation, and that it is equally important that if allowance value is used for the benefit of water ratepayers it is used consistent with State efforts to promote efficient use and supply of water and water conservation; and

The cap-and-trade program should properly account for the emissions associated with generation and transmission of both in-State and imported electricity in accordance with AB 32.

WHEREAS, at a public hearing held December 16, 2010, the Board considered the proposed regulations for sections 95800 to 96023, title 17, California Code of Regulations (CCR). The Board considered the ISOR released on October 28, 2010, and adopted Resolution 10-42 directing several modifications proposed by staff and guidance on implementation. The Board advised staff that additional changes were necessary. As a result, on July 25, 2011, the first Notice of Public Availability of Modified Text and Availability of Additional Documents (1st 15-Day Change Notice) was issued. The public comment period for the 1st 15-Day Change Notice ended at 5:00 p.m. on August 11, 2011;

WHEREAS, additional modifications to the regulatory text were proposed in a Second Notice of Public Availability of Modified Text (2nd 15-Day Change Notice). The additional modifications addressed comments ARB staff received in the first 15-day Change Notice and were the result of additional staff analysis and stakeholder engagement. The 2nd 15-Day Change Notice was posted September 12, 2011. The public comment period for the 2nd 15-Day Change Notice ended at 5:00 p.m. on September 27, 2011;

WHEREAS, in the Final Statement of Reasons, staff is preparing responses to comments received on the record during the initial 45-day comment period, comments presented at the December 16, 2010 Board hearing both orally and in writing, comments received during the first 15-day Change Notice released July 25, 2011, and the comments received during second 15-Day Change Notice released September 12, 2011;

WHEREAS, ARB has a regulatory program certified under Public Resources Code section 21080.5, and pursuant to this program ARB conducts environmental analyses to meet the requirements of the California Environmental Quality Act (CEQA);

WHEREAS, ARB staff prepared an environmental analysis for the cap-and-trade regulation pursuant to its certified regulatory program; this analysis is contained in the Functional Equivalent Document (FED) in Appendix O to the ISOR;

WHEREAS, the FED, which sets forth a programmatic analysis of the potential environmental impacts associated with the cap-and-trade regulation and the offset protocols, including potential alternatives to the regulation, was released for public review on October 28, 2010, with a 45-day written comment period from November 1, 2010 to December 16, 2010;

WHEREAS, in Resolution 10-42, the Board also directed the Executive Officer to complete the regulatory modifications and the environmental review process in accordance with the requirements of the Administrative Procedure Act and CEQA under ARB's certified regulatory program, and to either take final action to adopt the proposed regulation or return the matter to the Board for further consideration;

WHEREAS, ARB received written comments on the potential environmental impacts of the cap-and-trade regulation during the initial 45-day public comment period, and the two subsequent 15-day comment periods associated with the two Notices of Public Availability of Modified Text;

WHEREAS, ARB staff has reviewed the written comments on the potential environmental impacts received during the comment periods and prepared written responses to these comments;

WHEREAS, on October 10, 2011, ARB released a document called the *Response to Comments on the Functional Equivalent Document Prepared for the California Cap on GHG Emissions and Market-Based Compliance Mechanisms* (Response to FED Comments) which includes a summary of written comments received on the FED that raise significant environmental issues and staff's written responses as set forth in Attachment B to this Resolution;

WHEREAS, in the FED, ARB committed to pursue an adaptive management approach to monitor and respond as appropriate to address unanticipated, adverse, localized air quality impacts and impacts from the U.S. Forest Protocol on special states, species, sensitive habitats, and federally protected wetlands as part of the implementation of the cap-and-trade regulation and the U.S. Forest Protocol;

WHEREAS, on October 10, 2011, ARB released the proposed *Adaptive Management Plan for the Cap-and-Trade Regulation* (Adaptive Management Plan) that describes ARB's commitment and process to monitor for unanticipated and unintended adverse impacts related to localized air quality resulting from implementation of the cap-and-trade regulation and adverse forestry impacts from implementation of the U.S. Forest Protocol, and ARB's commitment to developing and implementing appropriate actions to address any impacts identified as set forth in Attachment C to this Resolution;

WHEREAS, ARB has the authority under sections 39600, 39601, and 38500 et seq. of the Health and Safety Code to adopt standards, rules and regulations to address unanticipated and unintended adverse impacts related to localized air quality resulting from implementation of the cap-and-trade regulation and adverse forestry impacts from implementation of the U.S. Forest Protocol;

WHEREAS, at a duly noticed public hearing held on October 20**,** 2011, staff presented the Response to FED Comments and the Adaptive Management Plan for Board for approval, and the Final Regulation Order for adoption;

WHEREAS, the Board has reviewed and considered the FED, the Response to FED Comments, and the Adaptive Management Plan;

WHEREAS, CEQA and ARB's certified regulatory program require that before taking final action on any proposal for which significant environmental comments have been raised, the decision maker must approve a written response to each such comment; and

WHEREAS, CEQA and ARB's certified regulatory program require that any proposal for which significant adverse environmental impacts have been identified during the review process shall not be approved if there are feasible mitigation measures or feasible alternatives which would substantially reduce such adverse impacts.

