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December 17, 2007

Ms. Joanna Sofield
Chief Regulatory Officer
British Columbia Hydro and Power Authority
17th Floor, 333 Dunsmuir Street
Vancouver, B.C. V6B 5R3

Dear Ms. Sofield:

British Columbia Hydro and Power Authority ("BC Hydro")
BC Hydro 2007 Rate Design Application – Phase 1
October 26, 2007 Decision

ERRATUM

Page 201 Section 6.2 Miscellaneous Rate Schedules Second Paragraph:

> "Rate Schedules 1277 and 1279" should read "Rate Schedules 1277 and 1278".

Page 210 Directive No. 28

> "Rate Schedules 1277 and 1279" should read "Rate Schedule 1277 and 1278".

Yours truly,

Original signed by

Erica M. Hamilton

EC/rt

IN THE MATTER OF

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

2007 RATE DESIGN APPLICATION
PHASE -1

DECISION

October 26, 2007

Before:

Anthony J. Pullman, Panel Chair & Commissioner
Robert J. Milbourne, Commissioner
L.A. O'Hara, Commissioner

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1.0 REGULATORY AND POLICY FRAMEWORK

These Reasons for Decision regarding the Phase I of the 2007 Rate Design Application ("2007 RDA") are set out as follows:

Section 1 describes the regulatory and policy framework in which the British Columbia Utilities Commission ("the Commission" or "BCUC") and British Columbia Hydro and Power Authority ("BC Hydro") operate.

Section 2 describes BC Hydro, its rate design history, its 2007 RDA, the conduct of the Hearing, BC Hydro's consultation with its stakeholders, and BC Hydro rate design principles and regulatory timetable.

Section 3 describes BC Hydro's Fully Allocated Cost of Service Study ("FACOS") and Sections 4 and 5 review BC Hydro's proposals for its Rate Schedules and the Terms and Conditions for service respectively in its Electric Tariff.

Section 6 describes miscellaneous matters that arose in the proceeding.

1.1 Relevant Legislation

The Commission is a regulatory agency of the Provincial Government operating under, and administering, the Utilities Commission Act ("UCA", the "Act"). The Commission's primary responsibility is the regulation of public utilities under its jurisdiction to ensure that the rates charged for service are fair, just and reasonable, that utility operations are safe, that adequate and secure service is provided to customers, and that the opportunity for utilities to earn a fair and adequate financial return is preserved. It also approves construction of new facilities planned by utilities. The Commission's function is quasi-judicial, and its decisions and orders may be appealed to the Court of Appeal on questions of law or excess of jurisdiction with leave of a justice from the Court of Appeal.

BC Hydro is a provincial Crown Corporation, wholly owned by the Province of British Columbia. It was created by Act of the Provincial Legislature on March 30, 1962 as the successor, by amalgamation, of the British Columbia Electric Company Limited ("BCEC") and the British Columbia Power Commission ("BCPC") which had been the two major suppliers of electricity in the province prior to that time. BCEC supplied power to the populous south western part of the province and had been an investor-owned utility prior to its take-over by the Provincial Government in 1961. The BCPC was a Provincial Crown Corporation organized in 1945 to improve the availability and supply of electric power in many of the less densely populated areas of the province.

Under provisions of the UCA, which was proclaimed September 11, 1980, BC Hydro became subject to general regulatory jurisdiction for the first time. Rates in effect at September 11, 1980 were validated by the then section 141(4) of the UCA which deemed them to have been filed with the Commission and to be lawful, enforceable and collectible rates of BC Hydro at that date.

The Commission receives guidance from provisions of the UCA, inclusive of Special Directions issued by order of the Lieutenant Governor in Council pursuant to Section 3 of the UCA. The following sections of the UCA are particularly applicable to the 2007 RDA.

1.1.1 Utilities Commission Act

Commission may order amendment of schedules

58 (1) The commission may,

(a) on its own motion, or

(b) on complaint by a public utility or other interested person that the existing rates in effect and collected or any rates charged or attempted to be charged for service by a public utility are unjust, unreasonable, insufficient, unduly discriminatory or in contravention of this Act, the regulations or any other law,

after a hearing, determine the just, reasonable and sufficient rates to be observed and in force.

(2) If the commission makes a determination under subsection (1), it must, by order, set the rates.

(3) The public utility affected by an order under this section must

(a) amend its schedules in conformity with the order, and

(b) file amended schedules with the commission.

Discrimination in rates

59 (1) A public utility must not make, demand or receive

(a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia, or

(b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

(2) A public utility must not

(a) as to rate or service, subject any person or locality, or a particular description of traffic, to an undue prejudice or disadvantage, or

(b) extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description.

(3) The commission may, by regulation, declare the circumstances and conditions that are substantially similar for the purpose of subsection (2) (b).

(4) It is a question of fact, of which the commission is the sole judge,

(a) whether a rate is unjust or unreasonable,

(b) whether, in any case, there is undue discrimination, preference, prejudice or disadvantage in respect of a rate or service, or

(c) whether a service is offered or provided under substantially similar circumstances and conditions.

(5) In this section, a rate is "unjust" or "unreasonable" if the rate is

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,

(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or

(c) unjust and unreasonable for any other reason.

Setting of rates

60 (1) In setting a rate under this Act or the regulations

(a) the commission must consider all matters that it considers proper and relevant affecting the rate,

(b) the commission must have due regard to the setting of a rate that

(i) is not unjust or unreasonable within the meaning of section 59,

(ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands, and

(iii) encourages public utilities to increase efficiency, reduce costs and enhance performance, (b.1) the commission may use any mechanism, formula or other method of setting the rate that it considers advisable, and may order that the rate derived from such a mechanism, formula or other method is to remain in effect for a specified period, and

(c) if the public utility provides more than one class of service, the commission must

(i) segregate the various kinds of service into distinct classes of service,

(ii) in setting a rate to be charged for the particular service provided, consider each distinct class of service as a self contained unit, and

(iii) set a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates fixed for any other unit.

(2) In setting a rate under this Act or regulations, the commission may take into account a distinct or special area served by a public utility with a view to ensuring, so far as the commission considers it advisable, that the rate applicable in each area is adequate to yield a fair and reasonable return on the appraised value of the plant or system of the public utility used, or prudently and reasonably acquired, for the purpose of providing the service in that special area.

(3) If the commission takes a special area into account under subsection (2), it must have regard to the special considerations applicable to an area that is sparsely settled or has other distinctive characteristics.

(4) For this section, the commission must exclude from the appraised value of the property of the public utility any franchise, licence, permit or concession obtained or held by the utility from a municipal or other public authority beyond the money, if any, paid to the municipality or public authority as consideration for that franchise, licence, permit or concession, together with necessary and reasonable expenses in procuring the franchise, licence, permit or concession.

Rate schedules to be filed with commission

61 (1) A public utility must file with the commission, under rules the commission specifies and within the time and in the form required by the commission, schedules showing all rates established by it and collected, charged or enforced or to be collected or enforced.

(2) A schedule filed under subsection (1) must not be amended without the commission's consent.

(3) The rates in schedules as filed and as amended in accordance with this Act and the regulations are the only lawful, enforceable and collectable rates of the public utility filing them, and no other rate may be collected, charged or enforced.

(4) A public utility may file with the commission a new schedule of rates that the utility considers to be made necessary by a rise in the price, over which the utility has no effective control, required to be paid by the public utility for its gas supplies, other energy supplied to it, or expenses and taxes, and the new schedule may be put into effect by the public utility on receiving the approval of the commission.

(5) Within 60 days after the date it approves a new schedule under subsection (4), the commission may,

(a) on complaint of a person whose interests are affected, or

(b) on its own motion,

direct an inquiry into the new schedule of rates having regard to the fixing of a rate that is not unjust or unreasonable.

(6) After an inquiry under subsection (5), the commission may

(a) rescind or vary the increase and order a refund or customer credit by the utility of all or part of the money received by way of increase, or

(b) confirm the increase or part of it.

To summarize the different wordings between the Act and Special Directions, and for ease of reference, BC Hydro refers in its submissions to the legal test that its proposed rates, and the rates the Commission must determine and set, are "fair, just and not unduly discriminatory" (BC Hydro Argument, p. 15).

1.1.2 Special Directions

Under section 3 of the UCA, the Commission must comply with any general or special direction, made by regulation of the Lieutenant Governor in Council, with respect to the exercise of its powers and functions. For the 2007 RDA, the relevant Special Directions from a historic and current perspective are as follows:

The 1991 Special Direction No. 3 ("SD3") to the Commission required BC Hydro rates to

- *contribute to conservation and the efficient use of electricity;*
- *recognize the higher cost of new electricity supply;* (emphasis added)
- provide smooth and stable increases; and
- be otherwise fair, just and reasonable (Exhibit B-3, ESVI 1.14.0, Attachment 4, April 24, 1992 Decision, p. 13).

SD3 was revoked by Special Direction No. 8 ("SD8"), dated November 13, 1992, which directed the Commission, in the exercise of its powers and functions, to "*ensure that those rates contribute to conservation and efficient electricity use by reflecting the total cost of new sources of electric supply*, and those costs shall be evaluated using a cost of capital consistent with that earned on a pre-income tax basis by the most comparable investor-owned energy utility regulated under the Act" (emphasis added).

SD8 was repealed and replaced by Special Direction No. 9 (“SD9”), which became effective April 1, 2004 as did the Heritage Special Direction No. HC2 (“HC2”). SD9 establishes capital structure and allowed return on equity for British Columbia Transmission Corporation (“BCTC”). It also establishes deferral accounts and gives the Commission direction regarding approvals of new transmission system capital investment.

HC2 was a result of the Commission Report and Recommendations on the “Inquiry Into a Heritage Contract for BC Hydro’s Existing Generation Resources and Regarding Stepped Rates and Transmission Access” dated October 17, 2003. It gives the Commission direction in number of areas, including considerations in designing rates for transmission rate customers, the basis for establishing BC Hydro’s revenue requirements, and determining the cost of Heritage Energy and return on equity.

On June 25, 2007, pursuant to section 3 of the UCA Special Direction No. 10 (“SD10”) to the Commission was made by Order in Council (“OIC”) No. 508. It includes definitions of “integrated area” and “non-integrated area” (“NIA”). It requires the Commission to use the criterion that BC Hydro is to achieve energy and capacity self sufficiency by 2016, and exceed the electricity supply obligations by at least 3,000 gigawatt hours “as soon as practicable but no later that 2026”. It also addresses biomass contracts. Paragraph 5(1) of SD10 provides that:

> “In setting rates for the authority, the commission must ensure that the authority’s rates and classes of service available to customers in the non-integrated area, including rates available to customers whose electricity demand is or is likely to be in excess of 45 kV.A, are available to customers who receive electricity service under section 2 of the Remote Communities Regulation.”

Pursuant to section 4 the BC Hydro Public Power Legacy and Heritage Contract Act, S.B.C 2003, the Remote Communities Regulation was made by OIC 509 also on June 25, 2007. It is designed to provide eligible and willing remote communities, identified on the attached schedule, access to BC Hydro electricity service under BC Hydro’s Zone II tariff.

On February 27, 2007 the Provincial Government released the 2007 Energy Plan, as discussed at Section 1.4 below. To date, the only new legislation in place regarding the 2007 Energy Plan is SD10 and the Remote Communities Regulation.

1.2 2002 Energy Plan

The Provincial Government's "Energy for Our Future: A Plan for BC" ("2002 Energy Plan"), issued on November 25, 2002, contains four cornerstones, as well as 26 Policy Actions designed to accomplish the objectives of the 2002 Energy Plan. Since that Plan was the first comprehensive statement of government energy policy, it provides significant context for the Commission's review of BC Hydro's rates and rate design proposals.

The four cornerstones of the 2002 Energy Plan are:

- low electricity rates and public ownership of BC Hydro;

  "Low-cost electricity will be an enduring economic advantage during the next decade. Legislation will entrench the benefits of our publicly owned hydroelectric power assets, and will ensure efficient regulation to keep rates low, maintain industry competitiveness, and support economic growth."

- secure, reliable supply;
- more private sector opportunities; and
- environmental responsibility and no nuclear power sources. (Order No. G-29-07, Decision, p.12)

The Policy Actions include:

- Policy Action #1: A legislated heritage contract will preserve the benefit of BC Hydro's existing generation.
- Policy Action #2: BC Hydro ratepayers will continue to benefit from electricity trade.
- Policy Action #5: The BCUC will once again regulate BC Hydro rates.
- Policy Action #14: Under new rate structures, large electricity consumers will be able to choose a supplier other than the local distributor.

- Policy Action #20: Electricity distributors will pursue a voluntary goal to acquire 50 percent of new supply from BC Clean Electricity over the next 10 years.
- *Policy Action #21: New rate structures will provide better signals to large electricity consumers for conservation and energy efficiency* (emphasis added).

1.3 Heritage Contract

The 2002 Energy Plan recognizes that BC Hydro's Heritage Resources represent a valuable provincial asset. The enabling legislation, the *BC Hydro Public Power Legacy and Heritage Contract Act* allowed Government to require BC Hydro Distribution and BC Hydro Generation to sign a "Heritage Contract" to ensure the electricity generated by the Heritage Resources continues to be available to BC Hydro ratepayers based on cost of service, not market prices.

The Government further described its Policy Action #1 in the 2002 Energy Plan as follows:

> "The Heritage Contract will essentially lock in the value of existing low-cost generation assets for an extended period. It will be implemented through legislation that specifies the term and amount of energy involved. The contract's term will initially be ten years, with provisions for renewal thereafter, and the quantity of energy will be the production from BC Hydro's system under average water conditions. The BC Utilities Commission will review and recommend the terms and conditions for the energy based on a return consistent with private utilities."
>
> (2006 IEP/LTAP Proceeding, (Exhibit B-1B, Appendix A)

The Heritage Contract, which was attached as Appendix A to HC2, is reproduced for the record as follows:

APPENDIX A TO HERITAGE SPECIAL DIRECTION NO. HC2

HERITAGE CONTRACT

WHEREAS on November 25, 2002, the Province of British Columbia released Energy for Our Future, A Plan for B.C. (the "Energy Plan");

AND WHEREAS the Energy Plan outlines certain policy actions designed to ensure British Columbians have continued access to sufficient supplies of dependable low-cost electricity;

AND WHEREAS the Energy Plan provides in Policy Action #1 that a legislated heritage contract will be created between BC Hydro's generation line-of-business and BC Hydro's distribution line-of-business for an initial term of 10 years.

THEREFORE, BCH Distribution and BCH Generation (the "parties") agree as follows.

Definitions

1. In this Agreement:

"Act" means the *BC Hydro Public Power Legacy and Heritage Contract Act*;

"Agreement" means this Heritage Contract including Schedule A;

"Ancillary Service Requirements" means services necessary to deliver energy;

"BC Hydro" means the British Columbia Hydro and Power Authority;

"BCH Distribution" means BC Hydro's distribution line-of-business;

"BCH Generation" means BC Hydro's generation line-of-business;

"Commission" means the British Columbia Utilities Commission;

"heritage electricity" means the capacity, energy and ancillary services that BCH Generation is required to supply to BCH Distribution under this Agreement;

"heritage energy" means

(a) subject to paragraph (b), 49 000 GW.h per year less the energy generated for delivery under the Skagit Valley Treaty, or

(b) the quantity of energy determined by the Commission under section 8 of this Agreement to be heritage energy;

"heritage payment obligation" means

(a) subject to paragraph (b), the annual payment determined in accordance with the procedure set out in Schedule A to this Agreement, or

(b) the annual payment determined by the Commission under section 8 of this Agreement to be the heritage payment obligation;

"heritage resources" means the Electric Facilities and Thermal Facilities described in Schedule A to the Terms of Reference, together with

(a) the related civil works and plant, and

(b) potential future investments that increase the capacity, energy or ancillary service capability of such facilities, including potential future units 5 and 6 at Mica and potential future units 5 and 6 at Revelstoke;

"Order" means an order of the Commission;

"Terms of Reference" means Schedule A, Terms of Reference, to Order-in-Council No. 0253/2003;

"Transfer Pricing Agreement" means the Transfer Pricing Agreement for Electricity and Gas dated April 1, 2003 between BC Hydro and Powerex Corp. as amended from time to time;

"Year" means fiscal year.

Electricity Supply

2. BCH Generation must provide the full capacity of the heritage resources to BCH Distribution on a priority call basis.

Obligation to supply

3. BCH Generation must supply to BCH Distribution, in each Year, the heritage energy or such lesser amount of energy as may be required by BCH Distribution.

Obligation to deliver

4. BCH Generation will deliver the heritage energy to BCH Distribution at the various points of interconnection of the generating stations included in the heritage resources with the BC Hydro transmission grid or at points of interconnection with other utilities, as appropriate.

Responsibility for obtaining transmission services

5. BCH Distribution will be responsible for obtaining transmission services for energy provided to BCH Distribution.

Ancillary services

6. The parties may use the capacity available to them under section 2 to deliver energy to meet customer demand and to satisfy the parties' Ancillary Service Requirements, regardless of whether provision for self-supply is made under any tariff.

Payment

7. BCH Distribution must, on or before the end of each Year, pay to BCH Generation an amount equal to the heritage payment obligation.

Adjustment

8. The parties acknowledge that

   (a) the Commission may, by Order, modify one or both of the definitions of "heritage energy" and "heritage payment obligation" if the commission is satisfied that a change in circumstances has permanently affected

      (i) the capability of the heritage resources to provide one or both of capacity and energy, or

      (ii) the authority's cost of generating the heritage energy, and

   (b) any such modification will automatically modify the heritage energy or the heritage payment obligation, as the case may be, without further action by the parties.

Information exchange and cooperation

9. Each party will continue to freely provide the other with any requested information to facilitate the coordinated and optimal operation of the BC Hydro system.

Dispute resolution

10. (1) The parties will make reasonable efforts to resolve disputes arising in relation to this Agreement at the staff level.

(2) As needed, issues may be dealt with by management levels within each party to achieve timely resolution.

(3) Issues that cannot be resolved in a timely manner at senior management levels, may be referred by either party to the commission for resolution.

Term and termination

11. (1) This Agreement shall commence on April 1, 2004.

(2) This Agreement may be terminated by government, with 5 years notice, any time after April 1, 2009 and if such notice is given, the Agreement shall terminate at the end of the 5-year notice period without any further action by the parties or the government.

Dated as of this ____ day of ________, 2004.

BCH Distribution

BCH Generation

SCHEDULE A

HERITAGE PAYMENT OBLIGATION

The heritage payment obligation for any Year is the amount determined by

(a) adding those of the following costs incurred by BCH Generation in the Year that the Commission orders may be included in the heritage payment obligation:

(i) cost of energy such as the cost of water rentals and energy purchases, including purchases of gas and electricity, required to supply heritage electricity;

(ii) operating costs such as the costs of operating and maintaining the heritage resources, including an allocation of corporate costs;

(iii) all costs of owning the heritage resources, including, without limitation, depreciation, interest, finance charges and other asset related expenses;

(iv) all costs or payments related to generation-related transmission access required by the heritage resources;

(v) the applicable return on equity on investments in heritage resources based on Heritage Special Direction No. HC2 to the Commission under the authority of the Act, and

(b) by subtracting from the sum obtained under paragraph (a), any revenues BCH Generation receives from other services provided from the heritage resources, including, without limitation,

(i) revenues related to Skagit Valley Treaty obligations,

(ii) revenues from provision of ancillary services to the transmission operator in respect of third party use of the transmission system, and

(iii) revenues from the sale of surplus hydro electricity under section 5 of the Transfer Pricing Agreement.

The goal is to ensure British Columbians have continued access to supplies of dependable low-cost electricity. The Heritage Contract was implemented by way of the Heritage Contract HC2 addressed in Section 1.1.2.

The first and most important element of the Heritage Contract of direct relevance to the current RDA is that BC Hydro's rates are established on a cost of service basis. This means that the Utility's customers get the full benefit of the Heritage Resources, subject to the $ 200 million cap on Trade Income. BC Hydro submits that another important corollary element is the principle that new customers should be able to benefit from low-cost Heritage Resources, as shown on Schedule B to the Terms of Reference attached to the Heritage Contract Report as Attachment A (Exhibit B-3, Heiltsuk 1.7.1).

BC Hydro also submits that the Commission was left with significant discretion, pursuant to HC2, to design rates for all BC Hydro customers that balance the competitive interests of different customer classes and allocate the benefit of the Heritage Resources among customer classes. Accordingly, BC Hydro concludes that the Commission's over-arching jurisdiction under the UCA to determine rates that are just and reasonable was left intact (Exhibit B-3, Heiltsuk 1.7.1).

1.4 2007 Energy Plan

Further setting the context within which the Commission must address the 2007 RDA is a document released by the Provincial Government on February 27, 2007 entitled "The BC Energy Plan: A Vision for Clean Energy Leadership" ("2007 Energy Plan"). This new Energy Plan sets out a large number of policy actions that place emphasis on *energy conservation, energy efficiency, clean energy and self sufficiency* (emphasis added). It also re-enforces and advances further the message and direction given to BC Hydro by the Government in its 2002 Energy Plan and builds on its goals. Relevant elements of the 2007 Energy Plan are addressed in more detail below.

1.4.1 Conservation Targets

Policy Action 1 sets an ambitious conservation target, to acquire 50 percent of BC Hydro's incremental resource needs through conservation by 2020. According to the 2007 Energy Plan this will require building on the "culture of conservation" that British Columbians have embraced in recent years (Exhibit B-3, ESVI 1.6.1, Attachment, p. 5). The Plan confirms action on the part of government to complement these conservation targets by working closely with BC Hydro and other utilities to research, develop and implement best practices in conservation and energy efficiency, and to increase public awareness. In addition, the Plan supports utilities in British Columbia and the BCUC pursuing all cost effective and competitive demand side management ("DSM") programs. *Utilities are also encouraged to explore and develop rate designs to encourage efficiency and conservation* (emphasis added). According to the 2007 Energy Plan, this may also involve clarifying the criteria the Commission uses in its oversight of utility rates and other utility efforts designed to promote conservation.

To put the conservation target in context, by 2020, 10,000 GW.h of currently forecast needs are to be met through demand reduction measures. This amount represents about 20 percent of the 52,000 GW.h of electricity BC Hydro required in 2006 to meet the needs of British Columbians (Exhibit B-7, BCUC 2.90.1, Attachment 1, p. 1). In April 2007, BC Hydro's CEO referred to the current average household electricity consumption of about 10,000 kWh per year, and stated that in order to achieve the conservation target, electricity use per household will need to drop to approximately 9,000 kWh per year by 2020, or 10 percent (Exhibit B-10, Panel 1.8.0).

1.4.2 Self Sufficiency

Policy Action 10 sets the direction to ensure self-sufficiency to meet electricity needs, including "insurance", in British Columbia by 2016. This policy is enshrined in legislation by SD10. In paragraph 3, SD10 directs the Commission to use the criterion that BC Hydro is to achieve energy and capacity self-sufficiency by becoming capable of meeting, by 2016 and each year thereafter, the electricity supply obligations, and exceeding, as soon as practicable but no later than 2026, the electricity supply obligations by at least 3,000 GW.h per year.

Through the 2007 Energy Plan, the Government will set policies to guide BC Hydro in producing and acquiring enough electricity in advance of future need. Specifically, the Government wants to ensure that BC Hydro has enough BC-based power at all times, even in low water years, to meet customer demand. Further, because electricity generation and transmission infrastructure require long lead times, BC Hydro is directed to acquire additional supply of "insurance power" beyond the projected increases in demand to minimize the risk and implications of having to rely on electricity imports. The Commission will continue to have responsibility for regulating BC Hydro, within the context of the self-sufficiency requirement (Exhibit B-3, ESVI 1.6.1, Attachment, p. 10; Exhibit B-7, BCUC 2.90.1, Attachment 1, p. 8).

1.4.3 Rate Design

With specific reference to utility rates, Policy Action 4 addresses the use of pricing structures as a DSM tool either to discourage consumption overall, or to shift demand to less costly periods. *Specifically, it encourages all utilities to explore, develop and propose to the Commission additional innovative rate designs that encourage efficiency, conservation and the development of clean or renewable energy* (emphasis added). These include stepped rates for other rate classes (after the 2006 introduction of stepped rates for industrial customers), interruptible/curtailable rates, critical period rates, clean electricity supply rates, tariffs focused on promoting energy efficient new construction and others. This work is to include consideration of the benefits of 'smart' or advanced metering technology, which offer potential for greater consumption information and control being available to the consumer.

The Ministry of Energy, Mines and Petroleum Resources will monitor and assess progress on the development and implementation of price structures and advanced metering to encourage energy efficiency and conservation, and may propose additional regulatory measures (e.g., Special Directions) if required (Exhibit B-7, BCUC 2.90.1, Attachment 1, p. 3).

1.4.4 "Zero Net" Greenhouse Gas Emissions

Policy Action 18 requires that all new natural gas or oil fired electricity generation projects will have zero net greenhouse gas emissions ("GHG"). This means that the proponents of these generation projects would have to invest in other initiatives that would completely offset the GHG emissions generated by these projects, unless the technology was available to eliminate or capture and sequester the emissions from the plant (Exhibit B-7, BCUC 2.90.1).

To ensure consistent treatment between new and existing generation projects, while allowing time for this change, the 2007 Energy Plan also commits, in Policy Action 19, that by 2016 all existing thermal generation power plants will completely offset their GHG emissions (Exhibit B-7, BCUC 2.90.1, Attachment 1, p. 12).

1.4.5 Promote Energy Efficiency and Alternative Energy

In its 2007 Energy Plan the Provincial Government also states:

> "It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is potential to promote energy efficiency and alternative energy supplemented by natural gas. Combinations of alternative energy sources with natural gas include solar thermal and geothermal. Working with municipalities, utilities and other stakeholders the provincial government will promote energy efficiency and alternative energy systems, such as solar thermal and geothermal throughout the province (Exhibit B-3, ESVI 1.6.1, Attachment 1, p. 21).

The subject of fuel choice is further addressed in Section 5.3.1.

1.4.6. Remote Communities

Policy Action 27 relates to the Government and BC Hydro's planned Remote Community Electrification Program ("RCE") to expand or take over electricity service to remote communities in B.C. There are approximately 50 permanent remote communities in B.C. that are self-reliant or reliant on a third party for electric power. For many of these communities, electricity service is characterized by sub-standard reliability and potentially significant environmental impact related to diesel emissions and fuel handling.

Over the next 10 years, BC Hydro is expected to pursue its RCE to expand its service to remote communities that meet specific criteria and are seeking service from BC Hydro. Service to these communities is to be provided based on the same rates and classes as available in the non-integrated areas. Costs will be recovered from currently-responsible agencies and BC Hydro ratepayers. Section 2 of the Remote Communities Regulation provides that:

> "To provide them with the benefits of the heritage resources, the authority must provide electricity service to persons
>
> (a) whose premises are located within 90 meters of a distribution system, and
>
> (b) who apply to the authority for service and pay or agree to pay the rates established for that service under the *Utilities Commission Act*" and the regulations made under that Act." (Exhibit B-21)

In addition, Policy Action 28 directs BC Hydro to consider alternative electricity sources and energy efficiency measures in its energy planning for remote communities (Exhibit B-7, BCUC 2.90.1, p. 16).

1.5 BC Hydro Positions

BC Hydro takes the position that its 2007 RDA sets the foundation for BC Hydro's future rate design proposals that will address the opportunities to use rate structures to contribute to the implementation of the Government's 2007 Energy Plan. A suitable foundation is, in BC Hydro's submission, one that is consistent with the 2007 Energy Plan and which will not materially impair the ability of BC Hydro to bring forward new rate and rate related applications in a timely way to address the 2007 Energy Plan (BC Hydro Argument, p.4). Further, BC Hydro submits that it is currently developing a long-term rate strategy that will be informed by the 2007 Energy Plan and that will set the course for future rate changes and new rates that are designed to promote energy conservation and load management (Exhibit B-1, p. 3).

As a panelist, participating in the Pacific Economic Summit on May 31, 2007, BC Hydro's CEO made a number of observations that are relevant in the context of the 2007 Energy Plan and the 2007 RDA (Exhibit C7-12). Some relevant excerpts are as follows:

<u>Future Vision of Electricity Consumption</u>

- We will consume only what we need.
- People will make their own decisions about how to consume, and where their energy comes from – as part of a community, as tenants in a building, as a part of a subdivision or as families living in a home.
- In the home, and in the office, we will have hand held devices that control our appliances, so we set our consumption precisely to meet the way we live.
- At times when the system is stressed, the utility will send signals that range from requests for voluntary saving to prearranged turndowns of appliances or of overall consumption.

<u>Action Plan</u>

- **At BC Hydro, we will move quickly to implement rate structures that give real price signals at the margin to our customers** [emphasis added].
- In BC the combination of a smart distribution grid, with smart meters, will be fully implemented before 2012.
- The new future will take 15 or more years to build. BC Hydro has been planning for that future for over the last three years.
- Our job at BC Hydro is to articulate a clear vision; **to lead in the area of encouraging energy efficiency and conservation; to provide the right rate structure and incentives and partnerships to create conditions where great ideas will flourish**; to invest successfully in our backbone of large hydro facilities, as well as in a new smart grid, smart meter future; to support the strengthening of the transmission network within BC and with our neighbours; and to buy efficiently from renewable power producers in a way that takes the full measure of the best available technologies in a competitive environment [emphasis added].

2.0 BACKGROUND AND THE APPLICATION

2.1 The Applicant

BC Hydro is one of the largest electric utilities in Canada, serving more than 1.7 million residential, commercial and industrial customers in an area representing some 94 percent of British Columbia's population. Its integrated electric system includes Heritage hydroelectric generation which supplies some 10,000 MW of generating capacity and approximately 47,000 GWh of energy per year; two gas-fired thermal power plants; and a number of independent power producer ("IPP") projects with whom BC Hydro has contracts. The existing and committed supplies constitute some 11,000 MW of dependable capacity and approximately 57,000 GWh of energy per year.

BC Hydro delivers electricity over 72,000 kilometres of transmission and distribution lines. The transmission lines while owned by BC Hydro, are planned, operated and managed by the British Columbia Transmission Corporation ("BCTC"), a provincial Crown Corporation created under the *Transmission Corporation Act*. BCTC was constituted in May 2003 and began operation on August 1, 2003.

The demand on BC Hydro's system for customers connected to the integrated system or "grid" in F2006 was 9,617 MW and the total gross energy requirement was 57,336 GWh. The off-grid NIA demand added another 325 GWh to the total gross requirement. BC Hydro has programs to attempt to manage its load through DSM initiatives to encourage energy efficiency. The Power Smart program was launched in 1989; currently the DSM initiatives provide around 500 GWh of "savings" per year.

2.2 Rate Design History

Since the 2007 RDA is the first comprehensive rate design application since 1991, relevant Commission proceedings and findings between 1991 and 2007 are summarized in this Section to provide a backdrop for the Commission Panel Determinations in this Decision.

On May 14, 1987 BC Hydro filed with the Commission Dual Fuel Interruptible Service ("E-Plus") discount rates in response to restrictions imposed by the Bonneville Power Administration on its transmission intertie to California and the resultant uncertain export markets. The rate design history of E-Plus rates, which were subsequently approved by the Commission, is described in more detail in Section 4.2.2.

2.2.1 Rate Design Application – October 28, 1991

The rate design application BC Hydro filed on January 15, 1991 was amended by another filing on October 28, 1991. The 1991 application was filed to fulfill two regulatory criteria: that BC Hydro's rates must be fair, just and reasonable, and that the rates serve the specific objective of SD3 to the Commission. As discussed in Section 1.1.2 above, a special emphasis in SD3 was on conservation and the efficient use of electricity. As a result of these criteria, the fundamental objective of the 1991 application was to change the structure of the price levels then in place, in a manner that served to alert customers to the rising cost of future power (Exhibit B-3, ESVI IR 1.14.0 Attachment 4, April 24, 1992 Decision, p.13).

In its 1991 rate design application, BC Hydro made reference to the special rate categories for all customers in the NIA, defined in its tariff structure as Zone II. BC Hydro stated that it would submit a rate design proposal for Zone II (April 24, 1992 Decision, p.8).

In rendering the decision on the 1991 rate design application, the Commission made some observations on the application itself and on evidence put forward by BC Hydro that it intended to institute a monitoring program in order to improve traditional load research, and gain information on customer reaction to both pricing and DSM programs:

> "… B.C. Hydro's Rate Design Application generally deals with principles apart from the specific changes for which they have applied. In the residential, commercial and industrial sectors a high level of uncertainty regarding the future exists. Not only is the proposed rate design dependent on potential revenue requirement increases, but also on the uncertain level of acceptance of the IRP [Integrated Resource Plan] by industrial customers and by the impact of rate changes on other classes."

> "It is clear from the evidence that the monitoring program is essential to future determinations in the rate design proposal. Without the program, B.C. Hydro cannot make informed decisions." (April 24, 1992 Decision, p. 71)

These observations led the Commission to determine that the objective of smooth, stable and predictable rate increases could not be adequately examined in a concrete and specific manner in its decision (April 24, 1992 Decision, pp. 12-13). The findings the Commission made include:

- The data upon which the FACOS study relied was of insufficient quality to allow for narrower bounds to surround the revenue cost ratios such as the 10 percent bounds which the Commission has accepted in the past (April 1992 Decision, pp. 15, 16)
- The Commission agreed with BC Hydro that the declining block rate structure was inappropriate in light of BC Hydro's resource realities and the direction of government policy (April 1992 Decision, p. 16)
- It was clear from the evidence that the monitoring program was essential to future determinations in the rate design proposal. Without the program, BC Hydro could not make informed decisions (April 1992 Decision, p. 71).

2.2.2 1993 Revenue Requirements Application - February 19, 1993

In its 1993 revenue requirements application ("1993 RRA"), BC Hydro applied for a permanent general rate increase to all customer classes. The application referenced the provisions contained in SD8 concerning rate increases and rate design to achieve conservation and efficient energy use.