NOW, THEREFORE, BE IT RESOLVED that the Board hereby certifies that the FED was completed in compliance with CEQA under ARB's certified regulatory program, reflects the agency's independent judgment and analysis, and was presented to the Board whose members reviewed, considered, and approved the information therein prior to acting on the proposed regulation.

BE IT FURTHER RESOLVED that the Board approves the written responses to comments raising significant environmental issues included in the Response to FED Comments.

BE IT FURTHER RESOLVED that in consideration of the FED and the Response to FED Comments, and in accordance with the requirements of CEQA and ARB's certified regulatory program, the Board adopts the Findings and Statement of Overriding Considerations as set forth in Attachment D to this Resolution.

BE IT FURTHER RESOLVED that the Board approves the *Adaptive Management Plan for the Cap-and-Trade Regulation*.

BE IT FURTHER RESOLVED that the Board adopts sections 95800 to 96023, title 17, California Code of Regulations (including the four compliance protocols incorporated by reference in the regulation: the Compliance Offset Protocols for Livestock Projects, Ozone Depleting Substances Projects, Urban Forest Projects, and U.S. Forest Projects) as set forth in Attachment A to this Resolution.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to finalize the FSOR and submit the rulemaking package to Office of Administrative Law by October 28, 2011.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to continue discussions with stakeholders to identify and propose, as necessary, during the initial implementation of the cap-and-trade program, potential amendments to the Regulation including, but not limited to the following areas:

1. Provisions to balance flexibility and accumulation of market power including auction frequency, and holding and purchase limits or other methods;

2. Definition of Resource Shuffling to: (a) provide appropriate incentives for accelerated divestiture of high-emitting resources by recognizing that these divestitures can further the goals of AB 32; and (b) ensure changes in reported emissions from imported electricity that serves California do not result merely in a shift of emissions within the Western Electricity Coordinating Council region, but reduces overall emissions;

3. Allocation of allowances for emissions associated with natural gas combustion emissions as written in section 95852 of the cap-and-trade regulation; and

4. Distribution of allowance value associated with cap-and-trade compliance costs from using electricity to supply water, and the expected ability of allowance allocation and other measures to adequately address the incidence of these costs equitably across regions of the State.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to continue to review information concerning the emissions intensity, trade exposure, and in-State competition of industries in California, and to recommend to the Board changes to the leakage risk determinations and allowance allocation approach, if needed, prior to the initial allocation of allowances for the first or second compliance period, as appropriate, for industries identified in Table 8-1 of the cap-and-trade regulation, including refineries and glass manufacturers.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to continue to work with stakeholders to further develop the allowance allocation approach for the petroleum refining sector and associated activities in the second and third compliance periods. This evaluation should include additional analysis of the Carbon Weighted Tonne approach and treatment of hydrogen production, coke calcining, and other activities that may operate under a variety of ownership structures.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to initiate a study to analyze the ability of the agricultural industry, including food processors, to pass on regulatory costs to consumers, given domestic and international competition and continually fluctuating global markets. The Executive Officer shall identify and propose regulatory amendments, as appropriate.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to identify and propose new benchmarks and allowance allocation for manufacturing of new products in California, as appropriate. The allowance allocation should incorporate efforts to minimize leakage.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to monitor protocol development and to propose technical updates to adopted protocols, as needed.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to develop implementation documents laying out the process for review and consideration of new offset protocols, including a description of how staff will evaluate additionality.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to continue to work with Cal/Recycle and other stakeholders to characterize lifecycle emissions reduction opportunities for different options for handling solid waste, including recycling, remanufacturing of recovered materials in state, composting and anaerobic digestion, waste-to-energy facilities, landfilling, and the treatment of biomass. The Executive Officer shall identify and propose regulatory amendments, as appropriate, so that AB 32 implementation, including the cap-and-trade regulation, aligns with statewide waste management goals, provides equitable treatment to all sectors involved in waste handling, and considers the best available information. The Executive Officer shall report to the Board on progress in summer of 2012.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to continue to evaluate the definition of position holders relative to railroads and other specific types of fueling operations, work with interested stakeholders, and propose modifications to the regulations as appropriate to become effective prior to the start of the second compliance period.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to coordinate with stakeholders to develop a mechanism to achieve GHG emission reductions from the national security/military sector (NAICS 92811) beginning January 1, 2014.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to coordinate with the State universities and stakeholders to evaluate options for compliance, with amendments to the regulation as appropriate, including options on the use of auction revenue and report back to the Board in summer of 2012.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to monitor progress on bilateral negotiations between counterparties with existing contracts that do not have a mechanism for recovery of carbon costs associated with cap-and-trade for industries receiving free allowances pursuant to Section 95891, and identify and propose a possible solution, if necessary. For fixed-price contracts between independent generators and Investor Owned Utilities, the Board further directs the Executive Officer to work with the California Public Utilities Commission (CPUC) to encourage resolution between contract counterparties.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with the CPUC and Publicly Owned Utilities to reflect the findings of the Board that the impact of the cap-and-trade regulation on electricity rates creates appropriate incentives to further the goals of AB 32.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with the CPUC and the Publicly Owned Utilities to reflect the finding of the Board that if