In its December 7, 1993 Decision on the 1993 RRA, the Commission encouraged BC Hydro to further pursue the integration of its Power Smart program with its rate design initiatives so that "these two policies would complement one another and help to achieve the objectives of SD8". The decision stated that the Commission expected significant evidence of achievement of this goal at the next hearing (Exhibit B-3, ESVI IR 14.0 Attachment 2, December 7, 1993 Decision, pp. 49, 50).

In that same decision, the Commission rejected BC Hydro's proposal that no residential customer's bill would increase by more than the amount of the general increase plus 2 percent and that no customer's bill should decrease as a result of rate flattening. The Commission directed that the entire amount of the revenue requirement increase applicable to residential customers be applied to the trailing block rate then in force. BC Hydro was directed to achieve flat rates for residential customers in two approximately equal steps, commencing with consumption from January 1, 1994 (December 7, 1993 Decision, pp. 53-54; Exhibit B-3, BCUC IR 1.44.3).

The Commission also directed BC Hydro to achieve flat rates for general service ("GS") customers by the start of the 1995/96 fiscal year, with the first step to commence effective with consumption starting January 1, 1994. BC Hydro was also directed to maintain articulation between the general service rate schedules serving customers taking under 35kW (RS 1220), and customers taking 35kW and over (RS 1200), to ensure that customers at the crossover point are indifferent to whether they are served on one rate schedule or the other.

The rate structure currently in place has been unchanged since April 1, 1996 (December 7, 1993 Decision, pp. 54-55; Exhibit B-3, BCUC IR 1.44.3; BC Hydro Final Argument, p. 43).

2.2.3 1994/95 Revenue Requirements Application - February 11, 1994

On February 11, 1994, BC Hydro applied to the Commission for Orders approving a 2.8 percent permanent increase in electric rates effective April 1, 1994, for the fiscal year ending March 31, 1995, based upon rate design proposals set out in that application. The application again referenced SD8 and the provision contained in that Special Direction concerning rate increases and rate design (Exhibit B-3, ESVI IR 14.0, Attachment 6, November 24, 1994 Decision, p. 2).

BC Hydro submitted that it was not possible to comply with the Commission's Order to achieve flat rates for Rate Schedule 1200 (Large General Service) while maintaining appropriate articulation with Rate Schedule 1220 (Small General Service), and collect the appropriate share of revenue requirement from each class of general service customer. BC Hydro proposed, for April 1, 1995, that the RS 1200 energy charge be a two-step declining block rate. In addition, BC Hydro proposed to maintain the inverted block structure for the demand charge, to help levelize the energy charge for a customer at the boundary between the two rate classes RS 1200 and RS 1220. BC Hydro submitted that its latest Fully Allocated Cost of Service ("FACOS") study, based on 1991/92 data, showed that there was no undue cross-subsidization between customer classes. It also submitted that it undertook new cost of service studies every two years, and had a monitoring program to feed better information into the studies, and was reviewing the methodology it used.

In its decision on the 1994/95 RRA, the Commission directed BC Hydro to extend the time frame over which a flat rate for RS 1220 (35 kW and over) is achieved by one year to fiscal 1996/1997. The Commission also directed BC Hydro to file a copy of the latest completed FACOS (November 24, 1994 Decision, pp. 77-78).

With respect to the distribution extension policy for connection to the BC Hydro distribution grid, the Commission directed BC Hydro to review the principles underlying its distribution extension policy to ensure that they are compatible with its Integrated Resource Planning ("IRP") methodologies. The Commission proposed to undertake a general review of extension policy, within a multi-utility framework, during the following year (November 24, 1994 Decision, p.73).

Other rate design issues raised in the course of the revenue requirements hearing included the appropriate application of time-of-use and seasonal rates. The Commission also directed BC Hydro to file a report with the Commission by February 28, 1995 to describe the various intra-class rate design options available to BC Hydro (November 24, 1994 Decision, p. 78).

2.2.4 Utility System Extension Test Guidelines - September 6, 1996

The Commission held a multi-utility review of system extension policies in 1995. The utilities that made up this generic hearing included BC Hydro, FortisBC (then West Kootenay Power Ltd.), Terasen Utilities (which included the former BC Gas Utility Ltd. and the former Centra Gas British Columbia Inc.), Princeton Light and Power Company, Limited (now part of FortisBC), and Pacific Northern Gas Ltd.

The primary purpose of the generic hearing was to determine if opportunities existed to improve the fairness and efficiency of system extension policies and to make them more consistent among utilities. The hearing resulted in the issuing of a set of voluntary guidelines to assist the utilities with information that may be required by the Commission in the review of system extension filings and system extension tests (“SET”) submitted by the utilities.

Some of the key recommendations in the guidelines include: (1) that the utilities develop a discounted cash flow (“DCF”) based SET, (2) that the utilities conduct evaluations of system extensions both from a social perspective and a utility perspective, (3) that system improvement costs be consistently applied in SET and in connection fees on a cost causation basis, and in a manner that does not add unnecessary complexity, (4) that connection charge be designed to recover the full cost of service connection, and (5) that *if a contribution-in-aid is required, it would be borne by those customers who benefit from the system extension*. Specifically, the Commission recommended that, insofar as practical, the analysis of system extensions be based on full incremental costs and benefits (emphasis added).

2.2.5 Rate Freeze - 1996 to 2003

BC Hydro’s rates were legislatively frozen from 1996 until the rate freeze ended effective March 31, 2003. The end of the rate freeze allowed the implementation of Policy Action #5 of the 2002 Energy Plan, which provided that “the BC Utilities Commission will once again regulate BC Hydro rates” .

2.2.6 Heritage Inquiry

On March 25, 2003, the Province, by OIC 0253, issued the Terms of Reference for an Inquiry relating to a Heritage Contract for BC Hydro’s Existing Generation Resources and to Stepped Rates and Transmission Access. In response, the Commission issued Commission Order No. G-23-03 dated April 1, 2003 to direct BC Hydro to file a proposal with respect to a Heritage Contract for BC Hydro’s Existing Generation Resources and regarding Stepped Rates and Transmission Access. The Commission’s Report and Recommendations on the “Inquiry Into a Heritage Contract for BC Hydro’s Existing Generation Resources and Regarding Stepped Rates and Transmission Access”, dated October 17, 2003 and HC2 subsequently issued with an effective date of April 1, 2004 were addressed in Section 1.1.2 above.

2.2.7 2004/05 and 2005/06 Revenue Requirements Application - December 2003

The F05/F06 RRA filed in December 2003 was made in the context of policy developments affecting the electric industry in BC at the time, in particular the provincial government's 2002 Energy Plan. Relevant rate-related Policy Actions established the legislated Heritage Contract, the continuing electricity trade benefit to BC Hydro rate payers, and that *"new rate structures will provide better signals to large electricity consumers for conservation and energy efficiency"* (emphasis added).

In the F05/F06 RRA BC Hydro did not propose any new rate forms such as stepped rates for industrial and large commercial customers, nor any re-design of any of its current rates, including its E-Plus rates (Rate Schedules 1105, 1205, 1206 and 1207), or its rates for customers in the NIAs. At the time, BC Hydro contemplated that it would deal with stepped rates in an application it expected to file in late 2004 or early 2005, and with all other rate design issues in an application it expected to file in early 2005.

At the oral public hearing conducted to examine the F05/F06 RRA, issues such as SET, rates for the fixture component of street lighting, Standard Charges of the Electric Tariff and Zone II Special Contract Rates were raised. BC Hydro took the position that a rate design hearing was the more appropriate forum to look at all the electricity tariffs for electricity and other costs (October 29, 2004 Decision, pp. 165, 167, 171).

2.2.8 Application For a Net Metering Tariff – November 3, 2003

Around the time the F05/F06 RRA was filed, in response to a Commission directive, BC Hydro proposed a net metering tariff. The directive was a result of interest expressed by stakeholders and Policy Action #20 from the 2002 Energy Plan. Policy Action #20 represented a voluntary goal for electricity distributors to pursue at least 50 percent of their new power supply from BC Clean resources. The application for a permanent Net Metering Tariff (Rate Schedule 1289) was approved on March 12, 2004 (Commission Order No. G-26-04).

2.2.9 Transmission Service Rate Application – March 10, 2005

BC Hydro's application to introduce a stepped rate and a time-of-use rate for transmission voltage customers was filed in March 2005. The application was based on (1) Policy Actions #14 and #21 of the 2002 Energy Plan and (2) the Government's Response to the Commission Recommendations #8 through #15 from the Inquiry into a Heritage Contract. The Energy Plan Policy Actions are related to large electricity consumers being provided incentives to purchase from IPPs or self-generate, *and being provided with better price signals from new rate structures for conservation and energy efficiency*. The Government Response to the Commission's Recommendations related to the design and implementation of the stepped and time-of-use rates (emphasis added).

A negotiated settlement process ("NSP") was established to review the application. Some of the issues arising from the NSP were: Customer Base Load ("CBL") criteria, retail access provisions, a general rate design application to address any proposed modifications to standby and maintenance rates, exemption from stepped rates, and Tier 2 rates. The NSP resulted in a Transmission Settlement Agreement dated June 15, 2005 which was approved by Commission Order No. G-79-05.

2.2.10 Review of the 2006 Integrated Electricity Plan ("IEP") and 2006 Long Term Acquisition Plan ("LTAP") and the F07/08 RRA

The rate design application by BC Hydro, contemplated for filing with the Commission in early 2005 had not yet been filed by the time the F07/F08 RRA was filed. At a joint procedural conference held in August 2006 to consider the 2006 IEP and LTAP and the F07/08 RRA, the Commission considered submissions on whether a rate design application should be filed. This process resulted in the issuance of an Order to BC Hydro to file a rate design application within thirty calendar days of the date of the F07/F08 revenue requirement decision (Commission Order No. G-96-06).

The F07/F08 RRA was approved by Commission Order No. G-143-06, dated November 10, 2006 and consequently BC Hydro was required to file its rate design application by December 11, 2006. BC Hydro applied for a reconsideration and variance of paragraph 2 of Order No. G-96-06 and requested instead an order to direct BC Hydro to file a rate design application by March 15, 2007.

By Order No. G-148-06, the Commission ordered, in part, that BC Hydro file its rate design application by March 15, 2007.

2.3 Application and Orders Requested

2.3.1 Application

BC Hydro's 2007 RDA, filed on March 15, is its first general rate design application since 1991 and only the second such application in BC Hydro's history. BC Hydro states that "the purpose of the Application is to update BC Hydro's rates and Terms and Conditions of Service ("Terms and Conditions") to reflect current conditions and generally accepted rate design criteria … with the main focus on fairness, efficiency and simplicity." (Exhibit B-1, pp. 1-2)

The 2007 RDA is based on BC Hydro's F2008 revenue requirement from its F07/F08 RRA as approved by the Commission in Order G-148-06, as amended by Order No. G-17-07 regarding the F2008 rate of return on equity for BC Hydro. BC Hydro's total revenue requirement and the proposed rates and fees in the 2007 RDA must be equal (Exhibit B-1, p. 2). The new rates and fees are proposed to be effective on April 1, 2008 in order to give advance notice to customers of the new rates. The total revenue requirement to be recovered from rates for F2008 is $2,836 million (Exhibit B-1, p. 24; Appendix A Schedule 4.1).

A profile of the Applicant's domestic sales volumes and domestic revenues by rate class is provided below.

Table 2-1
DOMESTIC REVENUES AND SALES VOLUMES - F2008

	$ million **Plan**	**GWh** **Plan**
Residential	1,092.0	16,999
Light industrial & comm.	1,033.4	18,700
Large Industrial	592.2	16,622
Irrigation	4.2	96
Street Lighting	22.9	207
Other Utilities	64.5	1,537
TOTAL	2809.2	54,161

Source: Exhibit B-1, Appendix B, Schedule 14.0, p. 42

With the exception of a rate restructuring proposal to flatten the charges for Large General Service customers and proposals to phase out E-Plus rates, amend the distribution extension policy and update standard charges, the 2007 RDA involves only basic rate rebalancing, which could be described in simplistic terms as "dividing the revenue pie". BC Hydro states in its Application that it is "currently developing a long term rate strategy that will be informed by the 2007 Energy Plan and that will set the course for future rate changes and new rates that are designed to promote energy conservation and load management" (Exhibit B-1, p. 3).

2.3.2 Orders in Respect of the Application and the Proceeding

BC Hydro applied for an order from the Commission pursuant to the UCA, and in particular sections 58 and 61 thereof, approving a number of changes to the Rate Schedules and the Terms and Conditions attached. A summary of the specific relief BC Hydro seeks in the Application provided in BC Hydro's Opening Submissions is as follows:

- In particular, BC Hydro seeks approval of all the changes indicated in its tariff sheets attached to the Application (Exhibit B-1) at Appendix D, effective April 1, 2008;
- the proposed amendments to BC Hydro's tariff sheets at Appendix D include:

a) the increase to the residential rate arising from the rate rebalancing exercise;

b) a concomitant decrease in the Small General Service rate;

c) the first-year change of the proposed three year phase-in of the restructuring of the Large General Service rate;

d) the first-year change to the proposed five year phase-in of the rebalancing of the irrigation rate;

e) the proposed phase-out of the E-Plus rates; and

f) a number of minor changes to the tariff, as indicated.

- BC Hydro also seeks approval of the changes indicated in its tariff sheets attached to the Application at Appendix E, effective April 1, 2009; April 1, 2010; April 1, 2011 and April 1, 2012, being:

  a) the proposed second and third year changes to the GS>35kW rate, to be adjusted to reflect the cumulative impact of any general rate changes approved by the Commission prior to the effective dates of April 1, 2009 and April 1, 2010, respectively; and

  b) the proposed second to fifth year changes to the irrigation rate, to be adjusted to reflect the cumulative impact of any general rate changes approved by the Commission prior to the effective dates of April 1, 2009, April 1, 2010; April 1, 2011; and April 1, 2012, respectively;

- BC Hydro also seeks approval of the changes indicated to the Terms and Conditions of its tariff sheets, including the proposed change to its SET, at Attachment G to the Application, effective April 1, 2008; and to charge customers, for the period April 1, 2008 to June 30, 2008, the lower of the extension fee payable under the proposed extension charge and the current extension charge (Exhibit B-24, pp. 1-2)

2.4 Conduct of the Hearing

This section of the Decision deals with the evolution of the proceeding from a single phase, to a multi-phased process, in response to the issues that arose during pre-hearing discovery , and the Commission Panel's determinations as to how to best accommodate the interests of the various Parties to the proceeding.

2.4.1 Pre-Hearing Matters

On May 4, 2007 the Commission Panel held a Procedural Conference to hear submissions on the regulatory process for the review of the 2007 RDA, including the format of the hearing and alternative review processes. A majority of Intervenors supported BC Hydro's recommendation of a Negotiated Settlement Process ("NSP") for the 2007 RDA. An exception was the City of Westminster, which preferred an oral public hearing because the rate design issues have not been before the public since 1991 and because "an oral hearing creates a public record and makes it straightforward for communications between the city and its rate payers, and the city and its electricity supplier" (T1:35).

By Order No. G-50-07 dated May 8, 2007 (Exhibit A-4) the Commission established an oral public hearing process because after a hiatus of over 16 years, and given the foundational nature of the Application, the need for transparency and the creation of a public record were paramount. The Commission Panel found that an NSP, by its very nature, was unlikely to fulfill those needs. Furthermore, the submissions from the Applicant and a majority of the Intervenors left the Commission Panel in doubt as to whether all the issues could be settled by an NSP (Exhibit A-4, Appendix B).

2.4.2 The Staff Issues List

Pursuant to Order No. G-50-07 the Staff Issues List was issued July 3, 2007 (Exhibit A-19). The issues were grouped as follows:

1. Policy, Regulatory Context, and Rate Design Objectives
2. Cost of Service Study
3. Rate Restructuring
4. Distribution Extension Policy
5. Non-Integrated Area – Zone II Customers
6. E-Plus Customers

Comments on the Staff Issues List

BC Hydro in its letter of July 5, 2007 (Exhibit B-21) commented in detail both as to policy, and particulars, proposed that all issues related to Zone II rates, including those raised by the Heiltsuk Tribal Council and Shearwater Marine Limited ("Heiltsuk") be severed from the current RDA and be the subject of a separate application by BC Hydro on or before December 1, 2007. As a matter of policy, and as context for its detailed comments, BC Hydro submitted that "where an issue does not reflect a position taken by an intervenor in evidence that is contrary to a BC Hydro proposal it should not be an issue for the oral phase of this proceeding and should be struck from the staff Issues List."

The Joint Industrial Electricity Steering Committee ("JIESC") in its July 6, 2007 letter, submitted that the proposed BC Hydro policy was without precedent in the Commission's or other proceedings and would infringe the rights of the Intervenors and the Commission to test the Applicant's case, whether or not they call evidence (Exhibit C18-15).

The Commercial Energy Consumers of British Columbia *et al* ("CEC") in its July 6 letter supported the JIESC position (Exhibit C12-5).

The B.C. Old Age Pensioners' Organization *et al.* ("BCOAPO") in its July 6, 2007 letter, submitted that BC Hydro's position was patently incorrect and in conflict with procedural fairness (Exhibit C6-11).

The Heiltsuk in its letter of July 5, (Exhibit C23-11) proposed the addition of further issues in the Zone II/NIA category, and, in its letter of July 6 (Exhibit C23-12), responded to the above BC Hydro submissions with respect to severing those issues from this proceeding. Specifically, the Heiltsuk submitted that while it did not purport to represent the cohort of customers in Zone II and the NIA's, some or most of the NIA issues bore on Bella Bella but the converse was not true, and it did not agree with BC Hydro that consideration of the issues raised by the Heiltsuk should be deferred.

The Commission Panel Decision on the Issues List

Pursuant to the Commission Panel's review of the Staff Issues List, and consideration of the submissions of the parties, the Commission issued the Commission Panel Hearing Issues List ("Issues List") for the proceeding on July 6, 2007 (Exhibit A-23). The issues, as amended, were grouped in the following categories:

1. Policy, Regulatory Context, and Rate Design Objectives
2. Cost of Service Study
3. Rate Restructuring
4. Distribution Extension Policy
5. E Plus Customers
6. Non-Integrated Area – Zone II Customers
7. "Bella Bella NIA" Customers

The cover letter to the Commission Panel's Hearing Issues List noted that the items in Sections 6 and 7 were subject to the Commission Panel's determinations on the motions then before the Commission Panel.

2.4.3 Commencement of the Oral Phase of the Proceeding – July 9, 2007

2.4.3.1 Heiltsuk Preliminary Motions

Firstly, by letter of June 28, 2007 the Heiltsuk asked the Commission to direct BC Hydro and the Central Coast Power Corporation ("CCPC") to produce copies of the Energy Purchase Contract ("EPA"), Lease Agreement and any other relevant contracts relating to the supply of power by CCPC to BC Hydro for service in the Bella Bella NIA (Exhibit C23-7).

Secondly, by letter dated July 4, 2007 the Heiltsuk asked the Commission to order BC Hydro to respond without delay to a list of some 25 of its IR No. 3 (Exhibit C23-10).

In response, BC Hydro, by letter of July 5, 2007, (Exhibit B-21), proposed that all Zone II matters, including the Heiltsuk issues be the subject of a separate application to be brought by BC Hydro on or before December 1, 2007 (T2:71).

2.4.3.2 Panel Process to Deal With the Heiltsuk Motions

The Chair invited submissions on the following questions:

"Does BC Hydro wish to make the submission that Zone II rate issues be severed from this proceeding? If the answer is "Yes", the Panel will hear submissions as to the order in which it should hear the three submissions. If the answer is "No," the Panel will proceed to hear the two motions put forward by Heiltsuk" (T2:72).

BC Hydro affirmed the position it had taken in Exhibit B-21, that the NIA matters be the subject of a separate proceeding, but submitted that the questions are integrally related (T2:76-77).

BCOAPO submitted that Heiltsuk issues are severable from the general question of the NIA (Zone II issues) and that the record is more fulsome with respect to the Heiltsuk matters than with the NIA matters in general and that the Bella Bella (Heiltsuk) situation ought to be heard and addressed now (T2:78-80).

The Heiltsuk submitted that while a general review of Zone II rates might well be appropriate, it should in no way preclude the examination of the issues specific to the Heiltsuk service region and those issues required looking at, to some extent, Zone II and NIA's generally (T2:84).

CCPC submitted that it had had inadequate notice of the issues and inadequate time to prepare (T2:90-91), agreed with BC Hydro's reasons as outlined in Exhibit B-19, (third paragraph) why this motion should be denied, and requested that all issues on the Issues List that related to CCPC be dismissed (T2:94).

The Heiltsuk in reply pointed to the extensive record in IRs and other correspondence that constituted notice to CCPC and established the relevance of the material sought through the motions (T2:100,105).

BC Hydro, while taking no position on whether hearing the Heiltsuk motion to compel production of CCPC's EPA with BC Hydro should proceed (T2:109), brought to the Commission Panel's attention previously undisclosed correspondence between BC Hydro and CCPC that bore directly on the matters comprising the motions and the parties' positions on them, specifically, a letter from BC Hydro to CCPC of May 8, 2007, (entered as Exhibit B-25) in which BC Hydro stated its preparedness to disclose the agreement between BC Hydro and CCPC in response to the Heiltsuk IRs , and, out of an abundance of caution, invited CCPC to provide BC Hydro with any documentation that would support a claim to confidentiality (T2:114).

The Heiltsuk, in response to this disclosure, pointed out that the letter contained a deadline for response by CCPC to BC Hydro, failing which BC Hydro would release the contract, which was apparently not complied with (T2:117).

CCPC in response submitted that its principals were out of the country at the time of receipt of the letter, that it responded to the Commission by letter of May 26 (attachment to Exhibit A-7) objecting to the release of the information, but that it had indicated a willingness to respond to questions about its EPA with BC Hydro in that letter (T2:118, 105).

The Heiltsuk contended that in response to CCPC's position as attached to the Commission's letter of May 30 (Exhibit A-7), it had provided an exhaustive list of its questions and reasons for them by letter to the Commission dated June 28, 2007 (Exhibit C23-7; T2:105).

In reply CCPC submitted that the Heiltsuk questions were directed to the Commission rather than to CCPC directly (T2:108).

The Commission Panel Decision in Respect of Hearing the Motions.

The Commission Panel found that the Heiltsuk issues were properly before the proceeding, that CCPC had received ample notice that the EPA between it and BC Hydro was the subject of this proceeding before the Commission, and accordingly decided to hear submissions on the Heiltsuk motion that the EPA be produced by BC Hydro (T2:120).

2.4.3.3 Submissions on the First Heiltsuk Motion

The Heiltsuk submissions dealt with three principal themes: the importance of a clear understanding of rates as a primary objective of a rate design hearing, the obligation of the Commission to enquire into a *prima facie* case of unjust, unreasonable, or unduly discriminatory rates, and the proper test of relevance (T2:122).

The Heiltsuk submitted that the relief sought by the motion was the documentation of the agreement between BC Hydro and CCPC and amendments to it as well as related documentation, given the uncertainty as to the form and status of the contract and the references to it in BC Hydro's NIA Business Strategy (T2:123-124).

The Heiltsuk confirmed that its motion relied on its Exhibits C23-7, and C23-9 (T2:127), and cited as authorities for its position sections 58 (1),(2); 59 (3)-(5); 60, of the Act, all as cited by BC Hydro in Exhibit B-24, as well as sections 61 (1)-(3) and 25 and 28, noting that the latter two apply to CCPC as well as BC Hydro (T2:128).

The Heiltsuk particularized its *prima facie* case for unjust, unreasonable and unduly discriminatory rates in Bella Bella, with reference to Hansard excerpts, (Exhibit C23-13), relating the history of generation in Ocean Falls, its apparent low cost structure, and the transfer of the generating assets in working order to CCPC in 1986 or 1987, albeit without the transmission line from Ocean Falls to Bella Bella (T2:130). The Heiltsuk asserted that this historically low cost power was being supplied by BC Hydro to the Bella Bella NIA at "the highest rates charged by it in BC" (T2:130), and accordingly that an examination of the required contracts was in order.

The Heiltsuk submitted that beyond the above referenced sections of the Act, the Issues List itself (Exhibit A-23), supported its position, notwithstanding the caveat that the issues in Sections 6 and 7 were subject to the Commission Panel's determination of the motions before it, (T2:135). As well, the interplay between and among the various IRs of BC Hydro by the Commission and the Heiltsuk, and the Commission's and BC Hydro's of the Heiltsuk, along with the Heiltsuk evidence, Exhibit C23-4, further supported the relevance of the contracts (T2:136).

The Heiltsuk contrasted the current Special Contract rate of some 17 cents per kW.h in Zone II, and the methodology that would see it rise to some 25 cents/kW.h, all else equal, and the Zone II rates themselves, with the F 2006 call reference price of some 8.8 cents/kW.h (T2:139). The Heiltsuk further pointed out that, after the cost of energy from CCPC, the second largest cost component was the BC Hydro backup diesel generating station which provides less than one percent of the annual supply to Bella Bella and existed solely to back up the supply from CCPC, (T2: 140), and that the questions of the reasonableness of those costs, and who should be bearing them, was deserving of inquiry (T2:141).

The Heiltsuk also pointed to the dichotomy that, under Order No. G-40-86 which exempted CCPC from regulatory overview and which was amended by Order No. G-30-02, industrial rates in Ocean Falls could be negotiated, but that they could not exceed the Zone I tariffs, (T2:142), while Zone II customers supplied principally from the same hydro generating assets, were being charged rates based on diesel generation (T2:142). Further, the Heiltsuk submitted that the answers to these questions could only be found in the requested contracts (T2:142).

The Heiltsuk pointed out that CCPC had provided no specifics, only oblique references as to the reasons it viewed the contracts as confidential, and that the Heiltsuk had responded positively, in the form of its list of questions of June 28, 2007 (Exhibit C23-7) to CCPC's indication in its letter of May 26, 2007 (Attachment to Exhibit A-7), of its willingness to be responsive to questions, but there had been no response to those questions (T2:144-5).

The Heiltsuk also asked that the Commission Panel consider that this first motion and submissions to it constituted an implicit “Complaint” under section 25 of the UCA, on the grounds of unreasonable or unreasonably discriminatory service, (T2:147), advised that the Complaint applied to both BC Hydro and CCPC, and further, that the best way to begin to address the Complaint was to order production of the required requested contract (T2:148).

The Heiltsuk further pointed to a second Complaint as referenced in its evidence, Exhibit C23-4, at page 9, arising from Order No. G-30-02, attached to that evidence. Specifically, paragraph D of that order provides that on a complaint by an interested party, the Commission may review whether the exemption for CCPC [from the Act] continues to be in the public interest. The Heiltsuk indicated that the status and future pursuit of that Complaint could be contingent on the production of the contracts (T2:148).

BCOAPO submitted that the matter was within the scope of the proceeding given the Issues List, that the relevance of the document had been established given its role in driving a rate that was within the scope [of the proceeding], (T2:155), and that the only remaining issue was procedural in relation to the potential confidentiality of the document. To the latter point, BCOAPO submitted that disclosure should be subject to undertakings by the receiving party not to disclose it publicly (T2:156).

BC Hydro in response submitted that the relevance of the document was not absolute, but had to be considered in light of the passage of time since the original request for it, and the stage to which the proceedings had progressed, and the implications for delay that might arise if it were now produced (T2:159).

BC Hydro also responded that contract did not drive the rate in Bella Bella, but that that rate was a postage stamp rate for all the NIA’s, regardless of their particular supply circumstances (T2:160).

BC Hydro further noted the complexity added to the proceedings by the Heiltsuk complaints, stating that BC Hydro would require additional time to put up a witness panel, and re-emphasized the intertwining of the issues (T2:163).

BC Hydro directed the Commission Panel's attention to SD10 and the Remote Communities Regulation (T2:175). BC Hydro put forward the view that the definitions of the Integrated and Non-Integrated Areas (NIA's) in SD10 bear directly on the motions before the Commission Panel in that Bella Bella is included in the areas defined as Non-Integrated (T2:178), and accordingly, since BC Hydro's tariff definition of the Zone II area to which it applies perfectly matches the NIA area as defined in SD10, that any specific relief sought by the Heiltsuk could be inconsistent with SD10, and could only be achieved, on a theoretical basis, within a construct of what Zone II or NIA rates should look like (T2:179-180).

BC Hydro stated that notwithstanding the new issues raised by SD10, and their intersection with the motions before the Commission Panel, it was, and still is prepared to deal with the Heiltsuk issues on the record as it existed; i.e., without the CCPC documents, without the further IRs, and without the general NIA issues on the Issues List (T2:182).

BC Hydro also tabled its changed view as to the confidentiality of the contract documents from that in its letter to CCPC of May 8 (Exhibit B-25), based on the process involved in amending the terms of the contract after the first 10 years of its contemplated 20 years of operation, which, in the absence of intervention by the Commission at that time, involved a lengthy arbitration, (T2:183), and ultimately a negotiated settlement between CCPC and BC Hydro outside of the arbitration proceeding. This settlement not only covered the last ten years of the agreement, but also extended it for a further ten years. BC Hydro indicated that it had currently become aware of a "provision" in one of the exchanges of correspondence that "one could plausibly base a confidentiality argument on" (T2:184).

BC Hydro raised a concern that any cross examination concerning the contract amendments and extension would be complex and time consuming given the voluminous nature of the documentation of the arbitration hearing and the matters it covered, and reiterated its position that the Heiltsuk issues should be put over to the general NIA hearing BC Hydro had proposed in order to maintain the timetable of the current proceedings, and that the current proceeding should be confined to the matters under Items 1 through 5 on the Issues List (T2:192). BC Hydro further pointed out that it had not provided notice to customers in the NIA's that policy level issues affecting them would be the subject matter of this proceeding (T2:193).

BC Hydro subsequently confirmed that the amendments to the contract to establish the rates for the last ten years of the contract, and to extend it for a further ten years, were documented in an "exchange of business correspondence" between CCPC and BC Hydro and could be accessed without recourse to the arbitration proceeding record (T2:203).

BC Hydro also confirmed that, with respect to the specific motion before the Commission Panel, that while it is inextricably linked with other issues, "requiring BC Hydro to produce the contract and limiting the scope of inquiry with respect to it is manageable" (T2:204).

CCPC generally adopted the positions advanced by BC Hydro with respect to the relevance and confidential nature of the contract, and emphasized the separate nature of CCPC from any of the parties affected by the rates at issue in the proceeding.

CCPC also indicated that if the Heiltsuk matters were to be heard in this proceeding, that it would be an active participant and accordingly was intending to apply for Intervenor status (T2:226).

In reply the Heiltsuk addressed the apprehended or pending nature of its two complaints as referenced earlier (T2:228-30).

Commission Counsel pointed out that neither complaint to this point had been referred to the Commission in the usual form (T2:230), which the Heiltsuk acknowledged, pointing out that it was not yet prepared to proceed (T2:231).

BC Hydro recorded its view that the utility being complained about in Section 25 was CCPC, not BC Hydro (T2:232). The Heiltsuk contested BC Hydro's view on the basis of "the evidentiary context of BC Hydro providing service in a community [Bella Bella] that is physically linked to another community [Ocean Falls] by a transmission line that shares a single generation source but has markedly different rates applied by the two utilities [BC Hydro and CCPC] for power that is produced from the identical facility, from the same facility [CCPC]" (T2:232).

The Heiltsuk further submitted that section 58 of the Act not only contemplates a hearing and potential relief for an interested party complaining in respect of an unjust, unreasonable, or unduly discriminatory rate for service by a public utility, but also that BC Hydro considers section 58 an essential section for purposes of this Rate Design Application (T2:234).

In reply to BC Hydro's submissions to the motion, the Heiltsuk re-emphasized that the CCPC rate to BC Hydro is the largest component by far of the cost of energy to service the Bella Bella NIA (T2:235).

The Heiltsuk also stated that BC Hydro's concerns with respect to potential delay and inconvenience arising if the contract were produced were speculative, and should have no bearing as to whether production itself were right or wrong (T2:236). Further, the Heiltsuk rejected BC Hydro's view that the only relief being sought by the Heiltsuk was Zone I rates for Bella Bella (T2:236-237).

With respect to the SD10 matters raised by BC Hydro, the Heiltsuk stated that the definitions were not as clear cut as represented by BC Hydro, and submitted that such a virtual match with BC Hydro's Zone II geographic definitions as represented by BC Hydro was in fact the case, and that SD10 addressed substantive matters such as the promotion of biomass based power, and the cost recovery for the contemplated extensions of service to the Remote Areas, which had much broader implications than just for the NIA's, and accordingly SD10 did not by itself provide any justification for not dealing with the Heiltsuk issues in this proceeding (T2:243-247).

2.4.3.4 Submissions on the Second Heiltsuk Motion

The Heiltsuk submitted that its argument for the Commission Panel to grant the second motion directing BC Hydro to respond to certain specific IRs in Exhibit C 23-8 was essentially covered by its submissions to the first motion (T2:258).

BC Hydro submitted that the issues raised were of marginal relevance, and addressed them in some detail, pointing out where, in some cases, other processes or commitments by BC Hydro addressed the matters at issue (T2:260-8).

In reply, the Heiltsuk briefly addressed five of BC Hydro's points (T2:269-270).

2.4.3.5 Commission Panel Decision in Respect of the Status of CCPC – July 10, 2007

The Commission Panel heard submissions from CCPC applying for late Intervenor status in the proceeding, (T3:273; 282-85). The Heiltsuk made a qualified opposition to the application (T3:273-82).

Pursuant to consideration of those submissions, the Commission Panel granted intervenor status to CCPC, noting CCPC's stated limited interest in the proceeding, and directed that, given the stage of the proceeding, CCPC was entitled to cross-examine, file evidence, and make final argument. Further, any CCPC evidence was to be filed and distributed by July 24 and was limited to addressing the items in Sections 6 and 7 of the Issues List (Exhibit A-23; (T3:287).