allowance value provided to the electric distribution utilities for ratepayer benefit is returned directly to customers, it is consistent with State efforts to promote energy efficiency and energy conservation.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with the CPUC, California Energy Commission, California Independent System Operator and stakeholders to evaluate requirements for first jurisdictional deliverers of electricity and to report back to the Board in summer of 2012.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to coordinate with the Market Surveillance Committee and stakeholders to evaluate the effectiveness of the cost containment provisions of this program, including the Allowance Price Containment Reserve, offsets, banking and the three-year compliance period.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to contract with an external entity and work closely with regulated entities and other stakeholders to evaluate potential market conditions, trading dynamics, the Allowance Price Containment Reserve, and other key design features of the program prior to the beginning of the compliance obligation on January 1, 2013. The Executive Officer will make recommendations for changes, if any, necessary to address potential market design issues that are identified by or from these evaluations.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to continue to coordinate with the Commodity Futures Trading Commission and California State Attorney General's office on market oversight of the program, including the possibility of tracking forward contracts for sales of allowances.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to develop recommendations for the appropriate use of auction revenue. These recommendations should consider the Board's direction in Resolution 10-42.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to partner with the air quality management districts and air pollution control districts in the implementation of the cap-and-trade regulation, including, but not limited to, an evaluation of the impacts of the cap-and-trade program on industrial source greenhouse gas permitting and implementation of the Adaptive Management Plan. The Board further directs the Executive Officer to report back periodically to the Board on the nature and extent of this Partnership with the first report due in the first quarter of calendar year 2012.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to continue working with the WCI Partner jurisdictions to harmonize the programs by developing appropriate regulatory amendments necessary to formally link the programs, developing appropriate policy and technical protocols necessary to effectively implement the jurisdictions' programs, and working toward the establishment of a Regional Administration Organization.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer, as described in Resolution 10-42, to update the Board at least annually on the status of the cap-and-trade program. These annual updates should include elements described in Resolution 10-42, as well as the following:

The effectiveness of the cap-and-trade program;

How the cap-and-trade program is stimulating investment and innovation in clean technology;

Shifts in transportation fuel use and supply;

The status of existing offset protocols, and potential new offset protocols that could be proposed to the Board;

The status of carbon capture and sequestration technology; and

Federal greenhouse gas activities, including federal equivalency for a State program.

I hereby certify that the above is a true and correct copy of Resolution 11-32, as adopted by the Air Resources Board.

Mary Alice Morency, Clerk of the Board

Resolution 11-32

October 20, 2010

Identification of Attachments to the Board Resolution

Attachment A: Final Regulation Order for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms, title 17, California Code of Regulations, section 95800 to 96023, including the four Final Compliance Offset Protocols.

Attachment B: Response to FED Comments as found at: http://www.arb.ca.gov/cc/capandtrade/fed/staff-responses.pdf

Attachment C: Adaptive Management Plan as found at: http://www.arb.ca.gov/cc/capandtrade/adaptive_management/plan.pdf

Attachment D: Findings and Statement of Overriding Considerations, distributed at the October 20, 2011 Board hearing.

TOPIC: RATE MANAGEMENT

Reduction of $819 million

2.68 BC Hydro states that "[T]hese reduced rate increases are the result of a reduction of $819 million in revenue requirements over the three year period F2012 to F2014, as reflected in New Table 1-A"(Exhibit B-1, p.1-13).

QUESTION:

2.68.1 Please provide a reconciliation of the $819 million with the data in Original and Amended Appendices A, and also provide details of either how the 13 individual amounts can be identified in Amended Appendix A or how they were calculated.

TOPIC: CAPITAL ADDITIONS

2.69 **Reference: Amended Application, s. 6.3.5, page 6-13:**

6.3.5 Reductions to F2012-F2014 Capital Additions

To achieve the level of rate increase BC Hydro agreed to propose as a result of the Government Review, capital additions over the test period have been reduced from the planned additions in the F12-F14 RRA. Planned capital additions in the Amended F12-F14 RRA are now $4,193 million (net of Customer Contributions in Aid and excluding DSM Additions and HPOP properties for resale) compared to $4,839 million in the original Application, for a net reduction of $646 million. In order to achieve this target, BC Hydro identified $800 million in reductions to capital projects and program additions, which were partially offset by $154 million in required additions that were inadvertently excluded from the original Application, resulting in the reduction of $646 million.

QUESTIONS:

2.69.1 Please confirm that all of the capital additions contemplated in the original Application represented necessary and beneficial expenditures which were believed to be required in order to maintain the provision of reliable, safe and affordable electricity to BC Hydro's ratepayers.

2.69.2 Please confirm that the necessity for the capital additions which will not proceed, as a result of the reduction described in the passage reproduced above, will not disappear nor diminish after the test period.

2.69.3 Please confirm that one of the major cost-drivers behind BC Hydro's rising revenue requirement, whether before, during or after the test period, is the necessity to increase capital investment for the maintenance and renewal of the utility's aging

assets, and to make up for inadequate investment in maintaining and renewing those assets over the past two decades.

TOPIC: NHDA

2.70 Section 7 of HC2 reads as follows:

> When regulating and setting rates for the authority, the commission:
>
> (a) must allow the authority to establish one or more accounts to reflect and record variances between
>
> (i) the heritage payment obligation and the authority's forecast of the heritage payment obligation, and
>
> (ii) the trade income and the authority's forecast of trade income,
>
> (b) may allow the authority to establish one or more other deferral accounts for other purposes.

QUESTIONS:

2.70.1 Please state whether, under s. 7(a)(i), the Commission "must allow" BC Hydro to transfer the following amounts to the NHDA: $65.9 million in F2012, $103.2 million in F2013, and $46.2 million in F2014. If not, please explain why not.

2.70.2 Please comment on the assertion that HC2 expressly forbids the Commission to approve such a transfer as it is clear that the heritage payment obligation referred to in s. 7(a)(i) is an actual or out-turn obligation, as opposed to a forecast of the obligation, with the variance being the difference between the one and the other, and not between two forecasts.

2.71 BC Hydro states in its presentation to the rating agencies:

"[I]n Dec. 2010, the BCUC approved the Negotiated Settlement Agreement on BCH's F2011 Revenue Requirement Application, which, while confirming the 6.11 per cent rate increase for F2011 for all customer classes, approved a one-time rate credit to customers of 4.71 per cent in January to March 2011."

(Exhibit B-16, COPE 378 IR 1.63.2, Attachment 1).

QUESTIONS:

2.71.1 Please confirm that this is the same credit as was described in para 23 of the NSA which states: "[T]he net impact on BC Hydro's F2011 revenue requirement of items

17 to 20, above, is $43.8 million, which shall be reflected in BC Hydro's rates as a 4.71 per cent credit applied to the charges payable under all other approved rates, except for the DARR, for the period from January 1, 2011 to March 31, 2011, inclusive".

2.71.2 Please confirm that the amount refunded to BC Hydro's customers in this period was $43.8 million and that during the same period the amount in the energy deferral accounts totaled almost $800 million, which amount included the transfer of $222.5 million of F2011 costs into the NHDA.

2.71.3 Please explain why BC Hydro chose to agree to refund cash to its customers when they collectively owed BC Hydro almost 20 times as much.

2.72 In its response to COPE 1.46.1 BC Hydro states: "The justification of crediting the $104 million [from theTotal Finance Charges regulatory account] to the revenue requirement in F2011 was to reduce the bill impact on customers in F2011".

QUESTIONS:

2.72.1 Please calculate what the rate increase would have been in F2011 had BC Hydro not done the following:

- transferred $222.5 million "Baseline Adjustment" to the NHDA;
- refunded $43.8 million to its customers; and
- credited the $104 million to the NHDA.

2.72.2 Similarly, please calculate what the balance would be in the NHDA at the end of F2011.

TOPIC: CAPITAL STRUCTURE

2.73.1 Please confirm that BC Hydro issued or plans to issue the following amounts of long-term debt in the period F2007 to F2014.

Year	Amount ($million)
F2007	300
F2008	830
F2009	351.6
F2010	2070
F2011	500
F2012(E)	1,450
F2013(E)	1,725
F2014(E)	1,475

(Source: Amended Appendix A, Tab 8)

2.73.2 Please state the tenor and coupon of the issues actually made to date and the forecast coupon and tenor (i.e., the initial term to maturity) of the issues in the test period.