2.4.3.6 Commission Panel Decision in Respect of the Heiltsuk Motions – July 10, 2007

Following consideration of the submissions from the parties, the Commission Panel decided as follows:

- To proceed with the present oral hearing process and hear the issues in Sections 1 through 5 of Issues List by July 20, 2007 (T3:288); and

- To defer its decision on the Heiltsuk motion to compel BC Hydro disclosure of the agreements between it and CCPC pending the Heiltsuk, CCPC, and BC Hydro attempting to respond to the 33 questions listed by the Heiltsuk in Exhibit C23-7, items (a) to (gg) in response to CCPC's offer of May 26, as attached to Exhibit A-7. The parties were to report to the Commission on or before July 31, 2007 on the results of their efforts, following which the panel would rule as to what further action if any is required of the parties (T3:288).

BC Hydro was directed to respond only to the following for the Heiltsuk's 25 IRs set out in its motion in Exhibit C23-10 (T3:289-290):

- 3.49.1 through 3.49.4, and 3.44.1, concerning revenues and costs;
- 3.40.1 and 3.40.6 concerning the NIA business plan appendices, and further that
- 3.42.1 concerning the take or pay provision is referred to the process to deal with the 33 questions described above

The items covered in Sections 6 and 7 of Issues List would be heard at a subsequent second phase of the oral public hearing, starting on or around August 13, 2007. Parties were to submit their comments on or before August 6 so that the Commission Panel may issue a revised list, if necessary, by August 9, 2007 (T3:292).

2.4.3.7 Submissions in Respect of the Second Phase of the Hearing – July 13, 2007

BC Hydro submitted that it could put up a witness panel in early September to deal with the Heiltsuk complaint and the NIA issues that bore directly on it (T6:1010) but that it would be early October before it would be in a position to deal with the Zone II Special Contracts Application as noted in its application for interim rates by letter dated July 11, 2007 (Exhibit B-37; T6:1014).

BC Hydro also submitted that, given the separation of the issues in Sections 6 and 7 of Exhibit A-23 to the second phase, that it would support a separate argument and decision for these issues. (T6:1015-6).

The Terasen Utilities ("Terasen") submitted that the issues, argument and decisions should be severed into the two phases (T6:1016).

The JIESC strongly supported splitting off the Bella Bella issues (T6:1018).

The Heiltsuk submitted that an omnibus Zone II proceeding would not be appropriate until the NIA business plan is filed, that the October timing for the Special Contracts application was acceptable, and that, with care, two sets of Argument could be workable (T6:1019). The Heiltsuk also noted that while the relief sought by the Heiltsuk, if granted, would impact Zone I rates as would have been dealt with in Sections 1 – 5 of Exhibit A-23, that such impact should be negligible (T6:1019), and that it did not wish to impede the timely resolution of the principal matters of the RDA (T6:1020).

With respect to timing, the Heiltsuk agreed with the proposed September 3, 2007 commencement of the second phase (T6:21021), and further that consideration should be given to a third phase to deal with the Special Contracts (T6:1023-4).

The CEC supported the views of BC Hydro, Terasen, and the JIESC (T6:1024).

BCOAPO argued in favor of dealing with the issues under Sections 1-5 of Exhibit A-23 as one phase, those of Section 7 relating to Bella Bella as a second phase, and the broader issues relating to the NIA's as a third phase. It further argued that this third phase include proper notice to the parties affected, recognize the need to consult with the First Nations involved, and incorporate the these issues into the business plan for Zone II (T6:1030).

With respect to timing and separation of argument and decisions on the first two phases, BCOAPO supported the consensus view that was developing (T6:1032).

CCPC supported the separation into two phases and BC Hydro's submissions as to timing, but went on to register concerns as to scope of the "issues, motions and complaints" to be dealt with in the second phase (T6:1033-4).

The Heiltsuk indicated that the status of its complaint remained as pending (T6:1035).

BC Hydro raised two points in further submissions. Firstly, that the First Nations consultation issue as raised by BCOAPO was not clear cut (T6:1037), and secondly, that the uncertainty regarding the status of the Heiltsuk complaint or complaints was not helpful to the orderly conduct of the proceeding. BC Hydro submitted that either the Commission should reject the complaints based on their "informal" nature, or that the Heiltsuk should file them with the Commission in the "normal and formal process" (T6:1037-8).

BC Hydro also clarified that in its view, the application for the Special Contract rates for Zone II did not necessarily have to wait for the "omnibus" NIA/Zone II process it contemplated (T6:1039).

2.4.3.8 Formalization of the Heiltsuk Complaints – July 16, 2007

By way of letters to the Commission dated July 16, 2007, the Heiltsuk entered two complaints into the evidentiary record. The first particularized a complaint regarding CCPC pursuant to Commission Order No. G-30-2, (Exhibit C23-14) and the second particularized a complaint regarding CCPC pursuant to section 25 of the Utilities Commission Act (Exhibit C23-15).

2.4.3.9 Panel Decision in Respect of Timing of the Phased Hearing – July 16, 2007

Pursuant to its consideration of the submissions from the Parties, the Commission Panel decided to hear the Application in three phases as follows (T8:1331-1334):

- Phase I, covering the issues in Sections 1 through 5 of Exhibit A-23 will conclude on Friday July 20, BC Hydro will present its argument on August 3, Interveners will reply on August 17, and BC Hydro will make its reply argument on August 24. The Panel will issue its decision thereafter. A session for oral phase argument is to be scheduled by Commission Counsel for mid- September to be available should the Panel find it necessary.

- Phase II concerns the issues in Sections 6 and 7 of Exhibit A-23 and the two complaints of the Heiltsuk. It does not concern the BC Hydro Special Contract Rates or the Application BC Hydro may file following the completion of its NIA business strategy. CCPC can file its evidence, if any is elected to be filed, by July 24; on July 31, the report from the Parties as to the outcome of the negotiations to respond to the 33 questions and one IR of the Heiltsuk is due; IRs on CCPC's evidence, if any, are due on July 31, and

CCPC's responses to those IRs will be due on August 7. Parties are invited to comment on the issues in Sections 6 and 7 of Exhibit A-23, and the Panel will re-issue, if necessary, its revised issues list on August 16, 2007. The oral hearing will begin on September 4, and continue on September 5, 7, 8 and, if required, September 10. The Panel will hear submissions as to format and schedule of final argument, and make its determination accordingly in the week of September 4.

- Phase III will comprise BC Hydro's Special Contract Rates. BC Hydro is directed to file its Application with the Commission on or before October 1, 2007. Upon receipt of the Application the Commission will seek written submissions as to how it should be heard and will set out a Procedural Order pursuant to its consideration of those submissions.

2.4.3.10 CCCP Motion in Respect of Phase II of the Hearing – July 18, 2007

By letter to the Commission of July 17, 2007, entered as Exhibit C30-3, CCPC tabled a motion that the Phase II of the proceeding be adjourned to later in the Fall of 2007.

2.4.3.11 Submissions in Respect of the CCPC Motion – July 18, 2007

CCPC submitted that the Commission Panel's decision to hear the Heiltsuk complaints regarding CCPC as part of Phase II should be amended to defer that part of the hearing to late October or November in order that CCPC can properly defend itself (T9:1541). CCPC submitted that while it was prepared to proceed with the issues in Sections 6 and 7 of the Issues List, it could not have anticipated a process where a complaint filed against them would be heard in conjunction with a rate design hearing (T9:1542). Given that the status of the complaints was unclear until their formal filing on July 16, CCPC submitted that it had only that day become a party in respect of the complaint matters rather than a registered intervener, and that it required legal representation (T9:1543).

BC Hydro submitted that its overarching concern was that if the Commission proceeded to hear the complaint as part of Phase II as scheduled, that there is some risk of any Phase II decision getting unwound on the basis of procedural unfairness. BC Hydro submitted that "if the Panel in consultation with Commission Counsel concluded that that risk was significant," its preferred course of action was for the complaints and the hearing of the complaints to be severed from Phase II (T9:1545-6).

The Heiltsuk submitted that hearing the complaints as a separate process should be considered in light of the extent to which it would require a duplication of effort and evidence (T9:1547). Further, the Heiltsuk submitted that the primary consequence of the complaints is that they provide a basis upon which the Commission may go further [in terms of available relief] than originally contemplated by the rate design application on its face (T9:1548).

The Heiltsuk argued that CCPC and its industrial customer knew or ought to have known of the issues in Section 7 of Issues List, and the pending or potential complaints regarding CCPC from the inquiries and evidentiary record established in the proceeding (T9:1551-3), and that it was CCPC's choice not to intervene until the hearing began, and that that choice should not now result in a delay of the proceedings, and accordingly the motion should be denied (T9:1556-7).

In reply, CCPC declined to address the matter of delay raised by the Heiltsuk (T9:1557), but pointed out that it had relied on its understanding that the only issue in the proceeding that involved CCPC was the issue of whether their contract should be released, by way of an explanation for their lack of prior involvement in the proceeding (T9:1558).

2.4.3.12 Commission Panel Decision in Respect of the CCPC Motion – July 19, 2007

Following consideration of the submissions from the parties, the Commission Panel determined to sever the hearing of the Heiltsuk complaints from Phase II of the proceeding, on the basis of the concern that with the complaints only being formally filed with the Commission on July 16, 2007 CCPC has not received adequate notice in the circumstances (T10:1646).

Accordingly the complaints were referred to the Commission to establish its own process to hear them (T10:1647).

2.4.3.13 Commission Panel Decision in Respect of BC Hydro Special Rate for IPPs - July 19, 2007.

The Commission Panel considered BC Hydro's letter of July 6, 2007, Exhibit A2-3, concerning the Special Contract rate for three IPPs, and determined that the contracts should form part of Phase III of the proceeding (T10:1648).

2.4.3.14 Closure of the Record of Phase I of the Proceeding - July 19, 2007

On motion from Commission Counsel, subject to outstanding Intervener undertakings being filed by 4:00 p.m., July 27, 2007 and BC Hydro outstanding undertakings being filed by no later than the filing of its Final Argument on August 3, 2007 and the inclusion in the record of any letters received but not yet posted, the Commission Panel Chair declared the record closed as of 10:45 a.m..

2.4.3.15 Interim Commission Order No. G-111-07

In order to ensure that the Rate Schedules resulting from its Decision can be in place by April 1, 2008, the Commission Panel issued interim Order No. G-111-07 dated September 19, 2007.

2.5 Stakeholder Consultation

The Commission Panel notes that BC Hydro based its request for reconsideration and variance of Order No. G-96-06 of November 10, 2006, mentioned in Section 2.2.10 above, in part on enabling it to "… engage with stakeholders for approximately six weeks beginning in early January 2007 regarding the purpose and form of rate design applications, and to seek advice and input regarding issues and proposals to be addressed in the rate design application (Order No. G-148-06, paragraph I).

Commission Order No. G-148-06 issued November 28, 2006, among other things, directed BC Hydro to file the FACOS Study, the Rate Design Model and the list of issues, as set out in its application for reconsideration and variance, by December 11, 2006, and to file the RDA by March 15, 2007.

By letter to the Commission dated December 11, 2006, BC Hydro filed, by way of Appendices to that letter among other things, a list of issues to be the subject of BC Hydro's stakeholder engagement (Appendix A).

At that Appendix A, BC Hydro provided a list of issues to be discussed with stakeholders, the principal of which can be summarized as follows:

- Rate Rebalancing: "… should the rates of the five customer classes … be set to strictly match the allocated costs or … rebalanced to reflect an alternative allocation? …should there be a ceiling on any one-time adjustments as a result of any rebalancing….?"
- General Service >35kW: "The demand charge is … an inclining rate [structure] …. the energy charge is a declining block structure … Should there be changes to the ... rate so that the rate is simpler and sends a more appropriate conservation price signal?"
- E-Plus: "Should BCH eliminate the E-Plus rates? If so, how should the elimination … be implemented?"
- Distribution Extension Policy: "… a possible new methodology. BCH to engage with stakeholders about the ...Policy and the appropriate basis for calculation of the maximum BCH contribution." "BCH is considering increasing the threshold for the automatic refund [of 20% when the ... fee is $3,000 or less] from $3,000 to $10,000. Is this appropriate?"
- Other tariff changes: "BCH will be seeking stakeholder comment on various administrative changes to the tariff terms and conditions."

In the Application (Exhibit B-1, Appendix I - Stakeholder Engagement Summary), BC Hydro states that it consulted with its stakeholders by way of workshops, letters and web feedback, focus groups, surveys and one-on-one meetings. During January and February, BC Hydro interacted with 230 people from the Intervenor and "most impacted customer " groups, surveyed 720 E-Plus and 719 non-E-Plus residential customers, invited web or letter responses from all residential and commercial E-Plus customers, and held 20 meetings by invitation to workshop participants, and the top 10 impacted irrigation customers.

Section 4.2.1 of Appendix I to Exhibit B-1 summarizes the main themes arising from the workshops for the Large General Service rate class, and includes the following comments:

- "Many workshop participants felt that current energy and demand prices were too low to incent behavioral change and conservation,"
- "Some were very clear that their organization can only justify energy saving and demand management programs if these prices rise,"
- "Some … also felt that … the energy and demand blocks should be inclining and not flat; this would send a strong message around conservation," and
- "Workshop participants agreed in general that the current rate structure is at odds with energy conservation,"

albeit with the overriding caveat that time and assistance through more extensive Power Smart programs would be necessary to accommodate the restructured prices.

The nature and degree of BC Hydro's stakeholder engagement process in shaping and informing the RDA was explored in part in exchanges between the Panel Chair and JIESC Panel 2, representing Large General Service customers:

> THE CHAIRPERSON: …Now moving back to Exhibit B-68 which Mr. Manning presented you with this morning, if BC Hydro filed this application on March 15th [2007], am I right in assuming that really the first meaningful dialogue where it presented its options to you would be on January the 29th or had it done that before? We've got two meetings here. There's a FACOS workshop and a large GS workshop. Three scenarios are presented, two options, and it seems to me that before then--
>
> MR. JORDAN: A: I believe that's correct.
>
> THE CHAIRPERSON: Okay. So the previous 15 years that there had been silence from Hydro.
>
> MR. JORDAN: A: Well, other than getting our bills (T9:1475).
>
> THE CHAIRPERSON: No, I mean this Commission issued its instruction to Hydro to start flattening its rates back in '92, and we're now in 2007. So I take it that since '92, '3, '4 there hasn't been a great deal of discussion as to how it could do that.

> MR. JORDAN: A: Certainly. I’ve been involved in energy since 1999, and this process is the fist process I have been involved in dealing with the rate structure under 1211 (T9:1475-1476).

In its Final Argument, BC Hydro takes issue in part with this exchange between the Chair and this witness panel (T9: 1475, lines 7-19) on procedural grounds, and submits that no weight ought to be given to this evidence:

> “The form of question put to the witnesses was a “leading” question, that is, a question that presumes an answer. In court proceedings “leading” questions are only proper when asked of parties that are adverse in interest. Thus, counsel may not ask leading questions of their own witness because of an actual bias in favour of their witness; the advantage the questioner has in knowing what the answer might be; and the propensity of a witness to agree to propositions put to him or her by their own lawyer.
>
> While administrative tribunals such as the Commission are not bound by such strict rules, nevertheless, tribunal members must refrain from asking questions that could be perceived as unfair”(BC Hydro Argument, pp. 50-51).

The JIESC notes that BC Hydro suggests the question is unfair but does not dispute the facts summarized in the question or the answer provided. The JIESC submits that BC Hydro’s arguments are at best wrong and at worst could be construed as an attempt by BC Hydro to dissuade the Commission from using one of the most effective tools it has to assist in pursuing its mandate; direct questions to the parties appearing before it. The JIESC submits that the questions put by the Chair were clearly, properly and effectively put and contributed to all parties understanding of issues (JIESC Argument, pp. 19-20).

The Commission Panel determinations in this regard are found in Section 2.7.

The theme of the relevance of rate structure and pricing to strategic outcomes pervaded the proceeding, as manifested in the evidence of BCOAPO with respect to the role of marginal pricing (Exhibit C6-5), and that of Terasen with respect to the role of extension fees and connection charges in influencing residential demand growth (Exhibit C7-4). As well, the documentary record arising from the information requests contains numerous examples of rate design practices that send appropriate pricing signals in other jurisdictions, which have relevance to BC Hydro's Application.

These matters are also addressed in Section 2.7.

2.6 Hydro's Rate Design Principles and Foundational Aspects of the RDA

2.6.1 Rate Design Criteria

BC Hydro's proposed rate design criteria, in no particular order, are as follows:

- recovery of the revenue requirement;
- fair apportionment of costs among customers;
- price signals that encourage efficient use and discourage inefficient use;
- customer understanding and acceptance;
- practical and cost-effective to implement;
- rate stability;
- revenue stability; and
- avoidance of undue discrimination (Exhibit B-1, p. 27).

BC Hydro submits that these well-known and recognized rate design criteria are consistent with and satisfy the statutory test of "fair, just and not unduly discriminatory" (BC Hydro Argument, p. 15).

Furthermore, BC Hydro explains that given the length of time since its last RDA, the principal focus of the 2007 RDA is to ensure that BC Hydro's rates and Terms and Conditions are fair, efficient and simple and provides the following definitions for its three rate design objectives:

- **Fair** means that each customer bears a fair share of the costs caused by that customer, to the extent practicable.
- **Efficient** means that the rates and Terms and Conditions provide efficient price signals at the margin, including appropriate price signals to encourage energy conservation and load management, to the extent practicable.

- **Simple** means that the rates and Terms and Conditions are clear, transparent and cost-effective to implement (Exhibit B-1, p. 28).

In its Executive Summary of the Application, BC Hydro defines ‘Fair’ as meaning that each customer class bears a fair share of the costs caused by that class to the extent practicable. To clarify the hierarchy of its rate design criteria and objectives, BC Hydro confirms that appropriate price signals are one of the primary objectives of rate design, and not merely a subset of the efficiency objective (Exhibit B-26, p. 1).

BC Hydro’s 1991 and 2007 RDAs appear to share the same rate design criteria except for the criterion “rates should reflect all present and future private and social costs” which was not brought forward to the 2007 RDA. By way of explanation, BC Hydro states that this criterion, while not explicitly listed as one of the criteria, is encompassed within the criterion of “price signals that encourage efficient use and discourage inefficient use”, which itself is aligned with efficiency, as one of the three rate design objectives (Exhibit B-10, Commission Panel IR 1.3).

2.6.2 Foundational Aspects of the RDA

BC Hydro states that energy conservation is the first and foremost way to address its supply shortfall and that DSM needs to include appropriate rate design to help to meet this challenge. The fundamental policy question is whether the 2007 RDA, and the specific relief sought in it, is appropriate in light of what has transpired since 1991, given the 2007 Energy Plan and in view of the development of BC Hydro’s long-term rate strategy (Exhibit B-24, p. 1).

It is BC Hydro’s position that the 2007 RDA is the appropriate foundation for *future rate design proposals to implement the 2007 Energy Plan* , and that the RDA appropriately addresses the role of rates in influencing customers’ demand and energy consumption at this time (emphasis added). In support of its assertion BC Hydro refers to the Opening Joint Statement of its Panel (Exhibit B-26, p. 1). Conversely, BC Hydro suggests the Commission Panel ought to consider whether and to what extent acceptance of certain Intervenor proposals would undermine BC Hydro’s ability to bring forward new rate and resource acquisition proposals that are specifically intended to serve the 2007 Energy Plan (BC Hydro Argument, p. 4).

BC Hydro's view of the relationship between the RDA, the 2007 Energy Plan and the long-term rate strategy is summarized in the Opening Joint Statement of Ms. Sofield and Ms. Zacharias as follows:

> "… the proposed changes to BC Hydro's tariff are required to set a foundation upon which new rate structures to be developed through the long-term rate strategy can be used to affect the conservation goals directed by the 2007 Energy Plan. Further, the proposed changes are the most BC Hydro believes should be introduced at this time to avoid a material risk of being counter-productive. Conversely, BC Hydro believes that if certain issues it seeks resolution of are delayed, such as the re-balancing proposals and the re-structuring of the GS>35kW rate class, it will complicate moving forward with other rate initiatives" (Opening Statement, Exhibit B-24, pp. 3-4).

BC Hydro accepts it must persuade the Commission that the 2007 RDA, in light of the events that have transpired in the last 16 years, and in light of the 2007 Energy Plan, does in fact have the appropriate scope and that BC Hydro has proposed an appropriate suite of changes to its tariff. Furthermore, BC Hydro deems this to be a threshold policy issue because the Commission's determination with respect to it should inform the consideration it gives to the specific proposals both the Applicant and intervenors have put forward. Specifically, BC Hydro submits the Commission Panel ought to employ a test that acknowledges that BC Hydro, as an agent of the province, has a direct responsibility to implement government energy policy applicable to it. BC Hydro also submits that the Commission has no legal obligation to proactively implement government energy policy, except insofar as it may be expressed through legislation from time to time. (BC Hydro Argument, p. 3).

In light of the many changes since 1991, and the 2007 Energy Plan, BC Hydro notes it may seem remarkable that the 2007 RDA follows so closely the 1991 RDA and acknowledges that:

> "On its face, the 2007 RDA is an application that could have been filed many years ago" (BC Hydro Argument, p. 2).

Nevertheless, BC Hydro submits that although it must demonstrate that the 2007 RDA is of the appropriate scope:

> "… it does not follow that the Commission ought to simply substitute its judgment for BC Hydro's judgment where perhaps, more or less, could have been accomplished in this filing" (BC Hydro Argument, pp. 3-4).

2.6.3 Intervenor Submissions

BCOAPO argues that the evidence in the proceeding clearly indicates that the BC Hydro RDA does not set an appropriate foundation for future rate design proposals. The 2007 Energy Plan emphasizes the need for and value of conservation, recognizes the role of price in influencing customer behavior and envisages the development of new utility rate structures that encourage energy efficiency and conservation. In BCOAPO's submission the RDA does not in any significant way change the basis on which rates are established. To provide an appropriate foundation for implementing the 2007 Energy Plan, BCOAPO submits, the RDA should address how the impact of price should be recognized in rate design in order for it to be both fair and efficient (BCOAPO Argument, pp. 5-6).

The CEC points out that BC Hydro, by its own admission, paid no attention to conservation in setting residential rates. This fact, argues the CEC, does not support BC Hydro's contention that a "foundation" has been set for implementing the 2007 Energy Plan. Further, the CEC submits that clearly a cost based foundation with rate payers paying rates which do not contain cross-subsidies and which see all classes moving to paying as close to their actual costs under the FACOS is the appropriate "foundation" to go forward with for any long term rate strategy (CEC Argument, pp. 7, 13). The CEC concludes that the 2007 RDA does not set up an appropriate foundation for future rate design proposals and urges the Commission to aggressively implement rate design directions which are most likely to assist in meeting the objectives of the 2007 Energy Plan (T3:323-326).

The JIESC takes issue with BC Hydro's "threshold policy question" and argues that it is not a threshold question at all, nor is it helpful. Rather, the JIESC submits, it appears to be suggesting that the Commission decide whether, overall, BC Hydro has done an adequate job of preparing the 2007

RDA in the circumstances. The JIESC does not see that to be a useful question, as the Commission will be making determinations on all the individual aspects of the RDA. A general finding, such as the answer to the "threshold policy question" adds nothing (JIESC Argument, p. 3).

Terasen submits that "foundation" is defined as a solid ground or base on which a building rests. Foundations should be properly constructed, and should not be implemented with the intent that they be short-term in nature, or subject to reconstruction in the future. Terasen further states that at the end of the 2007 RDA proceeding, the Commission should order the implementation of a solid foundation for BC Hydro's rates and policies. Terasen believes that proposals they have put forward are important components of such a solid foundation (T3:309-310).

2.6.4 Frequency of Rate Design Applications

With regard to filing frequency, BC Hydro believes that comprehensive rate design applications need to be filed only every 3-4 years whereas applications for new optional rates or for the restructuring of existing rates, to support specific objectives such as conservation, will be filed on as required basis (Exhibit B-26, p. 1). A comprehensive RDA is expected to include a full Cost of Service Study update, address any associated rate rebalancing issues and review all BC Hydro's existing rates, and Terms and Conditions. On the other hand, a proposal of a specific new rate structure, designed to promote electricity efficiency and conservation, for instance, would be brought forward by BC Hydro as a stand-alone application with the relevant justification, studies and analytical back-up (Exhibit B-7, Terasen 2.1.2).

BC Hydro proposes that with certain exceptions the new rates take effect on April 1, 2008, which is expected to coincide with a general rate increase. This implementation date would serve to minimize the frequency of changes to customer rates and would directionally offset any bill reductions arising from the proposed rate rebalancing and restructuring. BC Hydro also points out that no party addressed the proposed implementation date for the new rates (BC Hydro Argument, p. 16).

In response to a Commission Panel inquiry, BC Hydro filed the following five-year regulatory filing outlook:

2008

- Winter: Residential Inclining Block
- Winter: Revenue Requirements F2009-F2011
- Spring: LTAP, including DSM Plan
- Spring/Summer: Smart Metering and Infrastructure (“SMI”)
- Fall: Zone II Rates

2009

- Additional conservation, peak reduction and load management rates for various customer classes.
- Report on first three years of Transmission Rate Schedule 1823/1825.

2010

- IEP/LTAP, including DSM Plan
- Rate Design Application

2011

- Revenue Requirements F2012-F2014
- Additional optional rates, including various structure/combinations to allow customer choice

2012

- LTAP, including DSM Plan
- Additional optional rates, including various structure/combinations to allow customer choice
- Refinements of default rates as required (Exhibit B-73).

BC Hydro submits that it and its Intervenors are entering a lengthy time period during which rates and issues directly related to rates will be debated, tested and ultimately adjudicated almost continuously. BC Hydro submits that the above full regulatory schedule and BC Hydro’s ability to achieve it are premised on the Commission’s acceptance of the threshold policy issue as proposed by BC Hydro, outlined in Section 2.6.2 (BC Hydro Argument, p. 9).

This can be contrasted with the impact of the 1996 to 2003 rate freeze as shown below.

In a Commission Panel IR BC Hydro was requested to advise what steps were taken to comply with the Commission Direction in the 1993 RRA Decision to pursue the integration of its Power Smart program with its rate design initiatives (Exhibit A-8). BC Hydro replied as follows:

> "Subsequent to the BCUC's decision regarding BC Hydro's 1994 RRA, BC Hydro and the BCUC became involved in litigation regarding the BCUC's jurisdiction over BC Hydro's resource planning. This was followed by a period of time during which BC Hydro's rates were legislatively frozen, and during which electricity industry de-regulation seemed to be radically changing the way in which energy utilities would be doing business. As with many other utilities, BC Hydro's early 1990's DSM initiatives lost their impetus." (Exhibit B-10, Panel IR 1.10.0)

2.7 Views of the Commission Panel on the Application and Determination

The Commission Panel is struck by the limited scope of the matters on which BC Hydro chose to engage with its stakeholders, and the minimal engagement with them in the process of developing the RDA, particularly since its last RDA was filed in 1991 – sixteen years ago. Given the amount of strategic and policy direction BC Hydro has received in the intervening years by way of direction from the Commission, and from its Shareholder, the Province, by way of the 2002 and 2007 Energy Plans, and in point of fact from the public pronouncements of its own executive, as highlighted in Sections 1 and 2 of this Decision, the Commission Panel finds BC Hydro's response disappointing.

BC Hydro's summary of the feedback it received on key issues at Section 4 of Appendix I to Exhibit B-1 clearly illustrates that it did not engage with its stakeholders to any meaningful degree on the fundamental role that rates, and their structure, can, and should, play in the achievement of the strategic agenda that has been set for it. With the exception of the albeit economically important GS>35kW Rate class, the feedback summary is essentially silent as to any references to debate and/or consensus around the role that rate structure can and should take in the achievement of the strategic objectives among all of the rate classes.

The Commission Panel also rejects the submissions of BC Hydro regarding the exchange between the Chair and the JIESC Panel, referenced in Section 2.5 above. In addition, the Commission Panel adopts the legal submissions at pages 19 line 16 to 20 line 17 of the JIESC Argument on the Commission Panel's ability to ask leading questions. The Commission Panel does not consider the questions unfair, and in this context relies on the complete evidentiary record in making its determinations.

The Commission Panel further notes the record that was available with examples of rate design practices that send appropriate pricing signals in other jurisdictions, which have relevance to BC Hydro's Application and of which BC Hydro was, or ought to have been, aware and could have taken into consideration in the 2007 RDA.

It is clear that Intervenors were not provided the opportunity to participate in meaningful dialogue as to the "issues and proposals to be addressed in the F2008 RDA" but rather were informed as to what BC Hydro had decided was going to be brought forward, and given limited opportunity to comment on a narrow range of issues and options of a non-strategic nature. Given that, the Intervenors have been left with no choice but to put their agendas for constructive change before this Commission Panel.

It is also abundantly clear that the Intervenors share the conclusion of BC Hydro's Shareholder and Executive that energy conservation plays a pivotal role in meeting the strategic objectives for BC Hydro and the Province, and that it is the only practical way to avoid dilution of the Heritage benefit with the ever increasing reliance on high marginal cost incremental supply. The Intervenors concerns are, in the Commission Panel's view, well founded, as, all else equal, the cost burden of the increased supply base will be borne by them.

The Commission Panel is troubled that BC Hydro's Application and its submissions in support thereof are not informed by those views. Rather, as acknowledged by BC Hydro in its Argument, on its face the 2007 RDA is an application that could have been filed many years ago (BC Hydro Argument, p. 2). The degree of importance given to this rate design process by BC Hydro is also reflected in the absence of any BC Hydro Executive members on the policy witness panel.

The Commission Panel contrasts the Stakeholder consultations BC Hydro conducted in order to inform the 2007 RDA, with those it conducted in support of its 2006 IEP/LTAP proceedings before this Commission. In finding that BC Hydro had appropriately engaged its stakeholders in those matters (IEP/LTAP Decision, May 11, 2007, p. 31) the Commission had before it a 286 page document entitled "First Nations and Stakeholder Report (ibid p. 27). In this proceeding, BC Hydro filed a 20 page "Stakeholder Engagement Summary" fully 40 percent of which is concerned with the relatively small and unique E-Plus customer subset.

The Commission Panel also observes that a sense of urgency appears to be missing in the 2007 RDA, which contradicts with the message to be found in the external communications of the BC Hydro Executive. BC Hydro's assertion that it has conducted significant rate design work over the past three years (Opening Statement, Exhibit B-24) is at odds with the absence of innovative proposals in the 2007 RDA.

In summary, the Commission Panel finds itself in a rather unusual position: BC Hydro asks it to approve only a foundation for future innovative rate designs, to defer development of the long-term rate strategy to BC Hydro and to only approve future filings piecemeal as they are submitted in due course. To resolve this the Commission Panel will make no ruling on the "foundational aspects" of the Application nor the "Threshold Policy" question as it does not believe that such findings would be of value in these circumstances. Instead, the Commission Panel will make its determinations on all the elements of the 2007 RDA having regard to the full body of evidence before it, and in accordance with the public interest.

With regard to rate design criteria, the Commission Panel finds that the 2007 RDA lacks some clarity regarding the interrelationship between the eight rate design criteria and the three principal rate design objectives, which makes assessment of the specific proposals somewhat more challenging. That notwithstanding, the Commission Panel finds that the basic rate design criteria themselves are appropriate and consistent with the statutory test of "fair, just and not unduly discriminatory" and accepts them as filed.

3.0 BC HYDRO'S COST OF SERVICE STUDY

This Section addresses BC Hydro's Fully Allocated Cost of Service Study ("FACOS"). It first summarizes the methodology used by BC Hydro, which is based on historical embedded cost pursuant to the Heritage Contract as compared to a marginal cost study, and then addresses marginal cost studies in rate setting. It then reviews the range of reasonableness proposed by BC Hydro for the revenue-to-cost ("R/C") ratios for the various customer classes. Lastly, it examines the methodology and assumptions used by BC Hydro in the performance of its FACOS.

3.1 Fully Allocated Cost of Service Study

The purpose of a FACOS is to allocate historical accounting costs to distinct customer classes in accordance with the costs incurred in serving each class. The total cost to be allocated is the utility's revenue requirement, which is the sum of operating and maintenance expense, depreciation and amortization, and financing charges, less miscellaneous revenues. In the case of BC Hydro, the total approved revenue requirement for F2008 is $ 2,836 million (Exhibit B-1, Appendix A, p.2). The revenue from each class under prevailing rates is divided by the costs allocated to that class in order to compute R/C ratios. BC Hydro states that the use of the revenue requirement net of the two percent rate rider revenue allows an easy comparison of the cost to serve by rate class with revenue by rate class, and results in a R/C ratio of 1.0 for total revenue and total cost (Exhibit B-1, p. 10).

The R/C ratios produced by the F2008 FACOS as provided in the Application at existing February 1, 2007 rates are shown below in Table 3-1:

Table 3-1
Revenue-to-Cost Ratios

Table 1 Revenue to Cost Ratios for February 2007 Rates

	F2008 Cost of Service $ million	F2008 Revenue $ million	Revenue - Cost $ million	Revenue to Cost Ratio %
February 1, 2007 Rates:				
Residential	1,179.7	1,109.9	-69.8	94.1%
Gen Serv < 35 kW	252.8	289.4	36.6	114.5%
Gen Serv > 35 kW	738.1	762.8	24.7	103.3%
Irrigation	6.6	4.3	-2.3	64.5%
Street Lights	22.6	23.3	0.7	103.0%
Transmission	636.4	646.6	10.2	101.6%
Total	**2,836.2**	**2,836.2**	**0.0**	**100.0%**

Source: Exhibit B-1, p. 29

In response to a Commission IR, BC Hydro filed Order No. 117/06 of the Manitoba Public Utilities Board. This document is a review of Manitoba Hydro's cost of service methodology and other matters. The Manitoba Board concluded that embedded cost studies continue to be the best test for fairness but specifically recognized that such studies are but one element of the overall rate setting process, which should also consider environmental costs, marginal costs and special circumstances (Exhibit B-7, BCUC 2.83.2, Attachment 1, pp. 7, 57).