TOPIC: SHORT TERM BORROWINGS

2.74.1 Please confirm that the expressions "short term borrowings" in the Original and Amended Applications, "revolving borrowings" in BC Hydro's annual reports and "the Province's commercial paper (CP) borrowing program" in the presentation to the rating agencies are all the same thing.

2.74.2 Please explain BC Hydro's statement in the presentation to the rating agencies that "BCH's access to the Province's commercial paper (CP) borrowing program is currently C$3.0 billion" and confirm that the forecast balance of short term borrowings at March 31, 2012, 2013 and 2014 will be in excess of this amount. Please provide an explanation of how BC Hydro and the government of British Columbia will address this.

2.74.3 Please confirm that the numbers in the following table are correct.

FINANCIAL YEAR	$MM	2007	2008	2009	2010	2011	2012	2013	2014
SHORT TERM DEBT		836.5	995.9	1690.8	1923.6	2554.1	3017.8	3344.4	4273.1
DEFERRED CHARGES									
ENERGY		198.1	48.5	333.2	584.7	745.5	856.5	901.8	892.0
OTHER		251.4	523.9	682.6	1128.1	1554.2	1911.7	3253.2	3804.2
SUB-TOTAL		449.5	572.4	1015.8	1712.8	2299.7	2768.2	4155.0	4696.2
LESS NON-CASH									
FN SETTLEMENT		89.9	319.4	326.2	308.1	320.8	255.7	259.2	259.1
IFRS PENSION								723.0	688.3
ENVIRONMENTAL PROVISIONS					320.5	319.2	222.1	213.7	205.0
TOTAL NON-CASH		89.9	319.4	326.2	628.6	640.0	477.8	1195.9	1152.4
TOTAL CASH DEFERRED CHARGES		359.6	253.0	689.6	1084.2	1659.7	2290.4	2959.1	3543.8

(Source: Amended Appendix A, Tabs 8 and 2.2)

2.74.4 Please confirm that on a prima facie basis it would appear that BC Hydro's Deferred Charges have been and continue to be financed by the Province's Commercial Paper program.

TOPIC: REGULATORY ACCOUNTS

2.75.1 Please confirm that BC Hydro's weighted average cost of debt (WACD) and the short term interest rates forecast for the test period are as follows:

Percent	F2012	F2013	F2014
WACD	4.75	4.57	4.58
Short-term interest	0.97	1.26	2.20
Difference	3.78	3.31	2.38

(Source: Application, Amended Appendix A, Tab 8)

2.75.2 Please confirm that if BC Hydro were to calculate the interest it charges to its deferred accounts using its short term interest rate as opposed to its weighted average cost of debt, the result would, all other things being equal, be that the revenue requirement would increase and the amount carried forward in the deferral accounts would decrease.

2.75.3 Please confirm that the table below calculates how much has been carried forward to future years by BC Hydro funding its deferrals using Commercial Paper and charging interest on its deferral accounts using its weighted average cost of debt, (all numbers in $millions):

Interest Charged (S million)	**F2012**	**F2013**	**F2014**	**Total**
Energy	39.4	39.4	40.3	119.1
Other	15.0	28.3	41.2	84.5
Total	54.4	67.7	81.5	203.6
Short-Term				68.9
Rates	11.1	18.7	39.1	
Difference	43.3	49.0	42.4	134.7

(Source: Application, Amended Appendix A, Tab 2.2, and COPE378 calculation)

TOPIC: REGULATORY ACCOUNTS NOT AMORTIZED

2.76 As part of the plan to achieve rate increases of 8 per cent in F2012 and 3.91 per cent in F2013 and F2014, BC Hydro is proposing that it not consider amortization of the following regulatory accounts during the test period:

- First Nations settlement payments;
- Home Purchase Option; and
- Outsourcing Implementation Costs.

QUESTION:

2.76.1 Absent BC Hydro's commitment to minimize rate increases, and all else being equal, how would BC Hydro have addressed the issue of amortization for each of the three accounts listed above for F2014?

TOPIC: AUDITOR GENERAL'S REPORT

2.77 In his 2011/2012 Report 8, entitled "BC *Hydro: The Effects of Rate-Regulated Accounting",* the Auditor General states that; in his view "[G]overnment has three options for recovering deferred costs that need to be considered individually or in combination.

1 – Rate Adjustments

Government's report notes that BC Hydro has "not made any allowance with respect to the ability of BC Hydro to recover the regulatory assets through future rates." Government's policy has been to keep rates low. To avoid undue intergenerational inequity, rates could be adjusted, ensuring repayment over periods related to the benefit received by most customers.

2 – Operating Efficiencies

Government's recent report noted a number of opportunities to increase operational efficiency in the short and long term. We did not review evidence supporting any of government's specific suggestions; however, should these cost savings materialize, increased net revenues could be applied to deferral account balances.

3 – Infusion of Cash

Since the first deferral account was established in 2000, $3.2 billion has been withdrawn from BC Hydro in the form of dividends paid to the Province. Private sector companies usually pay dividends based on a history of positive financial results. As shown in this report, when the impact of rate-regulated deferrals is taken into account, BC Hydro's net equity – the funds available to invest – has been depleted over the last decade, in part by the dividends paid to the Province.

QUESTIONS:

2.77.1 Can BC Hydro identify any other options to reduce the amount in its deferral accounts?

2.77.2 Does BC Hydro agree that the Commission should instruct it to apply the closing F2011 credit balances in the Total Taxes Regulatory Account, the Amortization on Capital Additions Regulatory Account and the Total Finance Charges Regulatory Account ($27 million) against the accumulated balance in the NHDA rather than permit BC Hydro to apply the credit as a one-time reduction of the revenue requirement in the test period to comply with its "agreement" with government? If not, please fully explain why not.

2.77.3 What is the status of BC Hydro's plan to reduce the amounts deferred?

2.77.4 Does BC Hydro agree that such a plan should require the approval of the Commission?

TOPIC: SMI

2.78 BC Hydro states that all else being equal it will commence amortization of its smart meters in F2015 along with all the costs it proposes to defer in the SMI regulatory Account.

QUESTION:

2.78.1 Assuming that all SMI costs are recovered through the residential basic charge, please calculate the impact in F2015 on the basic charge of i) the meters and related infrastructure and ii) the amortization of the deferral account.

SMI Deferral and Capitalization of "soft costs"

2.79.1 Please confirm that the dollar value of O&M costs that BC Hydro proposes to capitalize and/or defer in the test period is as follows:

Year($MM)	F2012	F2013	F2014	Total
"Deferred OMA"	25.6	36.6	10.1	72.3
"Deferred Operating Costs"	46.4	50.4	15.2	112.0
Total	72.0	87.0	25.3	184.3

(Source: BCUC 1.292.2.2 and Amended Table 7-4)

2.80 In its Application dated March 31, 2010 for approval to create a regulatory account for SMI costs in the amount of $8.8 million, BC Hydro "advised that the expenditures in F2010 relate to planning, investigating and testing activities in relation to smart meters, theft detection and the related equipment and infrastructure; selection of smart metering technologies and vendors; finalization of business cases and deployment planning; and BC Hydro advised that it considers the expenditures as necessary to meet the requirements of section 64.04 of the Act, as amended".

QUESTION:

2.80.1 Please assist the reader in understanding what the $184.3 million will be spent on in the test period. Please provide an analysis of the expenditures by function and by cost type. Please provide details of the labour component, differentiating between FTEs, part time employees and contract staff and state what will happen to each labour component after the project's completion.

SMI Amortization of existing meters

2.81.1 Please identify the amortization included in the test period in respect of the existing meters that is included in the total revenue requirement that BC Hydro's customers are being asked to pay in the test period. Also indicate if these amounts are what the customers would have paid had there been no SMI initiative in this time period.

SMI Deferral of Return, Financing Costs and Interest

2.82 BC Hydro proposes to defer the following costs in the test period:

Year	F2012	F2013	F2014	Total
Additions - Finance Charges	9.1	22.8	29.2	61.1
Additions - ROE	7.1	17.1	22.2	46.4
Interest	4.3	10.4	16.8	31.5
Total	20.5	50.3	68.2	139.0

(Source: Application, Amended Appendix A, Tab 2.2)

QUESTIONS:

2.82.1 In its response to BCUC 1.312.3.1 BC Hydro states that "[T]he SMI meters that will go into service in the test years will be included in rate base and therefore will earn a return. However, BC Hydro is proposing to defer the ROE impact as shown on Schedule 2.2, line 96".

2.82.2 Please explain why it is that although BC Hydro is presenting an application for a 3-year test period on the basis that its customers would not be exposed to the cost impact of SMI, and would continue to charge its customers as though they still had the old meters, BC Hydro wants to book its full profit on these meters as though they were installed and providing service.

2.82.3 In its response to BCUC 1.292.3 BC Hydro calculates Finance Charges using a cost of debt for the three years of 5.03%, 5.13%, and 5.17%. Please provide the derivation of these percentages.

2.82.4 In its response to BCUC 1.292.4, BC Hydro states that "The interest of $31.6 million is the interest calculated on the outstanding balance in the SMI Regulatory Account over the test period".

2.82.5 Please comment on the observation that the ROE deferred in the SMI Regulatory Account is a book-keeping entry only and does not involve the outlay of cash. Please confirm that BC Hydro is charging interest on, *inter alia,* the ROE. If so confirmed, please justify.