3.2 Marginal Cost Studies in Rate Setting

BCOAPO witnesses Mr. Fussell and Dr. Shaffer advocate using a marginal cost study to allocate the revenue requirement instead of the FACOS (Exhibit C6-5). Since marginal costs are usually greater than embedded costs, and BC Hydro is only allowed to recover in rates its embedded costs (the revenue requirement), a method then must be chosen to reduce the revenue requirement calculated by the marginal cost study to the embedded cost level of the revenue requirement. BCOAPO advocates an Equal Percentage Marginal Cost ("EPMC") adjustment methodology in order that BC Hydro not over-collect its embedded cost revenue requirement. BCOAPO stated that this method proceeds by making equal percentage adjustments to the marginal costs so that the resulting total equals the total embedded cost revenue requirement (Exhibit C6-5, p. 5).

BCOAPO filed a study entitled "Long Run Incremental Cost – Update 2005/06" (Exhibit C6-12) which was prepared for BC Hydro by Energy and Environmental Economics Inc. and filed by BC Hydro as part of the 2006 IEP/LTAP Proceeding. BC Hydro did not present the study or any other investigation of marginal costs as part of its Application.

Dr. Shaffer testified that he is only aware of the EPMC approach being used in California and is not aware of it being used in any other jurisdictions in Canada or the United States (T3:399-400).

In response to an undertaking BC Hydro estimated the impact of setting rates based on a long run incremental cost ("LRIC) study and achieving a R/C ratio of 1.0, which resulted in the following:

Table 3-2
Rate Increases under LRIC

Rate Class	LRIC Revenue to Cost Ratio	Rate Increase to Achieve 100% R/C
Residential	108%	-7.4%
General Service < 35 kW	129%	-22.5%
General Service > 35 kW	99%	1.0%
Transmission	81%	23.5%

Source: Exhibit B-49, p. 3

Mr. Fussell testified that under the EPCM methodology that transmission class customers will see a large increase because they have very high load factors and are using proportionately more energy, and that the marginal cost of this energy is considerably higher than the embedded cost (T4:526), while Mr. Reimer, appearing for BC Hydro, testified that if incremental costs for generation are much higher than embedded costs then high load factor customers would pay higher costs in the future (T7:1101).

In response to an undertaking from BCOAPO BC Hydro states that the long run response to the implementation of LRIC-based EPMC rates under the assumptions specified by BCOAPO would reduce system wide energy usage by 287 GW.h or 0.5 percent, while the rebalancing proposals contained in the Application would increase energy usage by 29 GW.h or .05 percent (Exhibit B-57).

BCOAPO states that the EPMC "would provide an arguably more equitable allocation of the benefits of the Heritage Assets, offering all customer classes an equal percentage discount relative to what competitive market prices would be" (Exhibit C6-5, p. 6). Under cross-examination, Dr. Shaffer defined the benefit from the Heritage Contract as being the difference between the historic cost of the Heritage Resources and the marginal cost of new supply (T4:503-504). He further states that BC Hydro is implicitly allocating that benefit based on the difference between the fully allocated cost of service and the marginal costs, and that that allocation is a residual, not a conscious decision on BC Hydro's part (T3:412).

BC Hydro explains why it did not file a F2008 LRIC as part of the Application stating:

> "Marginal cost information can also be useful for rate restructuring purposes. However, it is not necessary to prepare a marginal cost-based cost of service study in order to use marginal cost information for rate restructuring purposes. For example, general knowledge of the magnitude of marginal energy costs in B.C. is sufficient information to conclude that the declining energy block structure on the GS > 35 kW rate is no longer appropriate.
>
> There was no requirement for, and BC Hydro did not rely on, a marginal cost based-cost of service study or marginal revenue to cost ratios in the 2007 RDA" (Exhibit B-3, BCUC 1.7.5).

BC Hydro states:

> "In BC Hydro's cost of service study, the costs of both Heritage and non-Heritage energy are allocated to the rate classes based on the energy consumption and peak demand of each rate class. As a result, each rate class receives a share of the benefits of the Heritage Resources based on the class' share of total consumption and peak demand" (BC Hydro Argument, p. 20).

BC Hydro does not provide a definition of the benefits of the Heritage Resources, but argues that under the EPMC approach the benefits of the Heritage Resources would be effectively allocated based on the total costs of serving each rate class. BC Hydro submits that it is inappropriate to allocate the benefits of the Heritage Resources based on the total costs of serving each rate class since the Heritage Resources only relate to the generation function. In BC Hydro's view it is more appropriate to allocate the benefits of the Heritage Resources based on the energy consumed by each rate class, rather than based on the total costs of serving each rate class (BC Hydro Argument, pp. 20-21). BC Hydro states that the Heritage Contract scheme established that BC Hydro's rates are to be determined on a cost of service (historical cost) basis, and references Schedule B of the Terms of Reference for the Heritage Contract Report, (which listed BC Hydro's then existing rate schedules) as providing as a corollary principle that new customers should also benefit from the low cost Heritage Resources. BC Hydro further states that HC2 left the Commission with significant discretion to design rates for all customers and allocate the benefits of the Heritage Resources between customer classes (Exhibit B-3, Heiltsuk 1.7.1).

Corix agrees that embedded costs studies are the appropriate way to determine interclass revenue requirements and summarizes its position as follows:

> Corix contends that the Rate Design Application is primarily about "splitting the tab" in a fair, just and reasonable method. To the extent that the various customer classes have shared in the supply of electricity and related services, the Commission must now adjudicate on how this bill is to be divided amongst those at the table.
>
> It would seem relevant to split the tab on the basis of costs incurred and not at how each customer class fared at the margin. That would be more an "intra-class" refinement (e.g. increasing trailing block) and not a basis for "inter-class" rate redistribution for the embedded costs of electricity.
>
> While there is merit in considering marginal rates to induce the correct consumer response, as mentioned previously, there has not been a fulsome discussion of that in this proceeding and the Commission should not be swayed to allocate embedded costs in this fashion or to delay correcting present imbalances in the fully allocated costs of B.C. Hydro amongst its various customer classes (Corix Argument, p. 7).

CEC submits that the EPMC approach is inconsistent with the Heritage Contract directions from the Province and would result in a re-allocation of Heritage benefits and would result in a re-allocation of the benefits in a manner not supported by the legislation (CEC Argument, p. 9).

JIESC submits that even though the EPMC method has been used in California since 1976, it has not been adopted in any other jurisdiction in North America and casts doubt about its current status in that state (JIESC Argument, p. 25).

The B.C. Sustainable Energy Association, Sierra Club of Canada (B.C. Chapter) and the Peace Valley Environment Association ("BCSEA") commends BCOAPO for bringing forward evidence on the use of a marginal cost study but is not convinced that the effort to implement BCOAPO's EPMC methodology would be warranted in relation to the actual gains in conservation and efficiency (BCSEA Argument, p. 4).

In reply, BC Hydro submits that BCOAPO's proposition is not supported by the evidence and that it is unclear what purpose would be served if the Commission were persuaded to require a marginal cost based allocation study proposed by BCOAPO and rejected the 2007 RDA in its entirety (BC Hydro Reply, p.4).

Commission Determination

The Commission Panel notes that there has been no widespread adoption of the use of LRIC studies to determine each of the classes' responsibility for the revenue requirement and agrees with the Applicant, and most Intervenors, that given the present circumstances, the FACOS using embedded costs is the appropriate tool with which to assign cost responsibility.

3.3 Range of Reasonableness and its Relationship to the FACOS

BC Hydro states that the principal focus of the Application is to ensure that its rates and Terms and Conditions are fair, efficient and simple and that 'Fair' means that each customer class bears a fair share of the costs caused by that class, to the extent practicable. BC Hydro considers it reasonable that each customer class should be responsible for the recovery of costs to serve them, while acknowledging that assessing the costs of service requires many assumptions and estimations of data. In this context it is BC Hydro's view that customer classes' revenue-to-cost ratios should fall within a reasonableness range of 90 percent to 110 percent (Exhibit B-1, p. 1).

BC Hydro states that this range takes into account and recognizes the many assumptions that are necessary in the development of a cost of service study, which is not an exact allocation of costs. Considering a range of reasonableness for R/C ratios is common utility regulatory practice (Exhibit B-1, p. 29). BC Hydro testified that if a class R/C ratio falls within that range of reasonableness then its full cost of service is being recovered, and no further adjustment or rebalancing of rates is required (T4:637).

3.3.1 Load Research

A key input to the cost of service analysis is data on energy and capacity use for each of the customer classes on (at least) an hourly basis.

BC Hydro states that it relies on load research data to estimate the load shapes for the residential, small general service and large general service rate classes. Its load research samples have a design accuracy of +/- 10 percent with a confidence interval of 90 percent at the time of the class peaks but the accuracy of the load research samples may be less at the times of the monthly system peaks. The combination of the hourly load research data and the hourly metered data for the transmission customers is used to determine the contribution of each rate class to each monthly system coincident peak demand.

Further, BC Hydro states that the hourly load research and metered data are not normalized for weather or other factors such as economic conditions, and that the small size of the transmission rate class makes the transmission load shape susceptible to the actions (such as maintenance scheduling) of a small number of customers. The historical monthly share for each rate class (averaged over two years) is assumed to apply unchanged to the forecast year F2008. No adjustments were made by BC Hydro for differences in the forecast load growth of the various rate classes or for any other factors (Exhibit B-7, BCUC 2.87.1).

Since most customer classes do not have interval metering, BC Hydro for several years has undertaken a load research program. BC Hydro produced the following table which provides the accuracy of its load research program:

Table 3-3

	GS > 35 kW	GS < 35 kW	Residential
Accuracy at Time of Class Peak	4%	10%	7%
Targeted Accuracy	10%	10%	10%

Source: Exhibit B-7, BCUC 2.114.1

BC Hydro testified that it has interval meters for the transmission class and does not need a load research program for this class, and that since the interval metering reflects each customer's specific load profile, the confidence level is close to 100 percent (T7:1145).

BC Hydro further submits that its load research samples meet industry standards and that in its view the costs of improving the accuracy of the load shape would outweigh the benefits of further narrowing the range of reasonableness (BC Hydro Argument, p. 38). BC Hydro testified that it has not prepared a cost/benefit analysis to verify this belief (T7:1144).

BC Hydro observes that in this Application it had narrowed its range of reasonableness from the 85 percent to 115 percent which was proposed and accepted by the Commission in the 1991 RDA, to the narrower range of 90 to 100 percent, reflecting improvements in its load shape data (Exhibit B-7, BCUC 2.87.1).

The Commission Panel examined BC Hydro as to the symmetry of the error inherent in its load research:

> COMMISSIONER MILBOURNE: First I had a couple of questions on revenue-to-cost ratios. Would you agree that there's no particular body of evidence before us that the revenue-to-cost ratios that arise from your approach have any different level of percentage uncertainty or potential variability about the value you've given for each of the rate classes? ... So I'm asking you whether, if you've got a number that say it's 92, is it 92 plus or minus something, Class A different from the '98 plus or minus something for Class B? In other words, is the plus minus something the same for both classes? In other words, is the plus minus something the same for both classes?

> MS. SOFIELD: A: I would agree that there’s no evidence …
>
> COMMISSIONER MILBOURNE: Thank you.
>
> MS. SOFIELD: A.--that supports any quantification of that.
>
> COMMISSIONER MILBOURNE: NOW, the second part of this question is, would you further agree that there's no evidence that the pluses or minuses are not symmetrical about the given value? In other words, Class A isn't kind of minus 5 plus 10, and Class B kind of minus 10 plus 5. So whatever the plus/minus is, it's not unsymmetrical about the given value for the different classes.
>
> MS. SOFIELD: A: I think we would agree with that, yes.” (T7:1187-88)

BC Hydro states that as illustrated by the responses to Terasen Information Requests 2.5.1 through 2.5.4 (Exhibit B-7) changes in the assumptions inherent in a FACOS study can have material impacts on the resulting R/C ratios. BC Hydro submits that examples of the many assumptions in a FACOS include:

- the selection of hours to use to allocate demand related costs (e.g. 1CP vs. 12 CP)
- the selection of costs to classify as demand-related (e.g. the use of 50/50 demand/energy for hydro fixed costs and the use of 75/25 demand/customer for distribution fixed costs) (BC Hydro Argument, pp. 37-38).

BC Hydro states that it has not undertaken a comprehensive survey of other regulatory jurisdictions in North America regarding the range of reasonableness, but it has determined that Alberta, Saskatchewan, Manitoba, New Brunswick and Nova Scotia use a range of reasonableness of 95 percent - 105 percent, while Ontario is shown as the only province with a 90 percent - 110 percent range (Exhibit B-3, JIESC 1.7.1).

3.3.2 Intervenor Positions

The JIESC disagrees with BC Hydro’s position and submits that once the key allocation methodologies for capacity and generation have been established, and reasonable, appropriate allocations are used for other costs, the variation in cost of service and R/C results would be expected to vary by less than five percent. The JIESC further submits that in conjunction with the known system demand and demand metering of large commercial and industrial customers, the accuracy of the relatively sophisticated load research analysis should be reasonable and acceptable within the overall range of reasonableness of 95 percent to 105 percent (Exhibit C18-7, p. 9). The JIESC states that BC Hydro has confirmed that there is no systematic directional bias in the allocation factors and that therefore there is no reason to stop adjusting rates as soon as a class is within the range of reasonableness (JIESC Argument, p. 13). The fact that a class is within the range of reasonableness should only be an indicator of the urgency of the need to make a rate adjustment, not an elimination of the need to make an adjustment (JIESC Argument, p. 14).

The JIESC does not accept BC Hydro's position that once a customer class's revenue-to-cost ratio is somewhere between 90 and 110 percent, that class has reached the ultimate target and is paying its costs. The ultimate consequence of BC Hydro's approach is that if rate design shifts are only made to move a customer within the boundaries, those that start high will stay high and those that start out low will stay low. When the range is wide, as proposed by BC Hydro, this approach is even more unfair (JIESC Argument, p. 13).

The CEC agrees with JIESC regarding the symmetrical impact of the FACOS assumptions on R/C ratios (CEC Argument, pp. 15-16). The CEC believes that by setting customer rates close to unity, it is less likely that customer classes will move outside acceptable boundaries over a short period of time, thereby reducing the need for frequent rate design applications and the related costs of such processes (T3:325), and that moving all revenue-to-cost ratios as close as possible to unity is the most fair approach (CEC Argument, p. 71). The CEC suggests that the Commission distinguish between the rate setting policy decision and the policy decision for triggering the next rate review. In setting rates, the CEC believes, the Commission ought to move the rates towards an R/C ratio of 1 (unity) over appropriate phase in periods. Once that decision is made the range of reasonableness can be used as one of the parameters to determine if R/C ratios have moved sufficiently to warrant another rebalancing. Once another review is conducted before the Commission, then rates again can be moved toward unity over a phase- in period as required (CEC Argument, p. 27).

Corix submits that the Commission should, at a minimum, move to a 95 to 105 percent range for assessing whether rate shifts are required and that ideally, customer classes should be moved to a R/C ratio of 1 to ensure that rates are as balanced as reasonably possible, given the accuracy of the information available (Corix Argument, p. 4).

In reply, BC Hydro submits that adjusting R/C ratios over time as they varied from unity would be unduly mechanistic and would render the other rate design criteria virtually useless and continues to advise the Commission to reject proposals that would require rates to be set to maintain unity R/C ratios (BC Hydro Reply, p. 7).

3.3.3 Bill Impact and Mitigation

BC Hydro submits that although rate rebalancing and restructuring can be viewed as independent activities, they must be considered together for assessing customer bill impacts. With regard to acceptable level of bill impact, BC Hydro has endeavored to limit the combined annual impact of rebalancing and restructuring on any individual customer bill to no more than ten percent, exclusive of any changes arising from general increases. This is not a rule that is intended to be binding in every circumstance. For instance, BC Hydro believes that it is acceptable for bill impacts to exceed 10 percent per annum where the absolute dollar value of the increase is very small (BC Hydro Argument, p. 17).

BCOAPO submits that the use of ten percent as a threshold for “rate shock” should not be limited to the combined effect of rate rebalancing and restructuring, but also include the impact of any general rate increase. From a customer’s perspective, the impact of higher bills is the same regardless of whether they are the result of a general rate increase, rate rebalancing or a change in rate structure. All three sources of bill impact must be included in the definition of rate shock (BCOAPO Argument, p.23).

In reply, BC Hydro submits that aside from the practical difficulties in doing so when future revenue requirement increases are unknown, its proposed rate changes result in bill impacts that are less than ten percent per year (BC Hydro Reply, p.5).

In terms of the right balance between the length of phase-in periods for rate rebalancing and rate restructuring to avoid rate shocks, and sending better price signals, BC Hydro gives its GS>35kW proposal as an example. Even with a three-year phase-in of the restructuring, 955 customers would experience annual bill increases of more than ten percent. Notwithstanding that, BC Hydro considers that the proposed three-year phase-in represents an appropriate balance between the desire to provide better price signals and the desire to mitigate the impact on adversely affected customers (Exhibit B-26, p. 5, Exhibit B-3, BCOAPO IR 1.5.1).

Furthermore, BC Hydro does not consider re-distribution of revenues to customers within a rate class objectionable. It submits that re-distribution of revenues is an unavoidable consequence of rate re-structuring (Exhibit B-26, p. 5).

In response to a question by the CEC, whether past R/C ratios should be a consideration in rebalancing of rates, BC Hydro submits that rates approved by the Commission are by law just, reasonable and not unduly discriminatory. Consequently, there can be no past inequities that must somehow be redressed in future rate rebalancing. BC Hydro therefore submits that the period of time and degree to which a rate class may have had a R/C ratio greater than 100 percent should not be a consideration in the proposed rebalancing of rates (BC Hydro Argument, p. 42).

Methods of mitigation considered by BC Hydro to lessen the impact on customers adversely affected include the following:

- extended periods over which the changes would be implemented;
- advance notice
- raising the awareness of opportunities to participate in Power Smart programs (Exhibit B-3, ESVI IR 1.10.1).

Commission Determination

The Commission Panel notes the wide spread practice of setting the range of reasonableness at 95 percent - 105 percent in other jurisdictions. Furthermore, the Commission Panel is persuaded by the JIESC position that once the key allocation methodologies have been properly established, the variation in cost of service and R/C results would be expected to be less than five percent and notes the evidence that there has been no systematic bias in allocation. The Commission Panel also agrees that in conjunction with the known system demand and demand metering of large commercial and industrial customers, the accuracy of the relatively sophisticated load research analysis should be acceptable within the overall range of reasonableness of 95 percent - 105 percent.

Accordingly, the Commission Panel finds that the range of reasonableness of 95 percent - 105 percent is the correct range for the purpose of future rebalancing in the circumstances of BC Hydro. **BC Hydro's proposed range of reasonableness of 90 percent to 110 percent is denied.**

The Commission Panel is further persuaded by the Intervenors' argument that under BC Hydro's approach of not making adjustments within its 90 percent - 110 percent band, those classes that start high will remain high and vice versa. Accordingly, the Commission Panel finds that the appropriate target for R/C ratios in each class is unity or one in this RDA, and that future rebalancing should only be required when a customer class falls outside of the range of reasonableness.

BC Hydro is directed to adjust its rates in equal percentage amounts over the next three years so as to achieve R/C ratios of unity for each class after adjustments to the FACOS as described elsewhere in this Section and to file Rate Schedules for all classes for the first phase of the three year phase-in with rates effective April 1, 2008 with the Commission, together with supporting documentation, within 60 days of the date of Order No. G-111-07.

BC Hydro is directed to undertake FACOS studies on an annual basis within 90 days of its fiscal year end in order to calculate actual R/C ratios and determine the need for future rate rebalancing applications in regard to the 95 percent to 105 percent range of reasonableness and submit the findings to the Commission.

3.4 Methodology and Assumptions for BC Hydro's FACOS

This Section reviews the relevant methodology and assumptions BC Hydro used in carrying out its FACOS. In particular, the method used to allocate demand related generation and transmission costs, demand/customer split for distribution system cost, hydro plant cost allocation, and other miscellaneous assumptions are addressed.

3.4.1 Generation Demand and Transmission Demand Allocator

BC Hydro proposes to allocate all transmission costs and demand related generation costs based on the twelve coincident peak method ("12 CP"). This proposal was challenged by both JIESC and Terasen who submitted evidence on this topic. JIESC provided expert evidence from Mr. Joe N. Linxwiler who recommends that the 4 CP method (November through February) would be the most reasonable demand allocator for generation and transmission costs (Exhibit C18-8, pp. 3-4, 20). Terasen is also of the view that a winter peak demand allocator would be more appropriate for transmission and generation. Terasen provided evidence from Ms. Tabone and Ms. Falcon of EES Consulting ("EES") which specifically suggests the 3 CP allocation method (November through January) (Exhibit C7-4, EES Evidence, p. 28). These alternative proposals are discussed below.

BC Hydro states in response to an IR that the choice of an allocator is, to a significant degree, a matter of judgment. BC Hydro submits that a 1 CP allocation of generation costs was common in early cost of service studies, but, as load became flatter, allocation factors were modified to take into account more hours such as with 4 CP or 12 CP. BC Hydro also states that in a market based jurisdiction generation demand allocation is not necessary as the market considers conditions every hour; the implicit method effectively becoming an 8,760 CP allocator (the number of hours in a non-leap year), and that BC Hydro's system is built to ensure there is sufficient generation capacity to meet the demands of electricity consumers. Since generation facilities in B.C. are planned to reliably meet the coincident peak and unreliability occurs for more than simply one hour per year, this indicates that demand related generation costs are appropriately classified on the basis of 12 CP (Exhibit B-3, BCUC 1.18.2).

Regarding the allocation of transmission demand-related costs, BC Hydro stated:

> "BCTC is responsible for maintaining the reliability of the transmission system. The transmission system is built to ensure there is sufficient transmission capacity to deliver electric energy across the province throughout the year. BCTC has not proposed any changes to the classification of transmission demand related costs since the 1993/94 Cost of Service Study when peak demand was defined as the loads of each class during each of the 12 monthly coincident peaks in the test year" (Exhibit B-3, BCUC 1.18.2).

A number of relevant matters were introduced by way of Intervenor Evidence and cross-examination of both BC Hydro and Intervenor Panels. These are the importance of the winter peak, transmission congestion, impact of temperature, and tests used by other jurisdictions in selecting a demand allocator.

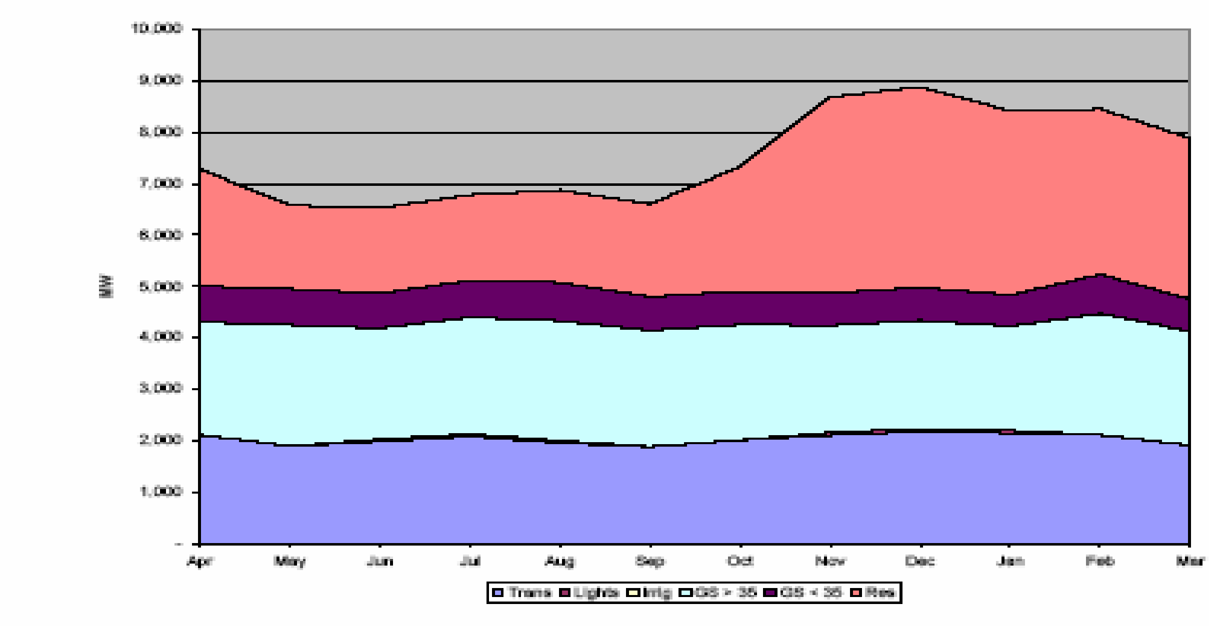
3.4.1.1 Importance of the Winter Peak in BC Hydro System

BC Hydro testified that its Conservation Research Initiative ("CRI") pilot used an on-peak period that was the four months from November through February (T4:630). It further testified that the demand ratchet clause for Rate Schedule 1823 takes effect for the same period and that the demand ratchet sends a price signal and that the signal is to avoid setting a peak during that period (T5:823). As noted by CEC, BC Hydro acknowledges that the capacity view of the load/resource balance, as presented in its IEP/LTAP, includes the integrated system peak load, which falls in the winter, and for which BC Hydro plans its resources (Exhibit B-45; CEC Argument, p. 53). BC Hydro also states that the Interior Lower Mainland ("ILM") Reinforcement Project is required to meet the winter peak and has confirmed that with BCTC (T5:748). BC Hydro's minimum monthly billing charges for its general service customers are based on an on-peak period from November through March (Exhibit B-1 Appendix D, p. 7).

Terasen submits that there can be no doubt that BC Hydro's system peak will occur between November and February, and that the residential class largely drives the seasonal variability of BC Hydro's peak demand and contributes significantly to the high winter peak, and references a BC

Hydro graph depicting load shape for 2007 which is reproduced below (Terasen Argument, p. 17):

Table 3-4
Contribution to Monthly Peak by Class



Source: Exhibit B-3, Terasen 1.9.1

Under cross examination by counsel for BC Hydro, Mr. Linxwiler was presented Exhibit B-59, which included a loss of load probability ("LOLP") table. In describing the allocation of production plant, the National Association of Regulatory Utilities Commissioners' ("NARUC") Electric Utility Cost Allocation manual states that if a utility bases its expansion planning on reliability criteria such as LOLP, that have significant values in a number of hours other than the single peak hour, it may be appropriate to include demand in hours other than the peak in the basis for allocating demand related production costs (Exhibit B-59, p. 39). BC Hydro states that generation capacity is planned using a loss of load analysis to maintain a LOLP of less than or equal to one day in ten years (Exhibit B-7-1 CEC 2.8.2). Mr. Linxwiler testified that examining the table tells him a 4 CP method is appropriate since no maintenance is scheduled during the months of November through February, because those are critical months. He also stated that maintenance is scheduled in the remaining months, with no adverse affect on the remaining reserve margin (T8:1370).

3.4.1.2 Congestion in the Southern Interior and Other Transmission Matters

BC Hydro stated that the existence of congestion in the summer time in the south interior of the province was identified in BCTC's South Interior Bulk System Development Plan and that this congestion "is entirely related to serving domestic load" (Exhibit B-3, Terasen 1.12.2), and that for the months of July and August 12-13 percent of total system load on an energy or capacity basis was for supply to the Southern Interior (Exhibit B-3, Terasen 1.12.1).

BC Hydro also stated that "Delivering hydro generation capability during the spring freshet can drive transmission costs" (Exhibit B7-1, CEC 2.8.2) and provided an extract example from the BCTC Capital Plan Appendix C, Section 5.2 that stated that the power flow on the Southern Interior cut-planes is heavier in the June to July (summer) period with the peak flows usually corresponding to the spring freshet period. The same document provides additional description:

> The forecasted transfer demand is the hourly average peak value at the cut-plane in summer. It may occur at light load condition during freshet season. The summer transfer demands at the two cut-planes are much higher than those in the winter in the South Interior. Therefore, these summer transfer demands are used in planning studies (Exhibit B-7-1, CEC 2.8.2, Attachment 1, p. 42 of 172).

When asked by counsel for JIESC if they had attempted to quantify monthly stress, BC Hydro replied:

> MR. REIMER: A: Oh, we have not quantified overall, I think, the impact of cost to alleviate stress by months. Now, I mean, that could be done. It would be a fairly large undertaking and would require the assistance of BCTC to determine the rationale for every capital project. Is it built to alleviate stress that's associated with load? Is it associated with generation? Or a combination of those two factors? And is there a seasonal component? So that could be done, and that would be a fairly large undertaking (T5:809).

BC Hydro's LRIC study concluded that changes in demand during most hours of the year would have no impact on bulk transmission costs and that bulk transmission projects are for the most part driven by peak demands, but that the bulk transmission costs calculated in the LRIC only apply to changes in end user demand levels and do not apply to changes in generation supply (Exhibit C6-12, BCUC 2.393.1, pp. 10, 13)

BC Hydro states that for the purposes of a cost of service study that "… transmission (along with remote generation) can be considered a substitute for local generation" (Exhibit B-7, CEC 2.8.2). The matter of transmission lines connected to remote generation was considered in both the Decision related to the BC Hydro Wholesale Transmission Services Application dated June 25, 1996 ("1996 WTS Decision") and the Decision related to the BC Hydro June 1997 Wholesale Transmission Services Application ("1998 WTS Decision").

The 1996 WTS Decision described BC Hydro's position on the generation related transmission assets ("GRTAs") in part as:

> More specifically, generation-related transmission facilities were defined to include: (1) those transmission lines which tie remote generation located in the North and South Interior regions of the province to the rest of the system; (2) the portion of generation substation assets related to transformation equipment which steps up voltage from the level at which it is generated to the bulk transmission voltage used to carry power towards the load; and (3) some general assets (1996 WTS Decision, p. 6).

At that time the Commission did not feel that there was sufficient evidence to accept BC Hydro's proposed treatment of GRTAs and directed BC Hydro to file new WTS rates based on a study precisely identifying the transmission revenue requirement and in particular it should reflect the relative benefits which GRTAs provide to the generation and transmission functions (1996 WTS Decision, p. 16).

BC Hydro provided the requested study as part of the subsequent 1997 WTS application. In the 1998 Decision the Commission agreed that the assets selected by BC Hydro were the GRTAs at issue (these assets included transmission lines and substations connected to the Kootenay Canal and Seven Mile generating stations located in the Southern Interior), and directed that the GRTAs be functionalized 100 percent to generation (1998 WTS Decision, pp. 16-19). BC Hydro confirmed that this treatment continues in this Application and FACOS for those assets (Exhibit B-1, BCUC

1.11.1). The Application shows that the GRTAs are allocated 53.31 percent to energy and 46.69 percent to demand on a 12 CP basis (Exhibit B-1, Appendix A, Schedule 2.0).

3.4.1.3 Impact of Temperature

BC Hydro states that the load carrying capability of the transmission system may be diminished with higher ambient temperature and provided an example where an overhead conductor had a rating of 900 amperes at zero degrees Celsius, and a rating of 730 amperes at thirty degrees Celsius, a difference of 23 percent (Exhibit B-3, Terasen 1.11.1). BC Hydro further states that thermal constraints occur in the summer that drive the need for expansion of the transmission system and provided as a reference the BCTC F2008-2017 Capital Plan at Appendix C, without further detail. Appendix C to this document is the "South Interior Bulk System Development Plan Report" which comprises some 200 pages (Exhibit B-7-1, CEC 2.8.2, Attachment 1).

Mr. Linxwiler testified that he considered thermal constraints on the transmission system capability but that in his opinion the impact was "negligible" (T8:1367). This opinion was shared by the experts retained by Terasen who agreed that the impact of temperature was insignificant and would be in the range of five percent (T9:1618).

3.4.1.4 FERC and OEB Tests

Both the expert evidence of Mr. Linxwiler and that of Ms. Tabone and Ms. Falcon discussed tests used by the Federal Energy Regulatory Commission ("FERC") and their use in the selection of the appropriate transmission demand allocator. The FERC tests are basically measures of dispersion of the monthly system peaks. EES also considered a test used by the Ontario Energy Board ("OEB") which is similar to those employed by FERC.

Mr. Linxwiler's Evidence

Mr. Linxwiler calculated the four FERC metrics based on BC Hydro monthly peak data for each year from F2001 through F2007. Two of the tests are described as being "Basic Ratio Tests for

12CP Method" (Exhibit C18-8, Attachment JNL-2, pp. 5-8). In calculating these two tests the values are also calculated excluding 2003 which he states to be an anomaly since it was particularly mild (Exhibit C18-8, pp. 16-19). Mr. Linxwiler states that his assertion that 2003 was particularly mild was not based on an analysis of temperature data or a consideration of factors such as strikes at major customers, but solely on observing the data (T8:1378).

Mr. Linxwiler also points out that in some cases FERC has found that ratios above 70-71 percent support the 12CP method and that when 2003 is not excluded the value is slightly above this range, but that when 2003 is excluded the 12 CP allocation method is even less supported by those metrics (Exhibit C18-8, pp. 15-16).

Mr. Linxwiler addressed the application of these tests in FERC jurisdictions and in British Columbia in an exchange with counsel for BCOAPO:

> MR. LINXWILER: A: No, I would say that based on that test alone, the 12 CP is not ruled out. I think one of the things you have to realize about the cases in which that ratio has been applied and the other ratios for utilities in the United States, regulated by FERC, is that most of them have predominant winter and summer peaks. I tried to address that in my testimony. That they are two-humped camels, by and large.
>
> MS. WORTH: Q: And we're a one-hump camel.
>
> MR. LINXWILER: A: That's right. And in cases where you have a single predominant seasonal peak, I think that you're likely to get a different range of ratios – not likely, you usually do – and that it's not particularly meaningful to compare that to most utilities -- or the values of the ratios for most utilities that would include -- or the vast majority of which would include summer and winter peak systems. And I think if you sort of look at most of FERC's practice, it does include winter and summer peaking utilities. So when you read what the Commission has done with these particular ratios, in most cases I think you have to understand that that's by and large for winter and summer peaking utilities. And there have been fewer single season peaking utilities, some of which I have had the occasion to deal with, and in those cases you do find on some of these tests higher ratios, particularly on this one. (T8:1321-22)

The EES Evidence

EES recommended the use of a 3 CP allocator based on an analysis of the FERC and OEB metrics. Its filed evidence and recommendation was based on the use of data for only 2007 as confirmed in a discussion with counsel for BCOAPO (T9:1519):

BC Hydro states that efforts to subjectively select one year of data or to ignore it or to suggest that there is a trend evident in seven years of non-weather-normalized data should be dismissed by the Commission and therefore, even absent the supply side conditions, the evidence on load shape alone supports the continued use of 12 CP method (BC Hydro Reply, p. 15).