TOPIC: DSM AMORTIZATION

2.83.1 Please confirm that because BC Hydro earns a return on its "rate base" which includes unamortized DSM, BC Hydro's revenues and earnings (and presumably the rates paid by customers) will increase as a result of extending the amortization to 15 years.

2.84.1 Please calculate the extra amount(in nominal dollars) BC Hydro's rate payers will have to pay as a result of extending the amortization to 15 years, as follows:

i. on the unamortized balance as at April 1 2011;

ii. on the DSM expenditures in the test period; and

iii. on each $1 million deferred thereafter.

2.85.1 Please comment on the suggestion that the Commission should only permit a change in the amortization period on a prospective basis and should require BC Hydro to continue to use the 10-year period the Commission endorsed up to the time BC Hydro had made its case to extend the period.

TOPIC: DSM ACCOUNTING POLICIES

2.86.1 Please confirm that BC Hydro is proposing to defer and amortize over the following 15 years the following amounts of indirect, administrative, and program support activities in the test period:

Year ($million)	F2012	F2013	F2014	Total
Rate Structures	5.5	4.7	6.5	16.7
Residential SEA	1.4	1.5	1.7	4.6
Commercial SEA	1.9	2.0	2.0	5.9
Industrial SEA	1.5	1.6	1.7	4.8
Public Awareness	7.8	8.0	8.5	24.3
Community Engagement	6.6	8.0	7.8	23.4
Technology Innovation	1.9	2.0	2.0	5.9
Codes and Standards	2.5	2.4	2.4	7.3
Information Technology	1.6	0.8	0.8	3.2
Indirect and Portfolio Enabling	10.6	9.9	10.9	31.4
Total	41.4	40.8	44.3	126.5

SEA = Sector Enabling Activities

(Numbers may not add due to rounding)

(Source: Application, Amended Appendix II Attachment 5)

2.87 BCUC 1.139.1 asks BC Hydro to explain the provisions of the regulatory order under which DSM expenditures have been deferred, including references to accounting rules/treatment and regulatory rules/treatment.

BC Hydro replied that it defers certain DSM costs based on Canadian Generally Accepted Accounting Principles (CGAAP), and the provisions of BCUC Order No. G-55-95, which provides direction on the accounting for expenditures and amortization of DSM costs, and states the following:

Costs incurred at different stages of program commercialization reflect varying degrees of uncertainty as to beneficial outcomes and shall be deferred according to the following criteria:

(b) Direct program costs, indirect administration costs and allocated overhead, shall be deferred according to the intent of section 3450 - Research and Development, of the Canadian Institute of Chartered Accountants, Accounting Recommendations Handbook. Generally speaking, those criteria treat research costs as expenses and treat as assets, those development costs that have a high probability of achieving net financial benefits.

BC Hydro also notes that Section 3450 – Research and Development, of the Canadian Institute of Chartered Accountants (CICA) Accounting Recommendations Handbook, was replaced by Section 3064 – Goodwill and Intangibles, in 2008.

QUESTIONS:

2.87.1 Please provide a copy of Order G-55-95 as well as a copy of CICA Handbook section 3064.

2.87.2 Please discuss whether the CICA envisaged a scenario whereby on- going program support costs could continue to be deferred for 15-20 years and still comply with CGAAP.

2.87.3 Please also comment on the observation that, in order to comply with what was CGAAP in 1995, BC Hydro would have to have maintained development costs of each of its programs, requiring the use of time sheets, expense claims and third party invoices on a program-by-program basis. Is it possible that BC Hydro has followed such practices?

2.88.1 BC Hydro's website offers a section entitled "Team Power Smart" which talks about contests, prizes, excellence awards, perquisites, discounts, an annual Forum, celebrities and such like. Into which account does BC Hydro charge these activities? Are they deferred and amortized over 15 years?

2.89 In response to BCUC 1.458.3 BC Hydro states that:

"The residential Behaviour Program is based on the premise that customers will change their energy consuming behaviours through increased engagement, learning which behaviour changes will result in energy savings and having these actions reinforced and rewarded until they become habit.

BC Hydro assumes that changes in energy saving behaviours of nearly half of program participants will not continue through the first year. Of the remaining participants, savings are assumed to continue for 30 years. However, savings are reduced by 20 per cent after two years to account for some relapse in the energy saving behaviours of participants. In this way, BC Hydro has forecast the energy savings according to its estimate of when they would occur over the 30-year period".

QUESTIONS:

2.89.1 Please confirm that, all else being equal, BC Hydro is proposing to amortize the full amount of each year's expenditure on its residential behaviour program over the following 15 years.

2.89.2 Please comment on the proposition that it would be more realistic to expense half the expenditure in year 2 and the balance over the remaining 30 years on a form of "unit of production" method of amortization?