Mr. Reimer's Evidence

Mr. Reimer states he did not calculate the FERC or OEB ratios prior to filing his evidence on behalf of BC Hydro. He states that he believes the ratios calculated by EES (T5:818) support the 12 CP allocator, but states his concern with relying on this approach:

> MR. REIMER: A: I did not perform them prior to the determination that 12 CP was appropriate. We have certainly looked at them since. And I find that one of the issues with the FERC and the OEB tests are that they only consider the load, like the demand. And really, in the determination of what type of classification is appropriate, you need to look at both the supply as well as the demand. Both factors have to be taken into account. You cannot look at just one factor and make a proper determination of the appropriate classification (T5:743).

3.4.1.5 Intervenor Submissions

BCOAPO submits that the 12 CP method proposed by BC Hydro for allocating demand-related generation and transmission costs is appropriate. However, BCOAPO notes its previous recommendation regarding the need to review the classification of generation costs and the fact that more recent methods of classifying generation costs, such as allocation of generation costs based on the marginal costs of supply in various time periods, can also give rise to different allocation methods (BCOAPO Argument, p. 17; T5:676).

The CEC is of the view that there is little doubt that the winter system peaks are significant and are being driven by the residential heating load. The CEC argues the fact that the peaks become more pronounced in the colder winters (2007) than in the milder winters (2003) is significant evidence of this and is also a significant system design requirement at this time (CEC Argument, p. 55).

The CEC acknowledges that the off-peak supply issues BC Hydro has raised in support of the 12 CP method are relevant but are very unlikely of equal weight with the winter peak requirements. This is, argues the CEC, because there are simply too many large cost portions of the electric system that are not affected by these issues. The CEC is of the view that these issues do not block the supporting evidence for moving away from a 12 CP but do raise an issue as to whether it might be appropriate to do more analysis to support some middle ground (CEC Argument, p. 61).

In summary, the CEC submits that BC Hydro has not met the burden of proof that the 12 CP method with equal monthly weighting is appropriate. The CEC is of the view that a 4 CP method is more appropriate and that the significance of the rate change implications and the off-peak supply issues BC Hydro has raised warrant further examination to determine how much affect they should have (CEC Argument, pp. 68-69).

JIESC cites examples which it claims provide evidence of superficial awareness of FERC practices by BC Hydro's witnesses and argues:

> "During the course of the oral hearing, BC Hydro's witnesses acknowledged they had limited or no knowledge or experience of FERC practices generally or surrounding the use of 12 CP … The only analytical data BC Hydro appeared to have looked at in reviewing the use of 1 CP versus 12 CP during the preparation of the Application was the revenue to cost sensitivity analysis contained in Figure 3 of the Application …" (JIESC Argument, p. 4).

The JIESC summarizes BC Hydro's and its own positions and submits the following conclusions:

> "Two points follow from the above. First, at a very practical operations level, BC Hydro itself understands the importance of the winter peaks on cost causation. Second, the ratchets in rate schedules are logically inconsistent with the 12 CP method.
>
> In sum, the 4 CP methodology reflects the yearly circumstances that the system needs to be designed and built for to handle. While BC Hydro may have been justified in moving away from 1 CP, there is clearly no justification for it moving to the opposite extreme of 12 CP" (JIESC Argument, p. 10).

Terasen reiterates the recommendation of its experts for adoption of a 3 CP allocator. However, Terasen also submits that Mr. Linxwiler's analysis is sound and that a 4 CP allocator could also be appropriate as it still recognizes the pronounced winter system peak (Terasen Argument, pp. 27-28).

Corix is of the view that winter seasonal nature of the BC Hydro's system lends itself to a 3 CP or 4 CP allocation of demand. Corix supports the views of others in the RDA proceeding that believe that the 12 CP is not the correct peak demand allocator for BC Hydro (Corix Argument, p. 5).

BC Hydro submits that while it is true that the Commission has not considered a 12 CP allocator in a comprehensive rate design proceeding, the 12 CP has been accepted for open access transmission rate design. BC Hydro further submits that the LOLP evidence reflecting the impact of scheduled maintenance clearly supports an allocation factor calculated from more than just the winter months (BC Hydro Reply, pp. 13, 14)

Commission Determination

The Commission Panel notes that considerable evidence was presented regarding the FERC and OEB tests. It is the Commission Panel's view that these two regulatory bodies employ such tests, in part, due to the large number of utilities they regulate, and therefore while such tests are useful as a guide, at least in the case of FERC, the tests are not substitutes for consideration of the circumstances of each individual utility. This Commission does not regulate a large number of electric utilities and therefore sees little value to the application of such tests in the context of British Columbia, and prefers an examination of the circumstances particular to each utility.

When all the evidence before the Commission Panel, including references to planning from the IEP, the BCTC Capital Plan and the LRIC, and the evidence of Linxwiler and EES are considered, the Commission Panel finds that a peak demand allocator based on the winter peak is appropriate. The Commission Panel notes the evidence that the winter peak has occurred in each of the months from November through January in recent years and that the February peak is often close to the annual peak, and that BC Hydro employs a demand ratchet for the four winter months and, accordingly, views a 4 CP allocation as appropriate. For the purposes of this Decision the Commission Panel finds this to be appropriate for both transmission, and demand related generation costs, but notes that further investigation may be worthwhile. **BC Hydro is directed to recalculate its FACOS based on a 4 CP allocation of transmission and demand-related generation costs in accordance with Order No. G-111-07.**

3.4.2 Distribution System Demand/Customer Split

This Section summarizes the BC Hydro's proposal, Terasen evidence and other Intervenor position regarding the distribution system demand/customer split.

3.4.2.1 BC Hydro's Proposal

As part of the total BC Hydro electric system, the distribution system receives electricity from the transmission system, which operates at 69,000 volts (69 kV) and above, steps the transmission voltage down to lower primary distribution level voltages normally from 12 kV to 25 kV, transports the electricity along a system of primary distribution lines, steps the primary voltages down to secondary voltages and then ultimately supplies customers through individual meters and services.

In the 2007 RDA BC Hydro states its review of the distribution system consisted of a review of distribution capital assets and sub-functionalization of the capital assets into the following categories:

- distribution wires;
- distribution transformers; and

- street lighting.

BC Hydro’s allocation of distribution system costs can be summarized as follows:

1. The distribution wires system costs were allocated to rate classes where customers are connected to the distribution system, which effectively means all rate classes except transmission customers. Those costs were then classified as 75 percent demand related and 25 percent customer related. BC Hydro states that the allocation is “based on experience and the practices of other distribution utilities”. The majority of the distribution system is typically designed to meet the system demand while local facilities are designed to connect the customer and therefore the majority of costs are classified as demand related (Exhibit B-1, p. 22).

2. The distribution transformer system includes the cost of the step down transformer. This system was also classified as 75 percent demand related and 25 percent customer. Rate classes that take primary service do not make use of transformers and were not allocated any cost associated with distribution transformers (Exhibit B-1, p. 22).

3. The Street Lighting system costs were allocated by way of direct assignment (Exhibit B-1, p. 22).

4. Customer Care Costs were classified as 90 percent customer related and 10 percent revenue related; in other words none of these costs were treated as demand related in the current study (BC Hydro Argument, p. 34).

In cost of service studies the distribution system is commonly split between the portion of the system which was constructed solely as a result of the customer requiring service, of which customer metering is the most common example, and the portion of the system constructed because of the demand placed on electrical equipment. Distribution substations are generally classified 100 percent demand, and all equipment between this point and the meter may be determined to be demand or customer-related.

The methods used to determine the demand/customer split are more fully described by EES:

> There are three basic methodologies to classify distribution costs: basic customer charge (sometimes called 100% demand), minimum system and zero intercept. Variations around these three basic methods are also common. The basic customer charge methodology assumes that the distribution system is built to meet the customers’ non-coincident peak demand. Therefore, the basic customer

> charge methodology classifies customer accounting, and O&M and capital costs for meters and services as customer-related, while the remaining distribution costs are classified as 100% non-coincident demand-related. Distribution costs are also sometimes split between demand and customer according to a zero intercept or minimum system methodology. These methodologies reflect the philosophy that the distribution system is in place in part because there are customers to serve throughout the service territory expanse, and that a zero or minimally-sized distribution system is needed to serve these customers even if they only have a 100 watt light bulb in their residences. The concept follows that any costs associated with a system larger than this minimal size are due to the fact that customers "demand" a delivery quantity of electricity greater than the minimum. These costs required to meet demands greater than those met by the minimum system are treated as demand-related (Exhibit C7-4, Testimony of EES Consulting, pp.16, 17).

BC Hydro did not perform either a minimum system or zero intercept analysis for the purposes of the 2007 RDA.

BC Hydro states that it "has historically used 75/25 demand/customer split for classification of its distribution system" (Exhibit B-3 BCUC 1.2.1) and that in the 1998 Cost of Service Study, which pertained to the 1996/1997 fiscal year, "the revenue requirement related to the primary distribution system was classified as 73 percent demand and 27 percent customer", and that in the cost of service study related to the 1995/1996 fiscal year "the revenue requirement related to primary distribution was classified as 75 percent demand and 25 percent customer" (Exhibit B-63). BC Hydro was asked to provide the demand/customer split for each cost of service study performed since 1995, and to describe the methodology employed. In response BC Hydro stated the 1998 study used a 73/27 percent split based on a distribution system analysis which is similar to a minimum system analysis, but did not provide study results (Exhibit B-3 BCUC 1.21.1). Mr. Reimer testified that the last BC Hydro minimum system analysis he had seen was from 1990 (T5:117). Commission counsel enquired why BC Hydro did not consider it important to update the study to which BC Hydro responded in part:

> MS. SOFIELD: A: The reason that we didn't consider it necessary for this RDA to go back and have a new study undertaken was I think we were pretty comfortable that he 75/25 was not contentious. We thought it wasn't, from the previous times that we'd been having discussions and debates on this methodology. We felt that there was enough evidence from other industry

> practices that it could be supported, and that we did in fact have other priorities that we wanted to consider with regard to the study.
>
> More specifically around the impact on RC ratios, I think we have demonstrated through IRs that clearly this is one of those assumptions that once it's changed it can have some impact … (T7:1118).

3.4.2.2 Terasen Evidence

The EES written evidence filed by Terasen recommends that distribution plant should be classified to demand and customer, based on a minimum system method (Exhibit C7-4, p. 28). EES also recommends that:

- BC Hydro develop the appropriate data to perform a minimum system-type analysis, including the determination of an appropriate Peak Load Carrying Capability ("PLCC"), if any.
- In the interim, BC Hydro classify all distribution facility costs as 50 percent demand and 50 percent customer and the PLCC credit should be set to zero pending proper calculation.

Which portion or portions of the distribution system should be classified as 75 percent demand was the subject of questioning during the proceedings. EES stated that BC Hydro's past cost of service studies when they have performed minimum system analyses indicated a demand customer/split of 53/47 percent (T9:1531). In order to examine the apparent discrepancy between the 75/25 and 53/47 ratios, Commission counsel requested the prior BC Hydro studies on which EES had relied and asked EES to produce a summary to show, among other things, the demand/customer split for the revenue requirement contained in these studies. The two studies: the 1995/96 FACOS filed as Exhibit 14 in the BC Hydro 1996 WTS Application and the 1996/97 FACOS filed as response to IRs in the same WTS proceeding, and summaries from each study of the demand/customer split for both distribution O&M expense and distribution depreciation and amortization expense were provided. No summary was provided for revenue requirement in total. Exhibit C7-21 Revised provided functionalized distribution revenue requirement from the 1996/97 FACOS found at Schedule 3 page 1 of 23 of that study, and it is summarized for the distribution function only as shown in Table 3-5 below. It shows that when the total distribution function revenue requirement is considered, that 62 percent was classified as demand in that study.

Table 3-5

Functional Classification of Rate Base and Revenue Requirement (Extract of Distribution Classification)

			$000s	
1	Primary Demand	$	184,441	
2	Primary Customer	$	66,725	
3	Secondary Demand	$	74,263	
4	Secondary Customer	$	53,124	
5	Service Customer	$	23,938	
6	Meter Customer	$	17,350	
7	Total Distribution (ex. Lighting and Other)	$	419,841	
8=1+2	Total Primary	$	251,166	
9=1+3	Total Demand	$	258,704	
	SUMMARY STATISTICS			
10=1/8	Primary Demand as a Percent of Primary Total			73%
11=9/7	Total Demand as a Percent of Total Distribution			62%

(Derived from Exhibit C7-21 Revised 1996/97 FACOS Schedule 3, p. 1 of 23)

BC Hydro states that in the current FACOS it did not apply the 75/25 demand/customer split to all of its distribution costs, and that care must be taken in comparing the current study to previous studies. BC Hydro submits that if meter costs, direct-assigned street lighting costs and customer care costs are also considered then the “weighted average” demand/customer classification in the current study is 61/39, not 75/25, and provided a summary table (BC Hydro Argument, p. 34).

EES also provided a study it performed on behalf of the OEB to summarize distribution classification and allocation methodologies used by a significant sample of utilities across Canada and the US. In lieu of a BC Hydro-specific study, EES states that the survey results supports the application of a 50/50 demand/customer split applied to all distribution facilities accounts in the BC Hydro cost of service study. In coming to this conclusion EES considered a subset of the utilities sampled and stated that based on the full survey results 64.7 percent would be demand related and

35.3 percent customer-related but this result was not valid because it included utilities that used the Basic Customer Methodology which EES stated was not applicable to the BC Hydro system (Exhibit C7-7, BCOAPO 1.2.2).

EES recommends that BC Hydro prepare a minimum system type study with a peak load carrying capability ("PLCC") adjustment, which it states would tend to increase the costs allocated to demand (Exhibit C7-4, pp 17-21). EES estimated that the cost of performing a minimum system analysis for BC Hydro would be $10,000-$15,000 (T9:1617). EES testified that an appropriate range for the demand/customer split is from 60/40 to 40/60 (T9:1531). EES further testified that Ontario is the only jurisdiction in the Canada and United States which performs a PLCC adjustment (T9:1571).

Terasen notes BC Hydro's statement that it "may" include a minimum system analysis in its next distribution system study and argues that the Commission should set a firm timetable whereby BC Hydro undertakes the necessary minimum system study (Terasen Argument, p. 16).

3.4.2.3 Other Intervenor Submissions

BCOAPO submits that BC Hydro's proposed 75/25 split should be adopted for purposes of the current FACOS methodology. However, BCOAPO does support Terasen's call for BC Hydro to undertake a minimum system-type analysis, including the determination of the appropriate PLCC credit. BCOAPO states that it agrees with the BC Hydro witness that reviewing such practices elsewhere can be instructive but not determinative of what the demand/customer split should be for BC Hydro (BCOAPO Argument, pp. 14-15).

The CEC argues that BC Hydro's proposed allocation of distribution costs should not be accepted and that the Terasen evidence appears persuasive. The CEC also submits that BC Hydro should conduct further studies to address this issue and the 75/25 demand customer split should be moved to 50/50 as supported by the Terasen evidence (CEC Argument, p. 49).

FortisBC submits that BC Hydro should undertake a minimum system study to support its proposed distribution classification method. Fortis BC states it is common to look at past precedents for the utility as well as practices of other utilities (FortisBC Argument, p.2).

In Reply, BC Hydro submits that the use of 75/25 split as found in the RDA is much more consistent with previous FACOS studies than is a 50/50 allocation and restates its commitment to undertake a distribution classification study and incorporate the results in its next comprehensive rate design application and further submits that it should be given the latitude to select the most appropriate type of study and that it would be premature for the Commission to determine at this time that a minimum system study with a PLCC adjustment is the most appropriate type of distribution classification study for BC Hydro (BC Hydro Reply, p. 18).

Commission Determination

The Commission Panel is of the opinion that BC Hydro's imprecise description of the portions of distribution plant which were allocated based on demand and customers clouded the understanding of this issue. The Commission Panel is further concerned that BC Hydro has not studied its distribution system since 1990, and should have understood the importance of the issue. **Considering past practice, and the results of the entire EES study, the Commission Panel determines that an allocation of the total distribution revenue requirement, from primary to meters and including related customer care costs and directly assigned street lighting on a 65 percent demand, 35 percent customer basis is appropriate and directs BC Hydro to revise its FACOS accordingly, as directed in Commission Order No. G-111-07.**

Further, BC Hydro is directed to conduct both a minimum system and zero intercept analysis for inclusion in its next FACOS or rate design filing.

3.4.3 Generation Demand/Energy Split

BC Hydro states that its overall generation system has typically been energy constrained (energy related reliability criteria are more constraining than demand related reliability criteria), and additional hydro generating facilities have been added to address forecast energy requirements.

While the additional facilities are required for energy production, they also result in additional capacity, which is required to meet customer demand.

For these reasons BC Hydro states that in the FACOS it has classified hydro plant as 50 percent demand and 50 percent energy and its thermal plant as 100 percent demand related. Thermal plant was built for capacity to meet the demand during heavy load periods and is not required for large scale energy production. BC Hydro states that the assumption of hydro plant being classified as 50/50 demand/energy split is assessed as reasonable and is consistent with past practice (Exhibit B-1, p. 21).

BC Hydro testified that the generation function is the largest BC Hydro function and constitutes over one half of the total revenue requirement (T5:676-7).

When asked if the demand/energy split for hydraulic generation was the same as that used in the 1991 COS study BC Hydro replied that the split has been employed since 1994 (Exhibit B-3, BCUC 1.17.3) and that prior to that a 39 percent demand 61 percent energy split had been used. This classification was based on hydro plant being energy-related and other facilities being demand-related (Exhibit B-3, BCUC 1.17.4). When asked to explain, in detail, why hydraulic generation was split 50/50 demand/energy BC Hydro provided the following response but did not provide any of the studies described therein:

> "It is not possible to develop an accurate, planning based classification of hydro plant between demand and energy. When hydro plant is built, it provides both energy and capacity and one cannot be obtained without the other. Various rationale have been used to separate demand from energy related costs, such as equating costs to develop water pressure (head) as being demand related costs. Such costs would include the cost of the dam itself without turbines. This rationale would indicate demand related costs amount to approximately 55 percent of the total costs. Other rationale based on system load factor indicates that demand related costs account for 45 percent or less of the total costs. Other rationale includes the use of a proxy gas turbine to determine capacity costs. All these rationale support an allocation of 50 percent demand and 50 percent energy" (Exhibit B-3, BCUC 1.17.2).

BC Hydro submits that the practice that hydraulic generation plant is allocated 50/50 demand/energy is a long-standing practice that BC Hydro relied on, and that no party provided evidence to challenge this judgment. BC Hydro states the sensitivity of this assumption is not large, as was shown in response to BCUC 1.23.1 (BC Hydro Argument, pp. 26-27). BC Hydro's expert witness testified that he was not fully aware of how hydraulic plant was allocated in other provinces (T5:674), and that he did not have any information as to the practices in other provinces or elsewhere (T5:675), but that it was his understanding that the "B.C. Hydro system is energy constrained, and generally the additions to generation were done for energy reasons, to provide more energy to B.C. Hydro" (T7:1161).

The Commission Panel Chair inquired as to the impact of a 50/50 split going forward, and asked:

> THE CHAIRPERSON: …I'm just wondering, having been part of the Panel which recently deliberated on Revelstoke 5, which is a large expensive turbine which, if I follow your logic on a go-forward basis, would be allocated 50/50 between demand and energy. Whereas the evidence overpoweringly before the Panel was that the benefits it brought were demand.
>
> MS. SOFIELD: A: That's correct in terms of the Revelstoke 5 application, yes (T8:1262-1263).

BC Hydro submits that hydro plant produces both energy and capacity and the two are inseparable, and therefore, judgment will always be required to distinguish the two for the purpose of a cost of service study.

BCOAPO submits that new approaches to classifying generation costs are emerging (T5:676) and BC Hydro's current classification for thermal and hydro plant was established over 10 years ago (Exhibit B-3, BCUC 1.17.4), it would be reasonable for BC Hydro to initiate a review of its Generation classification practices if FACOS is not to be discarded (BCOAPO Argument, p. 13).

The CEC submits that BC Hydro's evidence "has gone largely untested" and recommends that the Commission "concur with the BC Hydro allocation" (CEC Argument, p. 70)

In reply, BC Hydro submits that since it has examined the sensitivity of R/C ratios to changes in the demand/energy ratio and found little difference, that there is no merit in undertaking a detailed review of generation classification at this time (BC Hydro Reply, p. 12)

Commission Determination

The Commission Panel notes that BC Hydro's sensitivity analysis showed the impact on R/C ratios of assuming 100 percent demand or 100 percent energy, when the demand allocator was 12 CP. It provided no further sensitivities when the demand allocator was 1, 3 or 4 CP.

The Commission Panel considers that BC Hydro should have included in its Application, or in other materials, an update of the study upon which it relied for the 50/50 demand/energy split. The Commission Panel is concerned that the use of a static allocator like 50/50 will fail to reflect an accurate allocation if future Resource Smart additions at Revelstoke and Mica are all predominantly capacity related.

For purposes of this Application the Commission Panel finds a 55 percent demand 45 percent energy split using the demand (head) approach is reasonable absent a detailed study and BC Hydro is directed to recalculate the FACOS accordingly, as directed in Commission Order No. G-111-07.

Further, BC Hydro is directed to include a detailed analysis of this issue as part of its next FACOS or rate design filing.

3.4.4 DSM Cost Allocation

In the 2007 RDA all revenue requirement related to demand-side management is allocated 10 percent to Transmission and 90 percent to Distribution. Since there appeared to be conflicting evidence from BC Hydro as to how DSM costs were allocated, counsel for JIESC requested an undertaking regarding the allocation of DSM costs (T5:827) The Question and Response are found in Exhibit B-28:

> QUESTION: Confirm whether DSM costs are allocated 90 percent to distribution and 10 percent to transmission, or 90 percent to generation and 10 percent to transmission.
>
> RESPONSE: The COS study in the 2007 RDA functionalizes capitalized DSM 90 percent to <u>distribution</u> and 10 percent to transmission, as Mr. Reimer noted at Transcript Volume 4, Page 650, Lines 17 - 21. BC Hydro's response to BCOAPO IR 2.19.2 is incorrect, as was Ms. Sofield's testimony, made in reliance on that response at Transcript Volume 4, Page 648, Lines 3 -10. A revised copy of BC Hydro's response to BCOAPO IR 2.19.2 is attached.)

BC Hydro states that within the IEP filing, Power Smart/DSM is presented as a resource that is and will continue to be used to meet future load growth of all customers in the same manner as new IPP purchases and Resource Smart additions (Exhibit B-7 BCOAPO 2.19.3), and that approximately 55 percent of DSM capital related costs are allocated to the residential rate class, and approximately 3 percent of the DSM capital related costs are allocated to the Transmission rate class (Exhibit B-7, BCOAPO 2.19.4). BC Hydro further confirmed that there has been no direct assignment of DSM costs to customer classes (Exhibit B-3, BCUC 1.22.2). Table 5 of Appendix P of BC Hydro's F07/F08 Revenue Requirement filing shows that planned total DSM expenditures for years 2003 to 2012 are approximately $124 million for industrial, $126 million for Commercial/Government, $95 million for Residential and $96 million for General Awareness campaigns (Exhibit B-7, BCOAPO 19.0).

BC Hydro also testified that it allocated DSM costs in the manner that it did in order to be consistent with the 1998 WTS Decision:

> MS. SOFIELD: A: I think that as well as being consistent with how we saw the WTS decision, which was the 90 percent to distribution, we felt that overall that that wasn't unreasonable since DSM savings are for the benefit of all ratepayers. But I think there's a rationale that said they could be – you could also argue from a fairness perspective that to allocate them via the generation functionalization would be reasonable (T7:1148-1149).

BC Hydro submits that upon reflection it observes that DSM capital-related and operating costs are incurred to serve load and that the savings occur primarily in generation, and thus it would not be inappropriate to functionalize these costs as 90 percent generation 10 percent transmission. BC Hydro proposes to reflect Commission directions on this topic in the FACOS filed with its next comprehensive rate design application, but states that there is nothing on record in this proceeding that would allow it to show how such a change would impact its re-balancing proposals (BC Hydro Argument, p. 23).

CEC, BCOAPO and JIESC submit that DSM costs should be functionalized as 90 percent generation and 10 percent transmission (BCOAPO Argument, pp.11-13; CEC Argument, p. 41; JIESC Argument, p. 24). JIESC further recommends that the portion functionalized to generation be allocated 50/50 percent based on demand/energy). Terasen submits the Commission should establish a timetable for review of this issue (Terasen Argument, p. 28). BC Hydro re-iterates its position that DSM costs ***should*** be functionalized as 90 percent generation 10 percent transmission in BC Hydro's next comprehensive rate design application (BC Hydro Reply, p. 9) (emphasis added).

The CEC produces a detailed calculation that it references to the Application and which, it states, shows the impact on R/C ratios of refunctionalizing the DSM costs in the manner it recommends. (CEC Argument, pp. 41-47).

In reply, BC Hydro submits that this calculation crosses the line between evidence and argument and that the Commission must disregard what BC Hydro characterizes as this new evidence (BC Hydro Reply, pp. 8, 9).

Commission Determination

On the balance of the evidence before it and without regard to the CEC submission in Argument, the Commission Panel finds that the functionalization of all revenue requirement related to demand-side management 90 percent to generation and 10 percent to transmission is appropriate. It also finds it appropriate that the portion functionalized to generation is

allocated to the customer classes in the same proportions that the total generation revenue requirement is allocated to the customer classes, and directs BC Hydro to recalculate its FACOS accordingly, as directed in Commission Order No. G-111-07.

3.4.5 Powerex Net Income

BC Hydro describes the eligible subsidiary net income as being allocated based on generation gross plant in service but shows that all of the income is classified to energy (Exhibit B-1, Appendix A, Schedule 3, p. 3). This is because the primary component of subsidiary net income is Powerex net income, which BC Hydro perceives as associated with energy sales. Powerex net income is capped at $200 million per year for this purpose.

BC Hydro explained this as follows:

> "From a rate design perspective, Powerex net income is functionalized to Generation and then classified as energy-related, consistent with the treatment of the cost of energy.
>
> Powerex's net income is generated by optimizing the value of the excess capability of BC Hydro's system and by off-system trading. From a rate design perspective, the level of income is not directly attributable to the cost of either energy or capacity and furthermore any attribution would by its nature vary from time to time. In BC Hydro's view, it is appropriate to treat Powerex net income in the same manner as market electricity purchases, therefore effectively an offset to the cost of energy" (Exhibit B-3, BCUC 1.15.1).

BCOAPO's witness Mr. Fussell offered a somewhat different view as to the reason that Powerex is able to generate significant income in response to a question from Commissioner Milbourne:

> MR. FUSSELL: A: I think you've got to be careful when you're looking at export, because to a great extent Powerex, if you look at their export capability, the majority of their export is not selling B.C. Hydro energy or energy that's been produced in B.C. The majority of that export activity that they undertake are basically by -- they're buying energy throughout the Pacific Northwest or Alberta and they're reselling energy. And what they're really using is the capacity within the B.C. Hydro to back up that export. A lot of that stuff is done on a back-to-

> back basis, but what you have is the guarantee of the B.C. Hydro system. If you can't find a sale for some of that energy that you purchased, you then bring it back into the system. If you can't, on the other side of the transaction, if you can't -- if you haven't got enough capacity to serve the loads, all the loads that you've actually contracted to sell to, you have the B.C. Hydro system. You have capacity within the system to complete that sale.
>
> So, if you look at -- over the years, when I looked at it, Powerex sort of -- total transactions are something in the order of 30,000 gWh [GW.h] a year. The actual energy that they bring back into B.C. Hydro system -- in other words, they're backing off generation here and bringing energy back into the system, typically runs between four and five thousand gWh [GW.h] a year. The actual sales of B.C. Hydro energy, energy produced within B.C. over the last number of years has been negative. So I think you've got to be careful when you say that, you know, we're exporting. I think it largely depends -- we have some spare -- I mean, B.C. Hydro has some spare storage capacity in which they can bring energy back into the system. But the big thing that allows them to actually compete effectively in the market is the generation capacity. It's the available -- having available generation capacity to actually back up those export sales (T4:521-522).

BC Hydro was questioned regarding Mr. Fussell's testimony by Commission counsel:

> MR. FULTON: Q: Great, thank you. Would you agree with me that Powerex's net income is primarily related to its shaping capabilities?
>
> MS. SOFIELD: A: Powerex earns its income from not just trading from B.C. Hydro's system but also off-system trading. So, and that does vary from year to year, so I don't want to be too specific in my response except to say that yes, they have the advantage of being able to use the shaping and storage.
>
> MR. FULTON: Q: Yes, and I prefaced -- well, I included in my question at least the word "primarily". So would you agree with me at least to the extent that the net income of Powerex is primarily related to its shaping capabilities?
>
> MS. SOFIELD: A: I think that's fair. I mean, in that first sentence of that second paragraph in the BCUC 1.15.1, we talk about how the net income is generated and I think, yes, it's fair to say primarily it's from the optimizing the value of the excess capability.
>
> MR. FULTON: Q: Okay, and would you also agree with me that shaping capabilities are a function of capacity and not energy?
>
> MS. SOFIELD: A: I think it actually relates both to energy and capacity. It's the storage of the energy from season to season that allows us to take – that is the shaping element of that.

> MR. FULTON: Q: All right. Well, would you agree with me that it's primarily -- that shaping capabilities are primarily a function of capacity and not energy?
>
> MS. SOFIELD: A: Yes, I would agree with that. (T7:1150-51)

The determination of BC Hydro's and Powerex's share of trade revenues is governed by the Transfer Pricing Agreement ("TPA"). BC Hydro described the TPA as being best understood as an accounting or management mechanism which allocates the market value of the system storage between the two parties to maximize the overall value of the system (Exhibit B-46 attached excerpt from BC Hydro Evidence Regarding BCTC Network Economy Tariff Application, p. 61).

BCOAPO disagrees with BC Hydro's position:

> BCOAPO submits that Powerex Net Income should be classified as both demand and energy based on the overall classification of BC Hydro's Heritage Resources (including associated cost of energy and GRTA). The resulting classification would be roughly 38% demand and 62% energy (Exhibit B-1, Appendix A, p. 3). (BCOAPO Argument, p. 13).

In reply, BC Hydro submits that BCOAPO's position is based on the incorrect premise that Powerex net income is earned solely by taking advantage of the system's capacity and storage capability and that it remains of the view that it is appropriate to treat Powerex net income as an offset to the cost of energy (BC Hydro Reply, p. 11).

Commission Determination

The Commission Panel finds that Powerex Net Income results from both capacity and energy availability on BC Hydro's system, but finds that definitive evidence as to the split between capacity and energy was not presented and therefore determines that for the purposes of this FACOS, Powerex Net Income shall be allocated to customers classes in the same proportions that the total generation revenue requirement is allocated and directs BC Hydro to revise its FACOS accordingly, as directed in Commission Order No. G-111-07.

3.4.6 IPP Contract Power Purchases

BC Hydro classifies IPP purchases as energy-related in the FACOS. The classification of these purchases as energy-related is consistent with BC Hydro's position as a net importer with sufficient reservoir storage capacity to purchase energy at various times throughout the year. Specifically, BC Hydro submits that the primary purpose for entering into agreements with IPPs is the procurement of additional energy and that all costs associated with IPP contracts are appropriately classified as energy-related (BC Hydro Argument, pp. 25-26).

By way of an undertaking, in response to questioning by Commission counsel (T7:1156-1157), BC Hydro described the impact of capacity on the ranking in the Call and price paid to an IPP:

> QUESTION:
>
> a) For the ranking of IPP projects in BC Hydro's last call, did capacity improve a project's ranking?
>
> b) In the last call, were projects providing firm energy more highly valued than those provided no firm energy?
>
> RESPONSE:
>
> a) As noted in the response to BCUC IR 1.16.1, in the F2006 Call the capacity benefit associated with hourly firm energy (relative to tenders offering monthly firm energy) was reflected as an evaluation adjustment, but there is no extra payment for capacity.
>
> b) In the F2006 Call, all Large Project bidders were required to tender a firm energy profile, either monthly or hourly. The evaluation of the Large Project tenders was based on the levelized bid price for firm energy; non-firm energy did not factor into the evaluation process. Further, non-firm energy generated by Large Projects was subject to discounted pricing. For the Small Project stream of the F2006 Call, all tendered energy quantities were considered to be contractually non-firm (Exhibit B-64).

In an exchange with the Panel Chair beginning at T8:1264 the BC Hydro witnesses were asked whether BC Hydro had considered that there was capacity associated with the Island Cogeneration Project ("ICP") IPP project:

> MS. SOFIELD: A: Well, I couldn't yesterday and I still can't, Mr. Chair, unfortunately. My line of inquiry hasn't quite provided me with enough information. I think all I would say is that we -- in doing the cost of service study we haven't gone down to the level of identifying the individual IPP contracts and determining which way, what benefits we were getting from them or indeed looking at the terms of the contracts. We've looked at the overall cost of energy coming from IPPs, made a judgment that it was reasonable that should be allocated on the basis of energy (T8:1265).

Immediately prior to this answer, BC Hydro's expert witness Mr. Reimer testified that he had not specifically looked at the ICP contract but that he had looked at the 2006 IEP decision and it was clear that both energy and capacity planning criteria had been used and that while the energy planning criteria were dominant, both criteria came into play, and that that was really the basis for system additions, rather than individual contracts (T8:1264-5).

BCOAPO agrees with BC Hydro that IPP purchases should be allocated based on 100 percent energy since the BC Hydro system is energy constrained and there were no capacity related monetary payments resulting from the F2006 Call (BCOAPO Argument, p. 12). The CEC believes that IPP supply does provide capacity benefits and recommend the Commission to instruct BC Hydro to prepare an analysis immediately so as to be incorporated into the final rate design changes through subsequent submission to the Commission (CEC Argument, p. 40).

BC Hydro submits that it will reflect any future capacity payments made to IPPs in the classification of IPP contract power purchase costs in its next comprehensive RDA, and that there is no value in further analysis of the issue at this time (BC Hydro Reply, p. 11).

Commission Determination

The Commission Panel is of the view that IPP contracts, of which the ICP may be a key example, do provide capacity benefits, and that the fact that the contract rates are based solely on energy is not determinative. However, at this time there is insufficient evidence as to the capacity benefits from these contracts and BC Hydro's allocation is accepted as proposed. **BC Hydro is directed to prepare a study, for inclusion in its next FACOS or rate design filing that examines and quantifies the capacity benefits associated with IPP contracts.**

3.4.7 Power Planning and Portfolio Management

BCOAPO questioned the BC Hydro panel at some length regarding the appropriate treatment of power planning and portfolio management ("P3M") costs. BC Hydro confirmed that this function is part of the distribution line of business, and it also confirmed that the role of the department was to manage IPP purchases and further confirmed that the costs were functionalized as distribution (T4:654-655).

When counsel for BCOAPO suggested that this cost might be more properly functionalized as generation, BC Hydro disagreed stating, in part, that they had to make some pragmatic decisions as to where costs should go and this one was not unreasonable (T4:655), and that this decision was a judgment call (T4:657). BC Hydro agreed under cross-examination that this department purchased IPP power in part on behalf of industrial customers but that the costs had been allocated entirely to distribution customers (T5:660,661). BC Hydro stated that this type of judgment call was an example of why a range of reasonableness was required for revenue/cost ratios when setting rates (T5:653).

BC Hydro now submits that upon reflection, the P3M function provides a service to all customers, including those who are not connected to the distribution system, and that it would not be inappropriate to functionalize these costs as 90 percent generation 10 percent transmission. BC Hydro proposes to reflect Commission directions on this topic in the FACOS filed with its next comprehensive rate design application, but states that there is nothing on record in this proceeding that would allow it to show how such a change would impact its re-balancing proposals (BC Hydro Argument, p. 23).

Both the CEC and BCOAPO recommend that P3M costs be functionalized as generation. (BCOAPO Argument, pp.11-13; CEC Argument, p. 41) while the JIESC recommended the same functionalization with costs allocated on a 50/50 percent demand/energy basis (JIESC Argument, p. 24). In its Reply, BC Hydro re-iterated its position that P3M costs ***should*** be functionalized generation in BC Hydro's next comprehensive rate design application (BC Hydro Reply, p. 9) (emphasis added).

The CEC produced a detailed calculation that it references to the Application which it states shows the impact on R/C ratios of re-functionalizing the P3M costs per its recommendation (CEC Argument, pp. 41-47).

In Reply, BC Hydro submitted that this calculation crosses the line between evidence and argument and that the Commission must disregard what BC Hydro characterizes as the new evidence (BC Hydro Reply, pp. 8, 9).

Commission Determination

On the balance of the evidence before it, without regard to the calculation in CEC Argument, the Commission Panel finds that P3M costs are incurred for the benefit of all customers and should be allocated to customer classes in the same proportions as total generation revenue requirement and directs BC Hydro to recalculate its FACOS accordingly, as directed in Commission Order No. G-111-07.

3.4.8 Deferral Account Recoveries

BC Hydro functionalizes all deferral account recoveries to generation:

> MR. FULTON: Q: Okay. And can you tell us why each of those -- why it's appropriate to functionalize each of those accounts to generation?
>
> MS. SOFIELD: A: So the Heritage deferral account and the non-Heritage deferral account are primarily driven by the variance between B.C. Hydro's forecast of its cost of energy, either Heritage or non-Heritage energy, and what it actually incurs in any one year. So for those two accounts, there's a very strong relationship between cost of energy and therefore seems reasonable and appropriate to functionalize the recovery of those deferral accounts to generation.
>
> The trade income deferral account is again related to the Powerex net income, which we've just had the discussion on. So as we are allocating the Powerex net income itself to generation, because we believe that that's reasonable, the difference between forecast trade income and what we actually earn which is in this deferral account is also related to – also relates directly to that -- to energy, and therefore is functionalized as generation.
>
> The BCTC deferral account is a timing difference between BCTC's filings and their costs and ours. It's a rather immaterial amount in terms of the overall value of our deferral accounts, as I think you can see from the filing of the deferral account balances we made this morning. So for convenience it's rolled into the energy, generation functionalization (T7:1154-1156).

BCOAPO agrees that the Heritage Deferral Account ("HDA"), Non-Heritage Deferral Account ("NHDA") and Trade Income Deferral Account ("TIDA") should be functionalized as Generation; however, BCOAPO submits that the BCTC Deferral Account ("BCTCDA") should be functionalized as Transmission. In terms of classification, BCOAPO submits, the HDA and NHDA should be classified as energy and the TIDA should be classified on the same basis as Powerex Net Income (BCOAPO Argument, p. 20).

In Reply, BC Hydro submits that BCOAPO is the only Intervenor to address in Argument the functionalization of deferral account balances. It agrees with BCOAPO regarding the allocation of the HDA and NHDA balances on an energy basis but does not agree with BCOAPO regarding the allocation of TIDA balances. BC Hydro agrees with BCOAPO position that the BCTCDA balance could be functionalized as transmission. BC Hydro states, however, that the balance was small and not material and therefore was functionalized in the same manner as the other deferral account balances (BC Hydro Reply, p. 10)

Commission Determination

The Commission Panel finds that this issue should have been addressed by BC Hydro in its FACOS study.

Accordingly, in future FACOS studies BC Hydro is directed to treat the revenue requirement related to the Trade Income Deferral in the same manner as Powerex Net Income, and the BCTC Deferral Account is to be functionalized to transmission.

4.0 RATES

This section of the Decision addresses BC Hydro's various Rate Schedules, their history and BC Hydro's proposals for them in the 2007 RDA.

4.1 Residential Rates

4.1.1 Residential Rate Schedules under Zone I Tariff

BC Hydro provides service to its Residential customers primarily under the following Zone I Rate Schedules:

Table 4-1

Rate Schedule	Description
1101	Residential Service
1105	Residential Service - Dual Fuel (Closed)
1121	Multiple Residential Service
1111	Residential Service - Common Use
1131	All Purpose Multi-Residential Service
1133	All Purpose Multi-Residential Service

(Derived from Exhibit B-1, pp. 32-33, Appendix D)

Rate Schedule 1105 will be discussed in Section 4.2 of this Decision.

4.1.2 Rate History

BC Hydro states that Rate Schedule 1101 is a flat rate with only one block of energy, which had a declining block structure until 1992 when BC Hydro applied to replace the declining block structure with flat rates in order to provide a more appropriate price signal to its residential customers. The Commission agreed with the request and directed BC Hydro to achieve flat rates over two rate increases for residential customers on April 1, 1994 (Exhibit B-3, BCUC 1.44.3).

Presently, BC Hydro's residential rate comprises a Basic Charge of $7.38 per (two month billing) period and a charge for all energy consumed of 6.15 cents per kW.h.

4.1.3 Customer Data

In response to an inquiry from the Commission Panel BC Hydro provided a table showing the distribution of the consumption of its residential accounts, based on F2005 data:

Table 4-2

Monthly Consumption	Number of Accounts	% of Residential Accounts
0-100 kWh	49,193	3.3%
100-200 kWh	106,856	7.1%
200-500 kWh	382,140	25.5%
500 - 1,000 kWh	542,249	36.2%
1,000 - 2,000 kWh	347,016	23.1%
2,000 - 5,000 kWh	66,374	4.4%
5,000 - 10,000 kWh	4,576	0.3%
> 10,000 kWh	1,250	0.1%
TOTAL	**1,499,384**	**100.0%**

Source: Exhibit B-74, p. 2

BC Hydro states that a high level analysis of the 1,250 residential accounts in the over 10,000 kWh/month category has shown that approximately 40 percent (500) are apartment building common use areas, 40 percent (500) are farms and 13 percent (160) are single family dwellings (Exhibit B-74).

4.1.4 BC Hydro's Proposed Changes to Its Residential Rate Schedules

Multiple Residential Service

BC Hydro is proposing that residences with a single secondary suite not be billed as a multiple residential service, and that existing customers on the Multiple Residential Service rates with a single secondary suite would be transferred to the appropriate Residential rate, thereby eliminating one of their two Basic Charges (Exhibit B-1, p. 32).

Common Areas of Multi-Residential Buildings

BC Hydro states that under its current tariff, the common areas of co-operatives and strata property buildings (whether occupied by renters or owners) are eligible for the residential rate, while the common areas of multi-residential buildings containing only rental properties are not eligible for the residential rate. The common areas are eligible for the residential rate if the electricity is used only for the common benefit of the dwellings in the multi-residential building. BC Hydro is proposing that the common use areas of all multi-residential buildings be eligible for the residential rate in order to eliminate the current inconsistent treatment of co-operatives, strata property buildings and other multi-residential buildings (Exhibit B-1, pp. 32-33).

Credit for Ownership of Transformers

BC Hydro states that under its current tariff, customers on the All Purpose Multi-Residential rates are eligible for a discount of $0.25 per kW per month for the provision of their own transformation from primary to secondary potential, but that since it is proposing to close the All Purpose Multi-Residential rates and transfer these customers to the corresponding Multi-Residential rates, it is also proposing to introduce a discount of $0.25 per kW per month for customers on a Multi-Residential rate who provide their own transformation from primary to secondary potential by the creation of Rate Schedule 1122 (Exhibit B-1, p. 33).

Tankless Water Heaters

To accommodate the introduction of tankless instant hot water heaters, BC Hydro proposes that the restriction in the Residential rate schedules on the maximum capacity of all heating elements energized at any one time in any water heater be modified to be the greater of 1,500 watts or 45 watts per litre of tank capacity (Exhibit B-1, p. 33).

Basic Charge

BC Hydro states that it is not proposing any structural changes to the Residential rate. However, to be consistent with how the Basic Charge is calculated in the billing system, the Basic Charge will be expressed on a per day basis of 12.26 cents per day, as opposed to $7.38 on a bi-monthly basis (Exhibit B-1, p. 31).

No Intervenor commented on BC Hydro's proposed changes to its Residential Rate Schedules in respect of Multiple Residential Service; Common Areas of Multi-Residential Buildings; Credit for Ownership of Transformers; Tankless Water Heaters; Basic Charge, and to terminate Rate Schedules 1111, 1131 and 1133.

4.1.5 Proposed Residential Rates Rebalancing and Inclining Block Residential Rate

In addition to the routine miscellaneous changes discussed in Section 4.1.4, as part of its rebalancing, BC Hydro is proposing a rate reduction of approximately five percent for Small General Service customers, offset by a rate increase of one percent for Residential customers. As a result of this rebalancing BC Hydro proposes that the energy charge for Residential rate customers be increased from 6.15 cents per kW.h to 6.21 cents per kW.h (Exhibit B-1, p. 30).

BC Hydro calculates the impact of its rate increase proposal as being $0.64 and $1.24 per month respectively, on consumption of 1,000 kW.h and 2,000 kW.h per month (Exhibit B-1, Appendix C, Schedule 11.0).

As part of its long-term rate strategy development, BC Hydro states that it will examine possible rate options focused on conservation and load management that include inclining block rates where the price rises as more electricity is consumed in order to more closely reflect marginal costs and encourage conservation (Exhibit B-3, BCOAPO 1.4.2, Attachment 1).

Item 3.8 of the Issues List provides as follows:

> "3.8 Would an inclining block residential rate comply with the objectives of the 2007 Energy Plan and how should the cut-off points for the blocks be established? Should the size of the first block take into consideration the impact of the Heritage Contract?" (Exhibit A-23).

BC Hydro describes inclining block rates as those where the price rises as more electricity is consumed in order to more closely reflect marginal costs and encourage conservation (Exhibit B-3, BCOAPO 1.4.2, Attachment 1).

BC Hydro makes two estimations of how an inclining block residential rate structure might look if the size of the first block took into consideration the impact of the Heritage Contract. Firstly, BC Hydro estimates that the size of the first energy block in an inclining block residential rate would be 825 kWh/month, and that if the second energy block were priced at the average incremental cost of energy (e.g., the F2008 RRA forecast of 7.3 cents/kWh, including losses), then the price of the first energy block would need to be set lower than the proposed residential energy charge of 6.21 cents/kWh in order to recover the same total revenue from the residential rate class and that a higher incremental cost of energy or a smaller first energy block would result in an even lower price for the first energy block. Secondly, assuming a second energy block rate of 8.8 cents/kWh and a first energy block of 825 kWh/month, and revenue neutrality, the first energy block rate would be approximately 4.7 cents/kWh (Exhibit B-7, BCUC 2.74.1).

In response to a Commission Panel IR, BC Hydro confirms that as the number of residential accounts goes up, all else being equal, the size of the Heritage Energy block per residential account would decrease. BC Hydro expects that, all else being equal, the size of the Heritage Energy block per residential account would decrease to approximately 730 kWh/month by 2016 and to approximately 635 kWh/month by 2026, based on the December 2006 load forecast (Exhibit B-10, Commission Panel 1.6.0).

BC Hydro points out that under such a rate structure:

- customers with low energy consumption (such as condos and non electrically heated homes) could pay significantly less than under the status quo while customers with high energy consumption (in particular electrically heated homes) could pay significantly more than under the status quo, which might result in the benefits of Heritage Energy being redistributed in a significantly different manner and amount;

- the marginal price signal for customers with low energy consumption would be lower than the status quo, which could result in increased consumption by these customers; and

- even electrically heated homes might have a lower marginal price signal than the status quo in non heating months, which could result in increased consumption by these customers in the non-heating months (such as for air-conditioning).

  (Exhibit B-3, BCUC 1.5.4)

BC Hydro states that it is assessing these issues as part of the development of its long-term rate strategy. BC Hydro testified that "one of the possibilities that we're looking at is being ready to engage with stakeholders and customers in the fall with the idea that depending -- and after we get a decision on this proceeding here, to come back with an application around a residential stepped rate" (T5:664).

BCOAPO states that "An equal percentage marginal cost base can facilitate the introduction of consistent company-wide price signals, for example with the introduction of time-of-use rates across all customer classes. It also leaves scope for class-specific initiatives. In the residential sector, for example, inverted block rates similar to the lifeline rates in California could be considered. Relatively low rates for an initial block could be instituted to ensure everyone has affordable access to a basic amount of electricity (with the size of the block depending on climatic conditions, dwelling type and heating mode), and much higher marginal rates established for consumption beyond the initial block" (Exhibit C6-5, p. 6).

The Commission Panel reviewed the concept of allocating the Heritage benefit to residential customers of BC Hydro by way of a "first block" basis:

> COMMISSIONER MILBOURNE: Given that and based on again what's in front of us, would you agree that there's no policy framework in place that would preclude this benefit from being shared on a "first block" basis for residential or for other customer classes?
>
> MS. SOFIELD: A: I agree that that could be one methodology that could be applied.
>
> COMMISSIONER MILBOURNE: Thank you. Would you agree that if new customers are added and new higher cost capacity added to the BC Hydro system, that the Heritage benefit would become materially diluted in both absolute and percentage terms?
>
> MS. SOFIELD: A: I would agree with that (T7:1205).

The CEC submits that the evidence suggests that a 5,000 kWh cut off point may be appropriate, but that more review of this issue is required and that it would not support the Commission ordering that including [sic: inclining] block rates be put in place as a consequence of this hearing, as there is too little evidence on the subject. The CEC submits that BC Hydro should be required to prepare a comprehensive rate strategy addressing appropriate price signaling (CEC Argument, pp. 75-76).

BC Hydro did not address the inclining block Residential rate either in Argument or Reply.

Commission Determination

The Commission Panel approves BC Hydro's proposed changes to its Residential Rate Schedules identified in Section 4.1.4.

The Commission Panel notes BC Hydro's intention to introduce an inclining block residential rate structure in the immediate future (Exhibit B-73). The Commission Panel commends this decision and finds it to be in accordance with Policy Action 4 of the 2007 Energy Plan. The Commission Panel considers that the evidence before it in this proceeding indicates that the following parameters for an inclining block rate would be suitable:

- the size of the first block should be determined on the basis of the Heritage entitlement and for each residential customer it should be set at about 800 kW.h per month;
- all energy consumed in excess of 800 kWh per month would be priced at the marginal cost of supply, as established by BC Hydro from time to time as the cost of Tier 2 power under Rate Schedule 1823, plus an allowance for distribution losses;
- the proposal be revenue neutral; and
- the proposal is to be filed with the Commission on or before March 31, 2008.

The Commission Panel considers that this rate structure will be in the public interest in that BC Hydro will be able to build on it and continue to develop innovative residential rate structures which encourage conservation and that send price signals not only to existing customers, but also to builders and developers of new residential units.

In order that this proposal can be properly understood and evaluated by all of the stakeholders, the Commission Panel determines that BC Hydro's rebalancing proposal and the resultant proposed increase of one percent to BC Hydro's Residential Rate Schedules is denied. Further to the determinations in Section 3 of this Decision, BC Hydro's proposed range of reasonableness of 90 percent to 110 percent is denied. BC Hydro is directed to file Rate Schedules for its residential class to be effective April 1, 2008, which will reflect the first phase of a three-year equal percentage phase-in to achieve the R/C ratios of 1.0 based on the revised FACOS.

BC Hydro is directed to file the revised documents referred to above with the Commission within 60 days of the date of Order No. G-111-07.

BC Hydro may wish to consider expediting its consideration of its proposed inclining block residential rate in order that it comes into effect in the phase-in process directed above.

4.2 Dual Fuel Interruptible Service (E-Plus) Rates

4.2.1 Rate Schedules

BC Hydro presently provides dual fuel interruptible service to customers with separate meters to record their electric space, water and process heating loads, under the following Zone I Rate Schedules:

Table 4-3

No.	Description
1105	Residential Dual Fuel Interruptible Service (Closed)
1205	General Dual Fuel Interruptible Service- Small Commercial Applications (Closed)
1206	General Dual Fuel Interruptible Service- Large Commercial Applications (Closed)
1207	General Dual Fuel Interruptible Service- Industrial Applications (Closed)

(Derived from Exhibit B-1, p. 41, Appendix D)

BC Hydro describes E-Plus rates, as a series of interruptible rates for which customers receive a discount for having an alternative fuel heating system as back-up and whose availability is limited to separately metered electric space, water and process heating loads (Exhibit B-1, p. 41).

4.2.2 Regulatory Background

On May 14, 1987 BC Hydro filed with the Commission an application to amend its schedule of rates by introducing the E-Plus rates. In support of its application, BC Hydro stated that as a result of restrictions imposed by the Bonneville Power Administration on its transmission intertie to California and the availability of surplus energy in the Pacific Northwest, it faced an uncertain export market over the next few years (Exhibit B-8, E-Plus 1.1.6(bb), Attachment 1).

In that application, BC Hydro stated that since it anticipated having firm surplus electricity available until about 1990/91, customers who took service under the new schedules would likely experience only limited interruptions which were not expected to exceed 120 days in the period ending March 31, 1991, after which domestic interruptible loads would be interrupted in accordance with its interruption criteria as set out in the Terms and Conditions of its Electric Tariff (Exhibit B-8, E-Plus 1.1.6(bb), Attachment 1).

BC Hydro further stated that in order to provide customers with some degree of certainty of recovering the conversion costs to take interruptible service and to add to the attractiveness of the proposed schedules, the rates in Schedules 1105 and 1205 would remain unchanged until April 1, 1991. BC Hydro further offered to finance the cost of conversion to a dual fuel heating system up to a maximum of $2,500 over a period of up to four years, at an interest rate of 8.5 percent per annum (Exhibit B-8, E-Plus 1.1.6(bb), Attachment 1).

Lastly, BC Hydro stated that the proposed rates in Rate Schedules 1105 (2.5 cents per kWh) and 1205 (2.5 cents for the first 8,000 kWh/month and 1.8 cents thereafter) exceeded its short run marginal energy costs, and recovered the costs associated with any additiona1 distribution and service faci1ities (Exhibit B-3, ESVI 1.2.5, Attachment 3; Exhibit B-8, E-Plus 1.1.6(bb), Attachment 1).

Rate Schedule 1105 contained a number of terms and conditions including:

- it was only available for residential space heating and water heating upon an interruptible basis and was not available to any building or other improvement on the customer's premises which had heating equipment connected to a natural gas distribution system. Each E-Plus customer was to have two meters, one for the electric heat load and the other for the remaining electric applications including the main fan system;

- it was applicable in Zone I only;

- BC Hydro had, at any time and from time to time, the right to interrupt the supply of electricity to the E-Plus meter "whenever there is a lack of surplus Hydro energy and the service cannot be provided economically from other energy sources". Supply could be interrupted by either manual or automatic means or by written notice by registered mail or hand de1ivery to the customer to cease the use of electricity;

- customers were required to have an installed permanent independent back-up heating system, in good working order, and an adequate supply of fuel to enable them to continue their heating operations during interruptions. The backup system had to be of sufficient capacity to supply the interrupted heating load and had to use oi1, propane, butane, wood or coal as an alternative fuel from customer owned or rented storage faci1ities located on the customers' premises; and

- BC Hydro had the right to immediately terminate the supply of electricity under this Rate Schedule to a customer who:

    - failed to maintain an installed permanent independent back-up heating system, in good working order, with an adequate supply of fuel;

    - failed to observe written notice to cease the use of electricity under the rate schedule;

    - made any use of E-Plus electricity for purposes other than space or water heating;

    - refused BC Hydro's agents access to the premises; or

    - used electricity on its E-Plus meter during a Period of Interruption, unless it could be demonstrated to BC Hydro's satisfaction that adequate standby facilities existed.

(Exhibit B-3, ESVI 1.1.1, Attachment 1)

On May 15, 1987 the Commission issued Order No. G-24-87, which noted that Rate Schedules 1105 and 1205 would remain unchanged until April 1,1991; found that the introduction of the proposed electric service was in the public interest; and approved the introduction of Rate Schedules 1105, 1205 and 1805 (Exhibit B-8, EPG 1.1.24, Attachment 1).

BC Hydro provided copies of the Residential Dual Fuel Interruptible Electric Service Agreement and the General Service Dual Fuel Interruptible Electric Service Agreement (Exhibit B-3, BCUC 1.41.2, Attachments 1 and 2). Both are short documents containing 12 clauses to which Rate Schedule 1105 or 1205 would have been attached upon execution. BC Hydro notes that like all other Terms and Conditions of BC Hydro's service, this agreement is subject to Commission jurisdiction (Exhibit B-3, BCUC 1.41.2). BC Hydro states that it does not believe the E-Plus agreement was ever filed as a tariff document with the Commission. While the agreement could have been filed as a tariff supplement, BC Hydro does not believe that it was lawfully obliged to do so (Exhibit B-7, BCUC 2.95.1).

In 1990 the E-Plus Rate Schedules were closed. BC Hydro cites the two main reasons:

- the expected supply of surplus energy was diminishing, and there was no longer value in selling energy at a discounted rate; and
- a gas pipeline to Vancouver Island had been approved that would provide an additional heating option to one of the key targeted areas for this rate.(Exhibit B-1, pp. 41-2)

On October 17, 1990 Mr. Sheehan, then BC Hydro's Vice-President, Customer Services wrote to the approximately 15,000 E-Plus customers to advise them that BC Hydro was planning to apply to the Commission to increase the E-Plus rate from 2.5 cents/kWh (where it had remained unchanged since May 1987) to approximately 3.3 cents/kWh. The letter outlined some options for E-Plus customers including switching to natural gas as it became available, or switching to regular electricity service. The third from last paragraph of the letter states: "*Electric Plus is a very specialized product for a very specialized type of customer*. To our customers who have confidence in their back-up system, Electric Plus offers true value for their heating dollar" (emphasis in original) (Exhibit B-3, ESVI 1.2.5, Attachment 1).

On January 7, 1991 Mr. Sheehan wrote another letter to BC Hydro's E-Plus customers. The letter includes the following paragraph:

> "We had previously indicated when the program was introduced in 1987 that the Electric Plus rate would be fixed until at least 31 March 1991 and thereafter the rate WOULD NEVER EXCEED two thirds of the regular price of electricity. Naturally, WE STAND BY THAT COMMITMENT" (emphasis in original).

The letter went on to say that based on the responses BC Hydro had received from its E-Plus customers, it had decided to delay any action with respect to the rates pending further communication with customers and the Commission.

The letter also commented on BC Hydro's intention to explore options with the Commission and BC Hydro's customers to see how the Electric Plus program could be best administered, and to deal with specific situations such as the upcoming gas supply to Vancouver Island, the Sunshine Coast and

Squamish. In response to a question from Commission Counsel on what B C Hydro did to explore those options, BC Hydro filed Exhibit B-53, which attached Commission Order No. G-21-92, dated February 13, 1992. That Order refers to an application to amend the Electric Plus rate schedules, which according to Recital A of the Order, was filed on December, 18, 1991.

Recital B of Order No. G-21-92 states that BC Hydro sought Commission approval to delete the following items from Rate Schedule 1105:

- the requirement that the availability of service be contingent upon there being no natural gas service to customer's premises;
- the requirement for a fuel storage facility on the customer's premises; and
- the reference to specifically named fuels to be used for the backup heating system.

The Commission noted in Recital C of the Order that Centra Gas British Columbia Inc. had advised BC Hydro that such changes to the Electric Plus program would allow it to supply natural gas distribution service to those markets (Exhibit B-53). According to Recital D of the Order the Commission found the amendments "necessary and in the public interest" and approved the BC Hydro application.

In its September 8, 2003 Decision on BC Hydro's Vancouver Island Generating Plant ("VIGP") application, the Commission considered the E-Plus program and noted that:

> "The Commission Panel is aware that the conditions which led to the creation of E-Plus have not existed for many years. If BC Hydro cannot reliably count on E-Plus customers shifting to alternative heating sources at peak times when it will benefit the system, then there may no longer be appropriate conditions to justify the discount rate offered to E-Plus customers. In that instance, BC Hydro may wish to apply for a phase out of the tariff schedule or to amend the rules for curtailment to ensure customers shift to alternative heat sources when necessary. The Commission would then establish a process to allow E-Plus customers to provide input on the application prior to any determination. BC Hydro may consider this issue as part of its 2004 revenue requirements application" (Exhibit B-3 ESVI IR 14.1, VIGP Decision, p. 22; BC Hydro Final Argument, pp. 6-7).

4.2.3 Customer Data

BC Hydro states that the number of Residential customers currently taking service under the E-Plus Rate Schedules is as follows:

Table 4-4

Region	**Number**	**Percentage**
Vancouver Island	8,865	70%
Northern	517	4%
Lower Mainland	1,124	9%
Interior	2,244	18%
Total	12,750	100%

Source: Exhibit B-33

and that it provides the service to approximately 159 General Service accounts as well (Exhibit B-1, p. 48, Figure 9).

BC Hydro estimates that its Residential accounts consume approximately 140 GW.h per year (88 GW.h in the winter season) on their E-Plus meters, with each residential customer consuming approximately 12,000 kW.h per year. Its 159 General Service customers consume approximately 41.3 GW.h per year (Exhibit B-1, Appendix C Schedule 7.0; Exhibit B-8, E-Plus Group 1.5.3). BC Hydro provided a distribution of annual consumption for the year ended September 30, 2006 of a sample of 11,780 E-Plus customers on both their E-Plus meter and their residential service meter:

Table 4-5

Annual Consumption Range (kW.h)	E-Plus Meter	Residential Meter	Both Meters	Percentage of Customers
0-2,500	823	215	22	0.2%
2,500-5,000	1,126	864	56	0.5%
5,000-7,500	1,479	1,617	161	1.4%
7,500-10,000	1,812	2,130	363	3.1%
10,000-12,500	1,786	1,937	598	5.1%
12,500-15,000	1,448	1,600	819	6.9%
15,000-17,500	1,068	1,177	1,102	9.4%
17,500-20,000	763	764	1,210	10.3%
20,000-22,500	509	530	1,275	10.8%
11,500-25,000	311	304	1,224	10.4%
25,000+	655	642	4,950	42.1%
	11,780	11,780	11,780	100.0%

(Derived from Exhibit B-8, EPG 1.5.4)

BC Hydro testified “So if you start to compare apples to apples, there is a little bit of evidence that suggests perhaps they are using more electricity than other electrically heated homes” (T7:1074).

BC Hydro states that it only has information readily available concerning the backup heating types used by approximately 65 percent of the residential E-Plus accounts, which indicates that 75 percent use wood, 19 percent use oil and 6 percent use propane (Exhibit B-8, EPG 1.3.16).

BC Hydro’s current rates for the E-Plus Rate Schedules are as follows:

Table 4-6

Rate Schedule	Cents per kW.h First Block	Cents per kW.h Second Block	Threshold of Second Block
1105	3.35	n/a	n/a
1205	3.35	2.20	8,000 kW.h/month
1206	3.35	2.20	8,000 kW.h/month
1207	3.35	2.20	8,000 kW.h/month

Source: Exhibit B-1, Appendix C, Schedule 7.0; Exhibit B-3, ESVI 1.2.5, Attachment 3

BC Hydro's present tariff states that if during a Period of Interruption a customer has failed to comply with its requirement to cease the use of electricity and it continues to supply electricity, the customer shall pay a penalty rate for such electricity of 19.55 cents per kW.h.

4.2.4 BC Hydro's Proposal

BC Hydro characterizes its proposal with respect to E-Plus rates as being to phase them out over a 10-year period ending April 1, 2018.

In addition, it proposes to eliminate all the special conditions contained in Rates Schedules 1105, 1205, 1206 and 1207 effective April 2008, notably the requirements for its E-Plus customers to maintain a backup heating system in working order and its right to interrupt the supply "…whenever there is a lack of surplus hydro energy and the service cannot be provided economically from other energy sources" (Exhibit B-3, CEC 1.15.3). It proposes to add one condition restricting the ability to transfer the E-Plus rate to a new customer by amending the Availability Clause to state that the Rate Schedule is available "only in Premises where there has been no change in customer since April 1, 2008" (Exhibit B-1, Appendix D, p. 3).

4.2.4.1 BC Hydro's Rationale

BC Hydro states that E-Plus rates do not recover the cost of service and that other customers within the associated rate classes subsidize E-Plus customers. BC Hydro further submits that "… this does not support the principle of fairness" and that "… in an environment of rising marginal energy costs, E-Plus rates do not align with the need to encourage conservation within B.C.” (Exhibit B-1, p. 42).

(i) Fairness

BC Hydro states that the R/C ratios are approximately 74 percent and 84 percent for E-Plus residential and commercial customers respectively when combining both the main and E-Plus accounts and when demand-related transmission and generation costs are allocated on a 12 CP basis (Exhibit B-3, BCUC 1.43.8). BC Hydro further states that under a 1 CP classification of generation and transmission demand-related costs, the R/C ratio for residential E-Plus load would be 50 percent, whereas assuming that this load attracts no generation or transmission demand-related costs because the load is interruptible, the R/C ratio “climbs to approximately 71%” (Exhibit B-61).

BC Hydro testified that the FACOS did not include E-Plus as a separate sub-class and that the cost to serve residential customers, whether they are E-Plus or not, is the same since they receive the same service from BC Hydro, have the same access to the call centre, and use the same billing system. While E-Plus customers are planned as a firm load and the cost to serve E-Plus is the same as other residential customers, the revenue BC Hydro receives is different (T7: 1055-1056; T6: 967). On whether previous cost of service studies had been carried out for the E-Plus service, BC Hydro provided the following evidence:

> COMMISSIONER MILBOURNE: “At the time the program was applied for and approved by the Commission, was there a cost of service based revenue-to-cost ratio established for it at the time, and was that part of the application?
>
> MS. ZACHARIAS: A: Not that we know of.
>
> COMMISSIONER MILBOURNE: Thank you. Would you agree with me that if the test that B.C. Hydro is applying today to establish that the rate does not recover its cost of service had been done at that time, on the same basis, that it would show a deficit in terms of cost of service recovery vis-à-vis non-E-Plus customers, as it does today?
>
> MS. ZACHARIAS: A: So I think that's true. If part of your assumption is that if the revenue-to-cost ratio at that time had been done with the assumption of firm energy, it would have been a revenue-to-cost ratio that would have been less than 100.” (T8:1249-50)

The E-Plus Group submits that the physical infrastructure required to serve its customers is no different today than it was 20 years ago and any increases in operating costs have been passed on to its customers at the same rate as they have been passed on to other rate classes which demonstrates that the additional costs of serving its customers are still being covered. Furthermore, it submits that even if the Commission does not accept its evidence and argument on that point, BC Hydro has adduced no evidence as to what the E-Plus cost of service is (E-Plus Group Argument, p. 3).

The E-Plus Group submitted that the revenue from the E-Plus Rate Schedules should be treated as trade revenue in the FACOS:

> "… And it seems almost certain that in 1987 the EP [E-Plus] revenue was viewed in the nature of trade revenue and therefore included in the calculation of the revenue requirement, not in the denominator of the cost of service calculation. BC H[ydro] has adduced no evidence in this Application that would counter that characterization of the original Order nor has it shown why EP sales should not remain in the numerator of the cost of service calculation.
>
> BC Hydro is now saying is that its cost of acquiring power has increased and so EP customers should be counted once in the denominator as Class 1101 customers and placed in the denominator a second time for their EP consumption" (E-Plus Group Argument, p. 4).

According to the E-Plus Group, the E-Plus contracts are energy sales contracts in the guise of a rate schedule. As such, they should be given the same accounting treatment that Powerex sales of BC Hydro surplus receive as there is no cost of service allocated to those energy sales. Those sales are deemed to be trade revenues that serve to reduce BC Hydro's annual revenue requirement. The E-Plus Group submits: "The thing that has brought up the E-Plus contracts is that the opportunity cost of that power went from near zero in 1987 to a very high figure today" (E-Plus Group Argument, p. 4).