TOPIC: COLUMBIA RIVER TREATY

2.90.1 Please confirm that the amounts in column 6 of the Table below are reasonable proxies for amounts received by the Province from Powerex for the CE under the terms of the EAA, or if they are not confirmed, please correct them:

1 Fiscal Year	2 CE Energy(GWh)	3 Mid-C Price ($US)	4 Total USD (SMM)	5 Conversion	6 Total CAD (SMM)
2005	4,707	46.35	218	1.21	264
2006	4,694	63.35	297	1.13	336
2007	4,416	50.08	221	1.07	236
2008	4,258	62.75	267	1.06	283
2009	4,125	55.88	230	1.14	262
2010	4,669	37.52	175	1.03	180
2011	4,785	31.49	151	0.99	150
2012	4,648	32.73	152	1.00	152
2013	4,482	40.88	183	1.00	183
2014	4,425	46.20	204	1.00	204

(Source: COPE 1.4.1)

2.90.2 How much capacity did BC Hydro request Powerex to reserve in these years? How much energy did BC Hydro take under these reservations? How much did BC Hydro pay for it?

2.90.3 When did BC Hydro receive the Columbia River Treaty contributions, from whom and in respect of what?

2.90.4 Do the assets on BC Hydro's books (the Mica, Duncan and Arrow dams) provide the infrastructure that enables the province to receive the Downstream Benefits?

2.90.5 Please confirm that BC Hydro's ratepayers pay the PTP charges but that the province garners all the benefits of the CE. Can the Commission do anything to rectify this apparent anomaly?

TOPIC: CHANGE IN "SELF-SUFFICIENCY" DEFINITION AND INCREMENTAL SUPPLY FROM IPPS

2.91.1 What changes has BC Hydro implemented with respect to entering into additional energy supply agreements with independent power producers in consequence of the change to the legal definition of "self-sufficiency" under the Clean Energy Act?

In particular,

a. Is BC Hydro continuing to process proposed IPP projects which have not reached the stage of binding legal commitments? If so, why?

b. Does BC Hydro intend to continue entering into contractual obligations with IPPs for the supply of incremental power? If so, why?

c. Are there any executed EPAs which are in default, or which BC Hydro believes it could legally rescind or terminate for any other reason? If so why has BC Hydro not done so?

TOPIC: KITIMAT-AREA LIQUEFIED NATURAL GAS PROJECTS

2.92 reference: Exhibit B-1-3A, Amended Appendix C, Cover Letter at page 3:

> In addition, the B.C. Government has indicated a high potential for the electrification of LNG export facilities from clean resources in BC. Two potential LNG projects, KM LNG and Douglas Channel LNG, have obtained material government agency permits and approvals such as National Energy Board export permits. Of these two LNG projects, KM LNG is by far the larger. As a result, the LRBs for energy and capacity are presented for the reference 2011 Load Forecast with and without KM LNG.

This passage is footnoted as follows: "The KM LNG facility is expected to consume approximately 5,300 GWh/year and 680 MW including losses."

QUESTIONS:

2.92.1 Please confirm that there is a third LNG project proposed for the Kitimat area, which would be developed by Shell, which has not yet obtained the necessary government agency permits, but which has also been the subject of B.C. Government comment in addition to the two projects referenced above as a potential candidate for electrification of the liquefaction process. If this is not confirmed please specify to what extent and why.

2.92.2 What is BC Hydro's understanding of the energy and capacity requirement of each of the other two LNG projects?

2.92.3. According to your best information, when would each of the loads (or incremental phases of the loads) come into service?

2.92.4 With respect to each of the three projects, please indicate:

a. the long term incremental cost of providing the requisite energy on an annual basis, and

b. the annual revenue which BC Hydro would receive from the operator based on the current tariff.

2.92.5 Please estimate the total percentage rate impact on BC Hydro ratepayers if the three LNG projects all proceeded as expected and were billed under the current tariff.

2.92.6 Is it BC Hydro's understanding that the three LNG projects could perform the liquefaction process using an intermittent supply of electricity?

2.92.7 Please describe BC Hydro's current thinking about how to meet the energy requirement in order to service the loads represented by the three LNG plants (taken as a whole, or individually if the thinking differs on that basis) including the type(s) of generation resources potentially available for that purpose.

2.92.8 Please describe BC Hydro's current thinking about the transmission requirements in order to service the loads, how those requirements might be met, and your best estimate of the likely capital cost of doing so.

2.92.9 Please confirm that the usual fuel for liquefaction of natural gas for loading onto ships for export, globally, is natural gas rather than electricity.

2.92.10 Please discuss the potential for an entity other than BC Hydro being the provider of the electricity required by the three LNG projects, and the potential for such a strategy to prevent a cross-subsidy of the projects by other ratepayers.