In its Reply BC Hydro submits that a central premise of the E-Plus Group is that BC Hydro has failed to demonstrate that E-Plus customers, if considered as a notional rate class for cost of service purposes, have a revenue-to-cost ratio less than other residential or small commercial customers.

BC Hydro further submits that BC Hydro witnesses testified that there is no difference in those costs between E-Plus and other residential customers. In BC Hydro's submission unless the E-Plus Group can point to some contrary evidence, or impeach the credibility of those witnesses, the Commission has no basis to not accept that evidence. BC Hydro does agree that it bears the burden of proof on the proposed phase-out of E-Plus service, on a balance of probabilities, and submits that it has done so (BC Hydro Reply, pp. 28-29).

(ii) Change in Circumstances

BC Hydro states that in the 1980's, it had a significant surplus in both energy and capacity, but that the Pacific Northwest also had a significant surplus, and access to export markets from B.C. was not sufficiently developed to allow it to sell surplus energy economically, nor were there robust real-time markets. This was the contextual background for the development of E-Plus rates. Since that time, load growth has continued and BC Hydro has become a net importer of energy (with load growth running at approximately 2 percent per year). Additionally, there are now robust real-time electricity markets in the Pacific Northwest and open access transmission tariffs have made those markets available to BC Hydro. Therefore, according to BC Hydro, the original premise of the E-Plus rate has been rendered obsolete by changes in BC Hydro's supply and demand situation and the industry structure (Exhibit B-7-1, BCUC 2.111.1).

When asked by the E-Plus Group to confirm whether or not it has at least 182 GW.h (the annual E-Plus residential and general service consumption) of non-firm or interruptible energy from time to time, BC Hydro stated that it does not have non-firm or interruptible energy available "from time to time", and that due to its storage capability, the availability of surplus energy is properly measured over a long period of time, such as a year. BC Hydro has been a net importer of energy for the last five years (Exhibit B-69).

In a speech given in May 2007, BC Hydro's Chief Executive Officer stated:

> "We will continue to trade with our neighbours, as we have for many years.
>
> Our consumption is greatest in the winter and California's in the summer.

> So long as there is the right investment in Transmission, we can continue to build on the opportunities for seasonal exchange" (Exhibit C7-12, p. 5).

BC Hydro submits that its supply portfolio in 1987 justified the creation of the program, while the current supply portfolio does not, and that indeed justifies the elimination of the service. In 1987 BC Hydro was able to meet all its service obligations through the delivery of energy generated at its own hydro facilities. Moreover, it had more water (energy) in its reservoirs in a given year than it required to meet those obligations. The economic equation that resulted from those circumstances was that the marginal cost of supply was very low (water rentals only), and an opportunity cost was incurred whenever water (energy) in the reservoirs was spilled for lack of a market. According to BC Hydro most of these key circumstances that justified the provision of E-Plus Service no longer exist. In particular, BC Hydro has been a net importer of energy for several years; the marginal cost of supply is now much higher than the E-Plus rate; and the evolution of wholesale markets has led to more alternatives to spilling (BC Hydro Argument, pp. 52-53).

The E-Plus Group rejects the idea that BC Hydro is a net importer of energy. The E-Plus Group submits that "the oft-repeated phrase that BC Hydro is a "net importer" is a convenient characterization that does not stand up to an analysis of whether the BC Hydro system has 182 GWh of non-firm surplus from time to time", and that a hydro-dominated system that calculates firm energy based on back to back dry years must have non-firm surplus whenever reservoir inflows exceed the conservative firm energy estimate of the utility. The E-Plus Group characterizes the underlying problem to be the considerable competition for "that surplus" that exists today, whereas in 1987 it was "difficult to give it away". The E-Plus Group submits that the 2007 Energy Policy is trying to establish energy security and self-sufficiency for British Columbia which will "in future lead to a situation where non-firm surplus is more plentiful than it is today" (E-Plus Group Argument, p. 6).

(iii) The Need to Encourage Conservation

BC Hydro testified that, initially, removing the misalignment between a discounted rate and the overall conservation message was a primary consideration with respect to conservation. The driver initially was not conservation or to get to conservation through fuel switching, but were fairness and removing the "misalignment around messages". The initial driver appears to have become less important to BC Hydro, for as Ms. Zacharias commented: "But now that we start to get into looking at exactly what the situation is, there may be that we can encourage some of these customers to think twice about how they are using their electric heating and use it in a more efficient way" (T7:1073, 1075).

The E-Plus Group submits that the evidence is that many E-Plus customers, especially those with electric baseboard heating, have no way to respond to an increase in price by fuel switching and that BC Hydro "admits that it has provided no evidence that an increase in EP rates will generate a significant conservation response". The E-Plus Group submits that the price signal argument provides no support for BC Hydro's application to eliminate the E-Plus program and "should not have been included in the first place because conservation really plays no part in the allocation of the cost of service among rate classes" (E-Plus Group Argument, p. 8).

4.2.4.2 Interruption of E-Plus Customers

BC Hydro's Rate Schedule 1105 currently states that "The Authority may, at any time and from time to time, interrupt the supply of electricity under this rate schedule whenever there is a lack of surplus hydro energy and the service cannot be provided economically from other energy sources". BC Hydro states that there is no provision in the current tariff that allows it to interrupt E-Plus customers to relieve transmission constraints and there is no practical way to interrupt E-Plus customers during the periods of short duration when its system is typically constrained. BC Hydro states that interrupting its E-Plus customers "is of little value to BC Hydro or ratepayers given the challenges of coordination. The E-Plus customers have never been interrupted" (Exhibit B-1, p. 42).

BC Hydro also states that the expression “lack of surplus hydro energy” is not precisely defined in its tariff nor in its communications material distributed and that it is at least arguable that it refers to those periods during which BC Hydro has been a net importer of electricity (net imports were approximately 900 GWh in F2003; 5,300 GWh in F2004 and 6,900 GWh in F2005), and it may well have been lawful for BC Hydro to interrupt E-Plus customers since that time. BC Hydro acknowledges that the conditions under which it may have interrupted E-Plus customers have not been certain (Exhibit B-3, Rochon 1.2).

BC Hydro testified that “… since we’re a net importer, we could potentially, under the way that the tariff is written, interrupt them continuously, which would be the same thing as phasing out the E-Plus rate. We didn’t think that that was the best option in this circumstance, that a better option would be to phase it out over time” (T6:1000).

There are no means for interrupting E-Plus service by remote automatic means. E-Plus service can be interrupted manually by personnel going to the premises and switching off the E-Plus circuit and if BC Hydro manually interrupts the service there is no requirement for written notice. Alternatively, BC Hydro can provide written notice requiring customers to interrupt their electricity supply by shutting off the circuit breaker for their E-Plus service. The notice would specify the dates and times of interruption. BC Hydro notes the impact of such interruption could only be measured between consecutive meter readings (Exhibit B-3, ESVI 1.3.2).

BC Hydro states that it has considered whether shorter periods of interruption would be possible and of value in the context of how its system operates, but that it has several options at its disposal to manage short term system constraints that would be more practicable to interrupting E-Plus customers, including the ability to purchase electricity from Powerex (market purchases, including Canadian Entitlement); to operate the Burrard Thermal generating station or initiate voluntary customer curtailment, all of which provide quick responses and a high degree of reliability required to address a short term supply shortage. BC Hydro states that curtailment of E-Plus customers involves a longer notice and activation period before the beneficial relief is experienced and therefore would provide no value for short term, real-time needs.

BC Hydro also states that if supply shortages for serving domestic load caused it to interrupt its E-Plus customers, the interruption would need to be for several months duration during the winter season (November to February) when the system experiences its peak demand load and when the E-Plus load is highest (roughly 88 GW.h for the 2005/2006 winter season).

BC Hydro further states that winter-season interruption may be of some value to its long-term supply and capacity management planning, provided its customers actually curtail. BC Hydro believes it is unrealistic to assume that all customers would curtail and that it is difficult to estimate what portion of E-Plus customers would actually curtail in the event of an interruption. At least one interruption period would be required to observe and establish the behaviour pattern of E-Plus customers before any meaningful and useful data would be available for incorporation in BC Hydro’s long-term load forecasting, planning, decision and system management operational process. BC Hydro estimates the cost of interrupting E-Plus customers to be roughly $1.4 million if regular reading schedules were used and $1.8 million if special reading schedules were used. BC Hydro estimates using the E-Plus 2005/06 winter consumption of 88 GW.h as a point of reference, the value of a 25 percent reduction in energy use resulting from customer curtailment to be $1 million and the value of a 50 percent energy use reduction at $2 million. BC Hydro acknowledges a gap between energy supply and demand, and that interrupting E-Plus customers for an extended period of time would, in theory, provide some marginal benefit but states that it has other options available to meet the supply shortage that are economic, more practical, less problematic and not as disruptive to customers. BC Hydro believes it should exercise those options first and not use extended interruptions of customers to meet supply gap issues (Exhibit B-7-1, BCUC 2.111.1).

BC Hydro submits that one alternative to the phasing-out of E-Plus service that may have “superficial appeal” is to start interrupting E-Plus customers over the winter months which would be consistent with the terms and conditions of the E-Plus rate. However, BC Hydro believes this alternative would be unacceptable, in light of almost 20 years without an interruption of E-Plus customers. It will not voluntarily cut off residential heating load in the winter after 20 years of not doing so, without making every effort to ensure that there will be no customer who suffers irreparable harm from such a measure (BC Hydro Argument, p. 54).

The E-Plus Group submits that in contract law it is not a relevant consideration if BC Hydro has no practical way of interrupting E-Plus customers, and as a result its contracts with them have turned into “bad bargains from BCH’s perspective” ….. “A bargain is a bargain, particularly where the party complaining is the far more sophisticated party and the one that ought to have realized at the outset that they had no way of interrupting EP customers” (E-Plus Group Argument, p. 8).

4.2.4.3 Transition

BC Hydro states that by commencing the changes on April 1, 2008, its E-Plus customers will have time to determine their best course of action for the proposed rate changes in the short term and for the eventual elimination of the E-Plus rates in ten years, as well as the opportunity to participate in Power Smart programs to increase their energy efficiency and thereby reduce the impact of the changes to the E-Plus rates (Exhibit B-1, p. 43).

BC Hydro conducted stakeholder discussions prior to filing its Application. In the case of E-Plus Customers, it stated that the feedback indicated that many felt BC Hydro had made a permanent commitment; that capital investments had been made to qualify for the rate; that recent investments had been made to maintain back-up systems (a condition of the rate); that purchasing decisions had been based on the fact that the premise had the E-Plus rate; that if the E-Plus rate was to be changed, it should be done with a phased approach; and that adequate notification be given to allow customers time to respond to the change and allow further opportunity to recover investments made. BC Hydro considered phase-out periods of three, four, and five years for E-Plus rates. Its 2007 RDA proposal is to increase the rate to two-thirds the standard rate over a five year period and eliminate the rate following a 10 year notification period. The proposal to terminate the requirement to maintain backup heating systems and eliminate the transfer of the rate for new customers has not changed from the original proposal (Exhibit B-3, CEC 1.5.1).

<u>Impact of the Transition Proposals</u>

BC Hydro calculates the annual percent increase for each of the E-Plus Rate Schedules as follows:

Table 4-7

Percent Increase from Phase-Out of E-Plus Rates

April 1st	1105	1205	1206	1207
2008	6.6	8.6	8.5	10.2
2009	4.3	8.5	8.5	9.7
2010	4.2	9.4	7.9	8.9
2011	4.0	8.6	8.1	9.1
2012	3.8	7.9	8.3	9.3
2018	48.1	46.3	45.9	45.9

(Derived from Exhibit B-1, Appendix C, Schedule 7.0)

The impact of these increases on an average residential customer who uses 12,000 kW.h per year on the E-Plus meter is approximately $25.00 per year until April 1, 2018 when the rate increases by 48 percent (or approximately $240.00). BC Hydro calculates the impact on its 159 E-Plus General Service customers stating that the average annual net bill impact on General Service E-Plus customers (considering both meters) for the first five years would be 1.8 percent (Exhibit B-1, p. 47).

The CEC submitted it "… believes that BC Hydro has dealt with E-Plus customers in a fair and reasonable way and that the proposal of BC Hydro attempts to provide a huge amount of respect for the historical circumstances which resulted in the E-Plus rates, while trying to move towards an appropriate foundation and should be given due consideration for approval by the Commission (CEC Argument, p. 11).

In Argument BC Hydro submits that is not a question of whether, but how, E-Plus service ought to be terminated and that on this question it has had regard to a number of conflicting factors. Uppermost in BC Hydro's thinking was the prospect of E-Plus customers having made investments in their back-up heating systems that would not be recouped with a speedy phase-out of the service. This concern was expressed to BC Hydro during its stakeholder consultation and caused BC Hydro to extend the phase-out period from 5 to 10 years (BC Hydro Argument, pp. 53-54)

4.2.4.4 Investment, Savings and Return on Investment

BC Hydro calculates that based on an average annual consumption of 12,000 kWh on the E-Plus meter an E-Plus customer who signed up for the rate in April 1988 would have saved $6,410 over the 20 year period ending March 31, 2007 compared to taking power for home heating on BC Hydro's residential rate (Exhibit B-3, BCUC 1.41.4). BC Hydro states that the annual savings in constant 1987 dollars is $4,920 and that the Present Value of the savings in 1987$ is $2,934 which, based on a conversion cost of between $1,300 and $2,800, suggests that the discounted payback period would be between 6 and 18 years (Exhibit B-7, BCUC 2.96.1).

However, BC Hydro did not track the investments or savings of individual E-Plus customers:

> MR. CAIRNS: Q: And what you were able to ascertain, B.C. Hydro doesn't have any information about how much E-Plus customers initially invested, do they?
>
> MS. ZACHARIAS: A: We do not know how much each of the 13,000 customers invested.
>
> MR. CAIRNS: Q: You do not know how much they spent to operate, maintain and refurbish their back-up heating systems?
>
> MS. ZACHARIAS: A: We do not know that.
>
> MR. CAIRNS: Q: You do not know -- you did not track and don't know the amounts, if any, that E-Plus customers may have saved over alternative heating costs, correct?
>
> MS. ZACHARIAS: A: No we do not" (T7:1092)

Terasen estimates that the savings for E-Plus customers compared to propane at Revelstoke and to furnace oil on Vancouver Island in the years 1994 to 2007 would have been in the order of $2,123 and $3,309 respectively (Exhibit C7-24).

The E-Plus Group states that the calculation of savings achieved by E-Plus customers using regular rates minus E-Plus rates multiplied by consumption is incorrect since it ignores the fact that E-Plus customers would have had to pay something for combustion fuels and that E-Plus was sold as a way to save over the cost of combustion fuels, not over the cost of regular power rates. The savings are the difference between the E-Plus bills and the avoided combustion fuel bills. The E-Plus Group states that once payback has been achieved it would be wrong to assume that the stream of E-Plus savings or returns on investment can be turned off by regulatory intervention without any harm to the initial investors who, although they might have received the return of their capital will not have realized any return on their capital. The E-Plus Group states that BC Hydro does not know how much money E-Plus customers invested in backup equipment and that its assumption that the average E-Plus customer initially invested $1,300 to $2,800 has created a model for which there is no factual foundation (Exhibit C8-7, BCUC 1.4.1).

In its submissions, the E-Plus Group refers to BC Hydro’s evidence that it has no record of how much E-Plus customers invested in their backup heating systems; what it cost them to operate and maintain their systems; what the “savings” over other fuels might have been; or what actual rates of return (positive or negative) E-Plus customers have achieved since inception of the program. In the result, it submits that BC Hydro’s position on these issues is without substance (E-Plus Group Argument, p. 8).

4.2.4.5 Attrition

BC Hydro calculates that the introduction of a restriction on transferring the service to a new customer would cause the number of E-Plus residential customers to reduce by approximately 8 percent per year, so that by 2018 there would only be 5,000 remaining (Exhibit B-3, ESVI 1.1.12, BCUC 1.42.1). In his Opening Statement counsel for the E-Plus Group submitted that since “… attrition … will ensure that about 80 percent of this entire sub-class will disappear…” that the

Commission should "let the E-Plus program die a natural death and not accede to [BC] Hydro's request to accelerate its demise" (T3:345-346).

No Intervenor took exception to BC Hydro's proposal to restrict future transfers of the service.

4.2.4.6 Jurisdictional Matters – E-Plus Group Argument

In respect to jurisdictional matters, the only Intervenor to submit argument about BC Hydro's proposal for the E-Plus rates is the E-Plus Group, which submits that the Commission has been asked to approve the abrogation of approximately 12,000 bilateral contracts. The summary of its Argument on this point, found at page 8 of the E-Plus Argument, is that the Commission lacks the power and jurisdiction to make the order sought because BC Hydro has invoked the wrong procedure
(E-Plus Group Argument, pp. 8-9).

The E-Plus Group submits that the Commission's power over contracts between BC Hydro and third parties is limited to the power outlined in section 64 of the UCA, which states:

> "
> **Orders respecting contracts**
>
> **64** (1) If the commission, after a hearing, finds that under a contract entered into by a public utility a person receives a regulated service at rates that are unduly preferential or discriminatory, the commission may
>
> (a) declare the contract unenforceable, either wholly or to the extent the commission considers proper, and the contract is then unenforceable to the extent specified, or
>
> (b) make any other order it considers advisable in the circumstances.
>
> (2) If a contract is declared unenforceable either wholly or in part, the commission may order that rights accrued before the date of the order be preserved, and those rights may then be enforced as fully as if no proceedings had been taken under this section".

The E-Plus Group submits that BC Hydro's 2007 RDA does not seek a Commission order under section 64 of the UCA to declare the EP contracts unenforceable on the basis that they are unduly preferential; and that the regulatory review of the RDA cannot be considered to have been a hearing that raised that specific issue and gave the parties an opportunity to be properly notified that "unduly preferential" was going to be an issue so as to prepare and advance their cases and to cross examine on that specific issue.

The E-Plus Group submits that, absent a specific request for a consideration and hearing under section 64, the UCA contains no other provision that empowers the Commission either to order the abrogation of the E-Plus contracts or to absolve BC Hydro of the consequences of breaching the E-Plus contracts, and that such an order could invite litigation in a '… thorny area where the general law of contract and the law of utilities regulation intersect. In other words, granting the order would naturally lead one to pose the questions "What is the law in cases where BC Hydro signs contracts that do not explicitly give BC Hydro or the Commission the power to unilaterally terminate or alter their terms and conditions?" and "Does the Commission have the power in such cases to abrogate those contracts?"' (E-Plus Group Argument, p. 10).

As an alternative, the E-Plus Group submits that "Even if the Application has properly invoked section 64 or if the Commission is of the view that it nonetheless has the power to make an order abrogating the EP contracts, the onus is on BC Hydro to provide a compelling evidentiary case for terminating those contracts. BC Hydro has fallen far short of providing such evidence and this has been explained above where each pillar of BC Hydro's argument was analyzed" (E-Plus Group Argument, p. 12).

The E-Plus Group agrees that BC Hydro can raise their rates within certain limits without abrogating the E-Plus contracts and eliminating the program (E-Plus Group Argument, p. 13).

The E-Plus Group submits that the key terms of the E-Plus contracts are:

i. E-Plus was a permanent program;

ii. they do not contain a clause granting BC Hydro or the Commission the power to abrogate them or unilaterally alter their terms;

iii. the price would never exceed two thirds of the "regular rate"; and

iv. sales of surplus to others would be cut off before sales to E-Plus customers would be cut off.

For items (i) and (iv) above the E-Plus Group relies on a BC Hydro promotional brochure, which stated at page 42 "Residential (sc. E-Plus) customers will be given priority over other surplus electricity customers and <u>will not be interrupted to export surplus interruptible energy</u>. Electric Plus is <u>a permanent program</u>, but the number of customers on the special rate will be limited to match the amount of surplus available. This will ensure that each Electric Plus customer gets enough low-cost energy to repay conversion costs and keep saving year after year" (underlining in original) (Exhibit C8-4).

For item (ii) the E-Plus Group relies on the Agreements themselves.

For item (iii) the E-Plus Group relies on the wording in Mr. Sheehan's letter dated January 7, 1991 referred to in section 4.2.2 in which Mr. Sheehan, then BC Hydro's Vice President of Customer Service, stated that "and thereafter the rate WOULD NEVER EXCEED two thirds of the regular price of electricity. Naturally, WE STAND BY THAT COMMITMENT." [Emphasis in original]

4.2.4.7 BC Hydro Reply

In its Reply BC Hydro submits that the E-Plus Group's central premise is that E-Plus service is afforded to BC Hydro customers not under a rate established pursuant to the UCA, but under a private contract that is not subject to the Commission's rate-setting powers or jurisdiction except, perhaps, section 64 of the UCA. BC Hydro responds that sections 61(3) and 64 of the UCA make it clear that it is unlawful for a public utility to charge rates for public utility services that have not been filed in accordance with the UCA, and that its original application for E-Plus service and the Commission's order approving that application make it certain that BC Hydro at all times considered the E-Plus service to be a service subject to these provisions of the UCA and, by extension, subject to amendment by Commission order under section 58 of the UCA.

According to BC Hydro, the E-plus rates, and the schedules which prescribe those rates, have been amended every time there has been a general rate increase, and was specifically amended in 1992 to allow for, among other things, natural gas to be the back-up heating fuel. Further, the materials provided to E-Plus customers make it clear that BC Hydro communicated the fact of Commission jurisdiction over the E-Plus service and rates to its customers on more than one occasion. To suggest as the E-Plus Group now does that their service was only ever provided under a private contract ignores the unequivocal history of the service. As to the E-Plus Group claim that it is provided service under private contracts, BC Hydro submits that the E-Plus Group did not prove those contracts in this proceeding and that the form of agreement said by the E-Plus Group to establish a private, legally binding agreement refers specifically to the service being provided in accordance with BC Hydro’s tariff and rate schedules, supporting BC Hydro’s submissions above.

On the possibility of lawsuits against BC Hydro if the service is terminated by the Commission, or of members of the E-Plus Group trying to prove independent contracts with BC Hydro in the event the Commission approves the phase-out of the service as proposed by BC Hydro, or otherwise, BC Hydro submits that the Commission should be cautious in making any findings regarding whether there private contracts exist between BC Hydro and E-Plus members (BC Hydro Reply, pp. 26-28).

Commission Determination

The Commission Panel has considered the arguments concerning the Commission’s jurisdiction over the E-Plus rates. The Commission Panel is not persuaded by the E-Plus Group’s argument that its members have “contracts” with BC Hydro that the Commission has limited jurisdiction to abrogate, or that those contracts are everlasting in nature with a guaranteed price cap. Commission Orders No. G-24-87 and No. G-21-92 do not reference “contracts.” They do reflect the application of the Commission’s statutory jurisdiction over rates. Section 59(4) of the UCA makes it clear that it is a question of fact, of which the Commission is sole judge as to whether a rate is unjust, unreasonable or unduly discriminatory. The Commission Panel agrees with BC Hydro that section 64 of the UCA does not apply in a situation where service has been provided from the outset under rate schedules filed in accordance with the UCA. The Commission Panel will make no findings as to the nature of the commercial relationship that may exist between BC Hydro and its E-Plus customers.

The Commission Panel is of the opinion that it had the jurisdiction to find Rate Schedules 1105 and 1205 to be in the public interest in 1987, to amend them in the public interest in 1992, and that that jurisdiction remains.

The Commission Panel has considered the E-Plus Group's submission that "the E-Plus was a permanent program" and finds that, while the Residential and General Service Dual Fuel Interruptible Electric Service Agreements have no specific termination date, the Rate Schedules themselves are subject to Commission jurisdiction and as such cannot be everlasting. **The Commission Panel has also considered the E-Plus Group's submission that the price would never exceed two thirds of the "regular rate" and finds that this statement was made to the E-Plus customers in a letter from BC Hydro and that such a communication cannot bind the Commission.** Pursuant to the statutory powers given to it under the UCA, it is for the Commission, and not for a public utility and its customers, to determine rates that are just, reasonable and not unduly discriminatory.

The Commission Panel has also considered the evidence and submissions concerning the E-Plus customers' investment in backup facilities and whether they have earned a return on and of that investment. Although the Commission Panel finds the evidence inconclusive, the Commission Panel does not find the question to be determinative, as the Rate Schedules before the Commission have never made reference to the customers' investment or their need to earn a return on and of it. If it remains an issue, it is a commercial issue between BC Hydro and its E-Plus customers which is more appropriate for determination by the Courts, if necessary.

The Commission Panel will now consider BC Hydro's proposal for the E-Plus rates. In exercising its jurisdiction to consider rate design proposals, the Commission must consider the public interest (BC Hydro Reply, Attachment A, BCUC Decision on BCTC Application for an Open Access Transmission Tariff, June 20, 2005 p. 10).

The Commission Panel rejects BC Hydro's characterization of its proposal as "phasing out" the E-Plus Rate Schedules. The Commission Panel considers that BC Hydro's Application to be to terminate the E-Plus Rate Schedules with a proposal for transition and mitigation. The Commission Panel will first of all determine if the Application for termination is in the public interest and will proceed to consider BC Hydro's proposal for transition and mitigation.

The Commission Panel is of the opinion that in order to meet the standard of being in the public interest a Rate Schedule must be just, reasonable and not unduly discriminatory. In doing so one of the factors it may consider is whether the circumstances that made it in the public interest in 1987 have changed such that the original intent of the Rate Schedules has been frustrated.

The Commission Panel believes that BC Hydro should have anticipated vigorous opposition to its proposal for the E-Plus rates, and should have presented specific evidence as to the cost of providing service to the E-Plus meter. BC Hydro has noted that it bears the burden of proof on its proposed phase–out of E-Plus service.

The E-Plus program was designed to market surplus electricity (BCUC 1.41.1) and that in the absence of markets for that surplus energy "… the extra water [that would otherwise be used to generate energy] would be spilled" (Exhibit B-3, ESVI 1.2.5, Attachment 1).

The Commission Panel finds that the evidence before it fails to demonstrate that the E-Plus rates no longer exceed the low short-run marginal energy costs that would exist in a period of surplus energy or no longer make any contribution to offsetting the fixed costs of BC Hydro. While there is little doubt that the incremental revenues from E-plus sales versus opportunistic exports of energy has been reduced BC Hydro provided no quantifiable evidence as to the degree of that reduction.

The Commission Panel finds no merit in the E-Plus Group's argument that E-Plus revenue should be shown as an offset to power costs, rather than revenue. If E-Plus sales revenues are treated for accounting purposes in the same manner as Powerex sales of BC Hydro surplus, and those sales are deemed to be trade revenue that reduce the E-Plus revenue requirement, rather than as revenue from customer rates, then the concept of a R/C ratio for service to the E-Plus meter has no useful meaning. Considering the E-plus meter as a customer class, but treating the revenues from E-Plus as an offset to power supply costs, would mean that the "R" in the R/C ratio is zero, and hence the R/C ratio for the E-plus meter sub class would be zero.

The Commission Panel finds that BC Hydro has failed to meet the burden of proof that its E-Plus Rate is no longer in the public interest or otherwise just and reasonable. So far as changes in circumstances are concerned, the Commission Panel is cognizant of a number of changes since the Rate Schedule was introduced in 1987. The Commission Panel accepts BC Hydro's assertion that it is a net importer of electricity and from this assertion draws the inference that BC Hydro no longer has available to it a surplus of hydro energy at all times. The evidence before the Commission Panel concerning how often during the course of a year such a condition existed was insufficient to enable the Commission Panel to determine the extent to which the original purpose of the Rate Schedule has been frustrated. The Commission Panel notes that one circumstance that has not changed since 1987 is BC Hydro's ability to interrupt its E-Plus customers. Accordingly, the Commission Panel finds that BC Hydro has failed to meet the burden of proof in demonstrating that the E-Plus Rate Schedules are no longer just and reasonable.

BC Hydro's application to amend Rate Schedules 1105, 1205, 1206 and 1207 is denied with the exception of BC Hydro's application to amend Rate Schedules 1105, 1205, 1206 and 1207 to restrict transfer of service, which the Commission Panel finds is in the public interest and is approved.

The Commission Panel directs BC Hydro to include the interruptible service to its E-Plus customers as a separate class in its future FACOS with its next rate design application or rate design filing, and to calculate the costs of providing service as though it had the ability to interrupt the class for the four winter months, and to propose rates that move whatever R/C ratio results from this exercise to 1.0. For greater certainty, a customer receiving E-Plus service is also a member of the Residential customer class with the new "E-Plus Class" representing only the service received on the customer's E-Plus meter.

Finally, the Commission Panel directs BC Hydro to pay more attention to the exercise of its rights under the Rate Schedules and to invest the necessary time and resources to ensure that its E-Plus customers comply with the Special Conditions of the Rate Schedules, and to work with E-Plus customers who may wish to move back to the firm rate to ensure that information on Power Smart programs are made available to them.

4.3 General Service <35 kW (“Small General Service”) Rates

4.3.1 Rate Schedules

BC Hydro presently provides service to its Small General Service customers in the following Zone I Rate Schedules:

Table 4-8

Rate Schedules	
1220	Under 35 kW - Rate Zone I
1222	Converted House - Without Electric Water Heating (Closed) - All Rate Zones
1223	Converted House - With Electric Water Heating (Closed) - All Rate Zones
1205	General Dual Fuel Interruptible Service - Small Commercial Applications (Closed)

(Derived from Exhibit B-1, p. 34, Appendix D)

The Rate Schedules are applicable where a demand meter is not installed because the Customer’s demand as estimated by BC Hydro is less than 35 kW (Exhibit B-1, Appendix D, p. 10). Rate Schedule 1205 is considered in Section 4.2.

4.3.2 Rate History

BC Hydro states that Rate Schedule 1220 is presently a flat rate with only one block of energy but had been a declining block structure until 1992 when BC Hydro applied to replace the declining block structure with a flat rate in order to provide a more appropriate price signals to its small general service customers. The Commission agreed with that request and directed that BC Hydro achieve flat rates over a three year period ending April 1, 1996 (Exhibit B-3, BCUC 1.44.3).

Presently BC Hydro’s Rate Schedule 1220 rate for a period of two months is a Basic Charge of $8.83 per two month period; a charge for all energy consumed of 6.91 cents per kW.h and a minimum bill of $13.02 per two month period.

The rate class comprises approximately 170,000 customers who consume some 4,000 GW.h per year.

4.3.3 Proposed Changes to Small General Service Rate Schedules

4.3.3.1 Converted House Rates

BC Hydro states that its Converted House Rates (RS 1222 and RS 1223) were designed for single family dwellings that were converted to boarding or rooming houses or into residential suites and that the first energy block is priced at the residential rate while the second energy block is priced at the general service rate. These rates were closed in 1992, at which time there were 3,600 accounts, since which time attrition has reduced the number of accounts to approximately 1,300. BC Hydro proposes to eliminate the Converted House Rates and to transfer customers to the applicable Residential or General Service rate. BC Hydro states that if all Converted House customers were transferred to the Small General Service rate on April 1, 2008, they would experience an average net bill decrease of 0.9 percent (Exhibit B-1, p. 34).

No Intervenor challenges or comments on BC Hydro's proposal.

Commission Determination

The Commission Panel approves BC Hydro's proposal to eliminate Rate Schedules 1222 and 1223.

4.3.3.2 Basic Charge and Minimum Charge

BC Hydro states that it currently charges its Small General Service customers a Basic Charge of $8.83 per two month billing period and is not proposing any structural changes to the Small General Service rate, it proposes that other than to be consistent with how the Basic Charge is calculated in the billing system, the Basic Charge to be expressed on a per day basis at 13.77 cents per day.

BC Hydro states that its current tariff, the minimum charge on the Small General Service rate is approximately $2.10 per month higher than the Basic Charge and that to simplify the rate, it is proposing that the minimum charge on the Small General Service rate be set equal to the Basic Charge. This proposed change in the minimum charge is not expected to have a material impact on the total revenue received from this rate class (Exhibit B-1, p. 34).

No Intervenor challenges or comments on BC Hydro's proposal.

Commission Determination

The Commission Panel approves BC Hydro's proposed changes in respect of the Basic Charge and the minimum charge on the Small General Service rate.

4.3.4 Proposed Restructuring of Small General Service Rates

BC Hydro states that since the Small General Service rate class is the only rate class with a R/C ratio greater than 1.1 is (Exhibit B-1, p.24), it is proposing to use the increased revenue resulting from the proposed increases to the Irrigation rate class; the proposed changes to its Standard Charges; and the proposed increase to Residential rates to enable a reduction in the R/C ratio for the Small General Service class to under 1.1. BC Hydro is applying for an energy charge of 6.55 cents per kW.h effective April 1, 2008, resulting in a rate reduction for the Small General Service class of 5.2 percent (Exhibit B-1, Tab D, p. 10 and Tab C, p. 15).

The CEC introduces Exhibit C12-8, which contains remarks made by Messrs. Bell and Elton as executives of BC Hydro in 2003 before the Select Standing Committee on Crown Corporations of the Legislative Assembly. In that document Mr. Elton stated that "… our commercial customers are subsidizing our residential customers and our large industrial customers. This is a fairly common picture across North America. It's something that the BCUC again will deal with through a rate design hearing" (Exhibit C12-8, p. 4).

The CEC submits that the Small General Service class is particularly "unduly discriminated against" in that it will, after BC Hydro's proposed rebalancing pay 8 percent more than the cost of its service and will contribute $21.4 million annually to subsidize the Residential class of customers. The CEC submits that "there is no justification for this continued cross subsidy and it should not be perpetuated by the Commission through approval of the BC Hydro application as filed" (CEC Argument, pp. 4-5).

No other Intervenor challenges or comments on BC Hydro's proposal.

Commission Determination

BC Hydro's proposed decrease of 5.2 percent to its Small General Service Rate Schedules is denied. As noted in Section 3 of this Decision, BC Hydro's proposed range of reasonableness of 90 percent to 110 percent is denied. BC Hydro is directed to file Rate Schedules for its Small General Service class to be effective April 1, 2008, which will reflect the first phase of a three-year equal percentage phase-in to achieve the R/C ratios of 1.0 based on the revised FACOS.

BC Hydro is directed to file the revised documents referred to above with the Commission within 60 days of the date of Order No. G-111-07.

4.4 General Service > 35 kW ("Large General Service") Rates

4.4.1 Rate Schedules

BC Hydro provides service to its Large General Service customers under the following Zone I Rate Schedules:

Table 4-9

Rate Schedule	Description
1200	All Purpose - 35 kW and over - Secondary Metered, Hydro Transformers - Rate Zone I
1201	All Purpose - 35 kW and over - Primary Metered, Hydro Transformers - Rate Zone I
1206	General Dual Fuel Interruptible Service- Large Commercial Applications (Closed)
1207	General Dual Fuel Interruptible Service- Industrial Applications (Closed)
1210	All Purpose - 35 kW and over - Secondary Metered, Customer Transformers - Rate Zone I
1211	All Purpose - 35 kW and over - Primary Metered, Customer Transformers - Rate Zone I
1253	Station Service for Maintenance and Black-Starts for Independent Power Producers
1268	Distribution Transportation Access Rate for Independent Power Producers
1277	Industrial Service - (Closed) -150 kVa Demand or more- Lower Mainland and Vancouver Island South
1278	Power Service (Closed) - 2000 kVa Demand or more - Lower Mainland

(Derived from Exhibit B-1, Appendix D)

Rate Schedules 1206 and 1207 are discussed in Section 4.2 of this Decision.

BC Hydro states that the small and large general service classes are differentiated by the customer's peak demand. This rate class distinction is driven principally by metering practice (Small General Service customers do not have demand meters), although smaller general service customers typically have single phase service and larger general service customers typically have three phase service.

4.4.2 Rate History

In its 1992 Rate Design Decision (Order No. G-36-92, at Section 3.7.2), the Commission determined that the declining rate block structure used by BC Hydro for general service customers was inappropriate and should be replaced by a flat rate structure. Subsequently, in its 1993 and 1994

Revenue Requirement and Rate Design Decisions (Orders No.G-116-93, at Section 8.3.1 and No. G-89-94, at Section 7.2.2), the Commission directed BC Hydro to achieve flat rates for general service customers. BC Hydro did revise the rates to move towards this goal.

However, as noted in Section 2.2.3, BC Hydro at that time indicated that it was not possible to comply with the Commission's Order to achieve flat rates for RS 1200 (Large General Service), maintain appropriate articulation with RS 1220 (Small General Service), and collect the appropriate share of revenue requirement from each class of general service customers.

The current rate structure has been in place since April 1, 1996, with a demand/energy split rate as follows:

Table 4-10

Basic Charge	$4.42 per month
Demand Charge	
First 35 kW of billing demand per month	Nil
Next 115 kW of billing demand per month	$3.54 per kW
All additional kW of billing demand per month	$6.79 per kW
Energy Charge	
First 14,800 kW.h per month	6.91 cents per kW.h
All additional kW.h per month	3.32 cents per kW.h

(Derived from Exhibit B-1, Table 3, p. 37)

BC Hydro describes the current inclining demand charge in the Large General Service rate as atypical in that the first demand block (up to 35 kW) has no charge. BC Hydro states that the purpose of this structure was to mirror the structure of the Small General Service rate. Since customers on that rate do not have demand meters, mirroring the rate structure for the first 35 kW reduced the administrative costs of ensuring that customers close to the 35 kW threshold were on the most advantageous rate to them. Similarly the 6.91 cents per kW.h energy charge for the first 14,800 kW.h consumed each month mirrors the energy charge in the Small General Service rate. BC Hydro observes that most jurisdictions have a flat or declining demand charge, which reflects the fact that the average cost for the transmission and distribution of electricity decreases as greater load is supplied (Exhibit B-1, p. 35).

BC Hydro provides a distribution of the monthly maximum demand for its Large General Service customers:

Table 4-11

Demand (kW)	No of Customers	Percentage	Cumulative
0-35	4,227	19.1%	19.1%
35-100	11,688	52.8%	71.9%
100-150	2,162	9.8%	81.7%
150-200	1,095	4.9%	86.6%
200-300	1,167	5.3%	91.9%
300-500	906	4.1%	96.0%
500-1,000	561	2.5%	98.5%
1,000 plus	343	1.5%	100%
Total	**22,149**	**100%**	**100%**

(Derived from Exhibit B-3, JIESC 1.1.10)

BC Hydro also provides load factor data for this class:

Table 4-12

Load Factor (%)	Percentage of class
0-10	2
10-20	4
20-30	10
30-40	16
40-50	21
50-60	21
60-70	15
70-80	8
80-90	3
90-100	0
Total	**100**

(Derived from Exhibit B-3, JIESC 1.1.10)

BC Hydro says that, based on F2005 data, the maximum demand from a single customer was 10,939 kW; the median demand was 58 kW and the mean 136 kW. The total demand from the rate class is approximately 3,000 MW. BC Hydro states that the class consumes 14,500 GW.h per year with the range being from zero to 5,440,400 kW.h per month; the median monthly consumption was 18,330 kW.h and the monthly mean 50,779 kW.h (Exhibits B-3, JIESC 1.1.9; Exhibit B-7, BCUC 2.118.1, 2.118.2).

4.4.3 Proposed Restructuring of Large General Service Rates

4.4.3.1 Options Considered by BC Hydro

BC Hydro states that it developed various combinations of flat demand and energy charges for the Large General Service rate and also considered several alternatives provided by customers. In BC Hydro's view, the combination of a flat demand charge of $6.79 per kW and a flat energy charge of $0.0354 per kWh reduces the impact on those customers negatively affected by the restructuring of the Large General Service rate (Exhibit B-1, p. 36).

BC Hydro states that the alternatives it considered can be grouped into two categories:

- those which maintain the current rate transition between the small and large general service rates (which results in a customer near the boundary between the two rates paying the same bill on either rate); and
- those which do not maintain the current rate transition.

Option 1 – Maintain Rate Transition

Under this alternative, the current rate transition would be maintained by flattening the demand charges and raising the trailing energy rate. The advantages of this approach are:

- with a two-year phase in, annual bill impacts are limited to less than 10 percent per year; and
- it maintains rate transition.

The disadvantages are:

- it cannot flatten energy charge while maintaining rate transition; and
- the demand charge may still not be cost reflective.

Option 1 (which BC Hydro did not adopt) was to establish a flat demand charge of $5.30 per kW and maintain the initial demand block of 14,800 kW.h per month at $ 0.065 per kW.h with all energy thereafter at a charge of $0.0354 per kW.h.

Option 2 – Do Not Maintain Rate Transition

Under this option (which BC Hydro adopted), the current rate transition would not be maintained, allowing a full flattening of the demand and energy charges. The advantage of this approach is that it provides a demand charge that is more cost reflective, while the disadvantages are:

- the energy charge is still below the marginal cost of energy;
- the rate transition is eliminated; and
- six percent of accounts would experience bill increases of over 10 percent.

(Exhibit B-3, BCUC 1.37.1)

BC Hydro states that the following variations on Option 2 were suggested by participants at workshops it held to discuss the draft application:

1. Increase the demand charge to $7.65/kW and maintain the trailing energy charge at 3.32 cents/kW.h; and
2. Create a separate rate class for accounts with demands >2,500 kW.

BC Hydro states that under both of these variations, the total bill impact (at the end of the phase-in period) on large, high-load factor customers is reduced from approximately 5 percent to approximately zero. However, under the first variation, there number of accounts with bill increases greater than 25 percent rose from 157 to 952; and under the second variation, the number of accounts with bill increases between 5 and 10 percent rose from 470 to 4,936. BC Hydro states that it does not have the load profile data necessary to assess whether there is any cost of service basis to justify splitting the rate class between customers above and below 2,500 kW and that it is unclear whether the costs that would be allocated to either subgroup would be higher or lower than under the status quo (Exhibit B-3, BCUC 1.37.1).

4.4.3.2 Proposed Changes to the Rates and Tariff

Minimum Charge

BC Hydro states that the current minimum charge provision in the General Service >35 kW rate is the greater of $13.02 per month or 50 percent of the highest maximum demand charge billed in any month wholly within an on-peak period during the immediately preceding eleven months with the on peak period commencing on 1 November in any year and terminating on 31 March of the following year. To simplify the rate, BC Hydro proposes to remove the $13.02 component of the minimum charge, so that the minimum would be based only on the demand ratchet described above and states that this proposed change in the minimum charge is not expected to have a material impact on the revenue collected from the rate class (Exhibit B-1, p. 40).

Rate Restructuring

As part of its rate restructuring BC Hydro proposes to change its Large General Service rate, and states that in order to provide simplicity and price signals that are not contrary to the promotion of energy efficiency and conservation, it proposes to flatten the demand and energy charges for the Large General Service rate. BC Hydro states that it is not possible to flatten the demand and energy charges on the Large General Service rate while continuing to mirror the Small General Service rate since the current first block energy charge of $0.0691 per kWh is greater than the total costs allocated to the rate class of $0.0503 per kWh which means that the flat energy charge on the Large General Service rate must be less than the energy charge on the Small General Service rate.

Since its FACOS indicates that the demand-related cost of service for the Large General Service class is approximately $9.31 per kW, which is approximately 37 percent higher than the current trailing demand block on the Large General Service rate of $6.79 per kW, BC Hydro does not consider that it would be appropriate to reduce the level of the trailing demand block on the Large General Service rate and, therefore proposes to flatten the demand charge at its present level of $6.79 per kW and to flatten the declining energy charge at a level that achieves the same overall revenue from the class, which results in an increase to the flat energy charge from $0.0332 to $0.0354 per kWh (Exhibit B-1, p. 36).

In order to mitigate the impact of the proposed restructuring of the Large General Service rate on customers and to provide reasonable notice to those customers who will be negatively affected, BC Hydro proposes a three-stage approach to flattening the demand and energy charges of the Large General Service rate as follows:

- for the first and second stages on April 1, 2008 and April 1, 2009 respectively, to increase the charge for the initial demand blocks and to lower the charge for the initial energy block; and
- for the third stage on April 1, 2010, to complete the flattening of the demand and energy charges.

BC Hydro also proposes to mitigate the impact by offering customers adversely impacted by the restructuring of the Large General Service rate the opportunity to participate in Power Smart programs to increase their energy efficiency and thereby reduce the impact of the restructuring of the rate (Exhibit B-1, pp. 36, 40).

BC Hydro states that while it doubts that further structural changes to the Large General Service rate will be able to take place until after phase-in of the flat demand and energy charges is complete, it considers that the proposed three year phase-in strikes an appropriate balance between providing more efficient price signals and mitigating the impact on adversely affected customers (Exhibit B-3, BCUC 1.5.5.2).

4.4.3.3 Impact on customers

BC Hydro states that the impact on monthly customer bills of its proposal would be as follows:

Table 4-13

(Reduction) / Increase	Number of customers
($3,000 +)	247
($1,500-$3,000)	6,052
($0-$1,500)	7,509
$0-$1,500	3,574
$1,500-$3,000	2,079
$3,000 - $15,000	2,496
$15,000+	236
Total	22,193

(Derived from Exhibit B-3, JIESC 1.1.2)

BC Hydro sets out the percentage increase or (decrease) that its customers will experience after the three stages as follows:

Table 4-14

Cumulative Monthly Bill Impact, Proposed Rates:

	Difference - $ Load Factor			Difference - % Load Factor		
kW	25%	50%	75%	25%	50%	75%
35	22	-193	-251	5.0%	-21.7%	-21.5%
50	-21	-205	-185	-3.1%	-17.1%	-12.3%
75	-93	-104	-74	-8.6%	-6.5%	-3.6%
100	-42	-3	37	-3.1%	-0.1%	1.4%
150	140	200	259	7.6%	7.2%	7.1%
250	180	279	378	5.7%	6.0%	6.1%
500	279	477	675	4.4%	5.1%	5.4%
1000	477	873	1,269	3.7%	4.6%	5.1%
2000	873	1,665	2,457	3.4%	4.4%	4.9%
5000	2,061	4,041	6,021	3.2%	4.3%	4.8%

Source: Exhibit B-3, BCUC 1.37.1, p. 4

The following table compares the effect of BC Hydro's proposal on the average unit price of electricity to be paid by its customers having the following demand at 50 percent Load Factor with existing rates:

Table 4-15

kW	Monthly Usage at 50% Load Factor	Proposed Total Cost ($ / month)	Proposed Rates Average Unit Price (cents per kW.h)	Present Total Cost $ / month	Existing Rates Average Unit Price (cents per kW.h)
35	12,775	$694	5.43	$887	6.94
50	18,250	$990	5.42	$1,195	6.55
150	54,750	$2,960	5.40	$2,761	5.04
1,000	365,000	$19,705	5.40	$18,832	5.16
5,000	1,825,000	$98,505	5.40	$94,464	5.18

(Derived from Exhibit B-1, Appendix C, Schedule 8.0, p. 12)

4.4.4 JIESC's Evidence

The JIESC presented a second witness panel comprising Mr. Guenther, whose evidence related to the proposed restructuring of the Large General Service Class of customers and the appropriate range for revenue-to-cost ratios (Exhibit C18-7), and four policy witnesses: Messers. Allan of the Council of Forest Industries ("COFI"), Jordan of Canfor, Towers of Tolko Industries and LeGrow of West Fraser Mills, to address policy and impacts (Exhibit C18-9).

The policy witnesses provided evidence as to the nature of the Large General Service rate and the impact of the options considered by BC Hydro on their affected operations. The written evidence of the panel states in part that:

> "While BC Hydro's charts make it look like there may be a small number of customers worse off, the reality is that some customers will be badly harmed if BC Hydro proceeds with its proposal."
>
> ……
>
> "What also makes these rate increases particularly objectionable, in addition to their magnitude, is that these increases are not based on a need by BC Hydro for additional revenue, as all of the revenue derived from these increases will be redistributed to others within the class. Nor are these increased costs due to an inadequate revenue to cost ratio for this class, or any customers within it. They are justified solely on the grounds of restructuring the rate to eliminate the existing declining block rates" (Exhibit C18-9, p. 4).

A JIESC policy witness testified that the major power users such as their forest company operations receive the correct price signals from the present rate, and provided details of their conservation efforts in recent years to demonstrate that the existing rate structure promotes both energy efficiency and conservation at their companies (T9:1472-73). The three major forest products companies stated that their facilities which fall into RS 1211 have all had studies completed or in progress which have been funded by BC Hydro's Power Smart Partners program. Table 4-16 summarizes the estimated potential savings from the studies:

Table 4-16

Company	# of facilities	Estimated potential savings (MW.h per year)
Canfor	7	15.6
Tolko	3	7.1
West Fraser	4	10.1

(Derived from Exhibit C18-12, BC Hydro 1.2.7)

Table 4-17 summarizes the policy witnesses filed evidence on the impact of BC Hydro's proposed changes on the affected accounts of the three major forest product companies:

Table 4-17

Company	Annual Impact ($000)
Canfor	521
West Fraser	295
Tolko	134
Total	950

(Derived from Exhibit C18-9, p. 4, citing JIESC 1.1.4-6)

The JIESC submits that the operations of these three companies are price takers, not price makers and cannot pass on any increased cost to customers. The JIESC submits that some customers would be badly harmed by BC Hydro's proposal and it would affect the profitability and possibly the viability of the companies shown in Table 4-17 (Exhibit C18-9, pp. 4-5).

Table 4-18 summarizes the further evidence filed by the JIESC on the impact of Option 1 on all the Large General Service accounts of three major forest product companies in response to an undertaking:

Table 4-18

Company	Annual Impact ($000)
Canfor	"bill neutral"
West Fraser	(125)
Tolko	(54)
Total	(179)

(Derived from Exhibit C18-24, p.2, citing BCUC 1.6.0, Attachment 1, slides 19-22)

The JIESC policy witnesses testified that limited Stakeholder Engagement has taken place between themselves and BC Hydro concerning the rate structure under Rate Schedule 1211 and alternatives to it [as summarized in Section 2.5 above] (T9:1475-76), and as further evidenced by the following exchange between Commissioner Milbourne and the JIESC policy panel:

> COMMISSIONER MILBOURNE: In terms of the operations that you do have on the stepped rates …have you seen indications that it influences the behavior at the actual operation level …?
>
> MR. JORDAN: Well, certainly, the stepped rate, you know, for those of our mills that are on 1823, is increased awareness on electricity use dramatically, because it now offers an incentive to save money by reducing that Tier 2 … (T9:1467)
>
> [Further in the exchange]
>
> COMMISSIONER MILBOURNE: But are you actually seeing measurable results?
>
> MR. JORDAN: Yes.
>
> MR. TOWERS. Yeah, we've also implemented a lot of opportunities at our 1823 mills as well. (T9:1467-1468)
>
> [And further in the exchange]
>
> COMMISSIONER MILBOURNE: … in terms of the solution to the same issue set that perhaps has a higher potential of influencing peoples behavior to accomplish conservation, would I be correct in assuming that the stepped rate structure would have a greater influence? Give you a greater influence to actually affect more effective use, utilization of energy?

MR. LEGROW: Yes

MR. JORDAN: Yes, I would concur with that as well.

COMMISSIONER MILBOURNE: Thank you. Those are --

MR. JORDAN: If versus the 1211proposed flat structure there was a stepped rate type of structure, similar to the 1823, that would provide a better price signal for conservation (T9:1470-1471).

4.4.5 Other Alternatives

The written evidence of Mr. Guenther states that declining block rates make fewer rate schedules possible by recovering the fixed costs in the fixed charges and the initial rate steps but that more rate schedules are needed to reflect the differences in load characteristics and cost of service when moving away from a declining block rate structure. It further states that BC Hydro has not developed new rate schedules that take into account differences such as load factor and consumption or the alternative of maintaining two-part rates for the large commercial and industrial customers within the Large General Service rate class and does not appear to recognize any need to do so (Exhibit C18-7, p. 4).

The written evidence also states that “There is no simple elegant solution that will work with a single rate” and proposes a number of potential solutions to the problems it perceives are caused by BC Hydro’s proposal to restructure the Large General Service rate. The JIESC’s first recommendation is to “review customers in the GS>35 kW rate class to ensure that they qualify for the rate. This step would remove some customers with low consumption who would receive large percentage rate decreases from the class. If revenue neutrality within the rate class is required, a decrease for one customer requires an increase for another customer”. The JIESC’s second recommendation is to “set up a rate within the distribution class based on RS1823 with a rate rider for distribution service (similar to the application of a bypass rider), bill or revenue neutrality for all GS>35 kW customers with a demand in excess of 3,000 kW or even 1,000 kW. This will isolate those customers with large dollar bill impacts and provide the price signal of the stepped rate” (Exhibit C18-7, pp. 6-7).

The JIESC states that if its second recommendation is not implemented, then the following options should be considered for large customers:

- separate GS rates for customers with demands in excess of 1,000 or 3,000 kW as appropriate; or
- maintaining the stepped rates for customers with demands in excess of 1,000 or 3,000 kW.

For customers under the GS rate schedule with demands less than 1,000 or 3,000 kW the JIESC recommends that BC Hydro design GS rates that minimize the bill impact, considering both percentage and dollar impacts, such as:

- a change in the 35 kW demand break point for GS rates to “something higher”; and
- more than two GS rates for customers with a demand less than 1,000 or 3,000 kW as appropriate.

  (Exhibit C18-7, p. 7)

In Argument BC Hydro submits that it responded to a number of IRs from the JIESC to examine options for various potential subgroups of the Large General Service class including:

- subdividing the rate class into primary and secondary service (addressed in Section 4.4.5.1);
- subdividing the rate class at 200 kW and at either 1,000 kW or 3,000 kW (addressed in Section 4.4.5.2); and
- subdividing the rate class at either 200 kW or 300 kW and at 3,000 kW, with a rate for either the > 1,000 kW or the > 3,000 class based on Rate 1823 plus a “distribution rider” (addressed in Section 4.4.5.3).

  (BC Hydro Argument, pp. 46-47)

4.4.5.1 Primary and Secondary Service

BC Hydro states that the only difference between primary and secondary service is whether the customer or BC Hydro owns the transformer and considers that it is more appropriate to maintain a single rate class and provide primary service customers with a credit for transformer ownership, rather than subdividing the rate class (Exhibit B-7, BCUC 2.68.2). BC Hydro estimates that the difference in the R/C ratios between primary service and secondary service is only approximately four percent, which in BC Hydro's view is not sufficient to warrant a separate rate class with higher rates for primary service customers (Exhibit B-50). The JIESC agrees with BC Hydro that the internal COS estimates should not be utilized but relies upon different reasons. The JIESC is particularly concerned the supporting details for these studies were not presented, it appears they are directional estimates only, and, most importantly, they have not been subject to the same detailed scrutiny that the filed FACOS studies based on rate classes have (JIESC Argument, p. 18).

4.4.5.2 Subdividing the Rate Class at 200 kW and at either 1,000 kW or 3,000 kW

The JIESC requested that BC Hydro provide the rates and bill impacts assuming three separate General Service rate sub-groups, and revenue neutrality for the new rate classes with A) separate rate classes for customers with demands i) up to 200kW; ii) between 200 kW and 1,000 kW and iii) above 1,000 kW; and B) separate rate classes for customers with demands i) up to 200kW; ii) between 200 kW and 3,000 kW and iii) above 3,000 kW. In response, BC Hydro developed the following rates:

Table 4-19

	Rate for < 200 kW	**Rate for all demand > 200 kW**
Demand	6.79	6.79
Energy	.0393	.0332

(Derived from Exhibit B-7, JIESC 2.13.4.1)

The Commission Panel has assessed the impact on monthly customer bills as follows:

Table 4-20
Scenarios A and B

(Reduction) / Increase	Number of customers < 200 kW	Number of customers > 200 kW	TOTAL
($3,000 +)	15	0	15
($0-$3,000)	10,750	24	10,774
$0-$3,000	6,444	2,956	9,400
$3,000 - $6,000	1,557	-	1,557
$6,000+	447	-	447
Total	**19,213**	**2,980***	**22,193**

(Derived from Exhibit B-7, JIESC 2.13.4.1
* Assuming for convenience that no account had a bill impact greater than $3,000.)

To give further perspective, BC Hydro states that compared to its proposed restructuring of the Large General Service rate, applying the separate rates for the three sub-groups would result in a 36 percent increase in the number of accounts with annual bill increases (11,404 compared to 8,385), including a 15 percent increase in the number of accounts with annual bill increases greater than 10 percent (673 versus 585) (Exhibit B-7, JIESC 2.13.4.1).

Table 4-21

Bill Impacts from Restructuring of
General Service > 35 kW Rate into 3 Rate Classes

Increase/(Reduction)	Number of Customers
(10%) -(20%)	168
(5%)-(10%)	1,970
(5%)-0%	8,651
0%-5%	10,069
5%-10%	662
10% +	673
Total	**22,193**

(Derived from Exhibit B-7, JIESC 2.13.4.1 by summarizing the information for the first and last category.)

4.4.5.3 Rate Schedule 1823 Based Distribution Rider Proposal

The concept of subdividing the rate class at either 200 kW or 300 kW and at 3,000 kW, with a rate for either the “> 1,000 kW” or the “> 3,000 class based on Rate 1823 plus a “distribution rider”, was also analyzed in the IR process. BC Hydro’s responses to JIESC IR 2.13.5.1 and 2 regarding these alternatives suggest the following rates:

Table 4-22

	Both <200 and <300kW	**Both 200-3000kW and 300-3000 kW**	**Both >1000 and >3000kW with rider**
$ per month per kW	6.79	6.79	5.99
Cents per kW.h	3.93	3.32	3.51

(Derived from Exhibit B-7, JIESC 2.13.5.1, 2.13.5.2)

BC Hydro states that the impact would be similar to the impacts in its subdividing the rate class at 200 kW and at either 1,000 kW or 3,000 kW (Exhibit B-7, JIESC 2.13.5.1-2).

4.4.6 BC Hydro and Intervenor Arguments

BC Hydro submits that further restructuring of the rate class cannot take place if there is no final resolution in this proceeding of what the structure should be for at least the next few years and notes that the JIESC have only proposed high-level alternatives to BC Hydro’s proposal, which require further study by BC Hydro, and are not rate structures that could be imposed by April 1, 2008. BC Hydro submits that:

> “It follows that rejection of BC Hydro’s proposal in favour of the JIESC’s can at best delay the proposed restructuring of the GS > 35 kW rate class, and at worst cause any further and more meaningful restructuring to be postponed past the point in time where it can assist BC Hydro in meeting the 2020 conservation goal set by the 2007 Energy Plan. Any such delay will compromise the message of conservation that all BC Hydro customers will be hearing about from BC Hydro” (BC Hydro Argument, p. 13).

BC Hydro addresses the JIESC's proposal that the "> 1,000 kW" or "> 3,000 kW" subgroups be kept whole as compared to current rates, and submits that there is no cost justification for shielding these subgroups from the impact of the proposed restructuring of the GS > 35 kW rate class. Furthermore, as indicated in the responses to the JIESC IRs 2.13.4.1 and 2.13.5.1, keeping these subgroups "whole" as proposed by the JIESC would result in a significant increase in the number of accounts that would experience bill increases, and a significant increase in the number of accounts that would experience bill increases greater than 10 percent. Finally, BC Hydro notes that "there is no logical end-point to an exercise of creating subclasses for the purpose of mitigating bill impacts arising from restructuring. Each adversely affected member of a subclass would have the same basis for a further division of the subclass, ultimately leading to a rate class for every customer" (BC Hydro Argument, pp. 47-8).

BC Hydro addresses the alternative of creating a rate for the "> 1,000 kW" or "> 3,000 kW" subgroups based on Rate 1823 plus a distribution rider, and submits that its experience with the stepped transmission rate is that it is complex and expensive to administer, and that its RS 1823 customers are still learning how to adjust to the rate, and "are not keen to see it changed, despite its four-year development history" (BC Hydro Argument, p. 48).

BC Hydro goes on to submit that it would be wrong to assume that the stepped rate model that was selected for industrial class customers would be appropriate for any subdivision of the GS > 35 kW class and that Intervenors who specifically represent customers other than forestry product companies could have had no reasonable way of knowing from anything BC Hydro has proposed that such a rate structure might be an outcome of this proceeding. BC Hydro notes that GS > 35 kW customers have the option of applying to the BCUC for approval of a bypass rate which would, if approved, result in the application of the stepped transmission rate to those customers. For all of the above reasons, BC Hydro submits that JIESC's proposal to subdivide the GS > 35 kW class cannot be justified on a cost causation basis and should be rejected, and that it would be premature to extend the stepped transmission rate structure to smaller customers on the GS > 35 kW rate at this time (BC Hydro Argument, p. 49).

The JIESC submits that it has proposed practical alternatives for restructuring the GS>35 kW rate class and that two plausible solutions that would not have the adverse impacts of the BC Hydro proposal are:

1. Creating a separate class for the larger customers in the GS > 35 kW rate class whereby a separate class be created with a break point somewhere between 1000 kW and 3000 kW and that doing so would result in rates that are close to revenue neutral for these customers and achieve the rate levelization targets of BC Hydro.

2. Creating an optional 1823-like rate (the JIESC's preferred option) whereby BC Hydro would charge rate schedule 1823 rates with an individually calculated rider to ensure that the customer is revenue neutral at current consumption levels to GS > 35 kW rates. The JIESC submits that this option has several advantages:

   - it would be revenue neutral for all customers at current consumption;

   - in line with the Energy Plan, it moves the next group of large customers, after Rate Schedule 1823, to stepped rates where they will receive what are generally considered appropriate long term price signals. In the absence of taking a step like this, it is unlikely that these customers will receive these price signals for another 2 to 4 years based on BC Hydro's schedule of rate regulatory proceedings; and

   - it is practical and can be done quickly and easily.

(JIESC Argument, pp. 21-22)

The JIESC considered BC Hydro's argument that the Large General Service customers already have a virtual bypass option and observed that this option is not the same as what is being presented by the JIESC in that the rider in the RS 1823 virtual bypass option that is currently available to RS 1211 customers is based on the cost of facilities to connect to the transmission network, (which cost is highly dependent on the location of the customer's facilities) and the rider proposed by the JIESC is based on Rate Schedule 1211 neutrality, while keeping BC Hydro whole at distribution rates and increasing the number of customers on stepped rates (JIESC Argument, p. 23).

BCOAPO submits that it does not support the JIESC's contention that it is unfair to increase a customer's bill in an effort to promote a more efficient rate structure when no overall revenue requirement is being requested and the class revenue-to-cost ratio is acceptable. BCOAPO suggests that if the Commission embraces FACOS and finds that any class with an R/C between 90 and 110 percent is paying its full cost of service, then the JIESC position would mean that the starting point for any rate restructuring options has to be zero customer bill impact. This approach will completely hamstring any move to more efficient rate structures (BCOAPO Argument, p. 24).

BCOAPO further submits that although it recognizes that the JIESC rate proposal for General Service class customers with demands greater than 1 or 3 MW would provide a marginal price signal, the JIESC proposal should be rejected on the grounds that these customers already have a Bypass Rate option if they want access to Rate Schedule 1823. The JIESC proposal simply results in a cheaper Bypass option at the expense of other customers and provides these Large General Service customers with access to BC Hydro's least expensive major rate schedule, Schedule 1823, for any plant expansion (BCOAPO Argument, pp. 24-25).

The CEC submits that bill neutrality should not be a goal in restructuring rates but that transition time is important to mitigate the impact of significant rate increases on customers and that there is not enough evidence at this time to assess the creation of a cost-based sub-group in the Large General Service class (CEC Argument, pp. 73-74).

In Reply, BC Hydro submits that it remains of the view that the JIESC's proposal to subdivide the Large General Service class cannot be justified on a cost causation basis and that the stepped transmission rate structure should not be extended to smaller customers on the Large General Service rate at this time (BC Hydro Reply, p. 25).

4.4.7 Ineligible Customers

The JIESC states that 4,227 customers do not appear to meet the requirements of the rate class (Exhibit C18-7, p. 5).

BC Hydro states that, based on F2005 data, the accounts on the Large General Service rate with an average monthly maximum demand of less than 35 kW have an average annual energy consumption of 87,000 kWh; an average annual bill of $5,800, and an average annual maximum demand of 36 kW (Exhibit B-3, BCUC 1.35.2). BC Hydro estimates that 1,321 accounts on the Large General

Service rate registered demand of less than 35 kW in each billing period during the 12 month period ending March 2005 (F2005). Further, 224 accounts registered zero demand for the F2005 year.

The JIESC advocates that BC Hydro clean up the class and remove those who do not belong. The JIESC submits that 4,000 customers appear not to qualify as they are shown as having demands less than 35 kW. BC Hydro provided some clarity in Exhibit B-29 on why there were 4,000 customers shown as having demands of less than 35 kW, indicating that while the average demand some of those customers was under 35 kW *"there could be months in the year where the accounts did have over 35 kW demand" (emphasis added).* In the JIESC's submission, the possibility there could be months in a year where customers would have a demand over 35 kW is not enough to justify membership in the class. The JIESC argues that BC Hydro acknowledges 1,321 accounts that do not belong in the class, but apparently excuses them on the ground that they will be replaced by a similar number that do not belong there (JIESC Argument, p. 21).

In Reply BC Hydro notes from Exhibit B-29 that the total decrease in revenue from the accounts that in March 2005 no longer qualified for the Large General Service rate would be only $1.2 million, less than 0.2 percent of the total revenue for the Large General Service rate class. BC Hydro therefore submits that any impact of rate switching for customers near the border between the two General Service rates would not have a material impact on other Large General Service customers (BC Hydro Reply, p. 24).

Commission Determination

The Commission Panel is of the opinion that while BC Hydro's statement that the declining block rate structure sends customers the wrong signal and fails to encourage conservation may be applicable for the majority of the Large General Service class, it is not necessarily true for all members of the Large General Service class. As can be seen from the calculations in Table 4-15, under the existing Rate Schedule the average unit cost of electricity declines with increased consumption for customers having a demand of less than 150 kW, who represent 81.7 percent of the class, but for customers with a demand greater than 150 kW, who represent 18.3 percent of the class, the average unit cost stays relatively constant. Further, the evidence before the Commission Panel is that the Rate has not discouraged three of the largest customers in the class from participating in conservation initiatives.

The evidence before the Commission Panel is that BC Hydro's proposal results in reducing the average unit cost of electricity for those members of the class whose demand is less than 150 kW and in increasing the average unit cost of electricity to those members of the class whose demand is greater than 150 kW. The Commission Panel notes that BC Hydro's proposal results in monthly bill reductions to 13,808 customers in the class and increases to 8,385, but that the increases are large in dollar terms to the high demand, high load factor customers.

The evidence before the Commission Panel is that BC Hydro's stakeholder engagement process consisted of two workshop meetings at which only two options (one of which retained a declining block structure) were presented to customers, and that part of BC Hydro's proposed mitigation was an offer of participation in its Power Smart programs, which were programs already in existence.

The Commission Panel finds that BC Hydro's proposed restructuring of its Large General Service class was ill-conceived and poorly executed. The proposal is denied.

The Commission Panel does not accept the JIESC's proposal that the class be split at 1,000 kW demand or higher on the grounds that this will leave customers with a demand of 150 kW or greater shouldering the entire transfer that BC Hydro's proposal entails. The Commission Panel also rejects the JIESC's proposal of an 1823-like rate for the major users with a distribution rider to keep them revenue neutral for the same reason. Notwithstanding these findings based on the evidence in this proceeding, these concepts may well have merit in future proposals for this rate class.

The Commission Panel is also concerned that while it heard statements from BC Hydro that further structural changes to the Large General Service cannot be undertaken until after its proposed phase-in period, it did not receive any indication of what those changes may look like, and as a result the Commission Panel cannot be sure that where BC Hydro's proposal takes the class would be a logical place to start further structural changes. In the Commission Panel's view the stakeholder engagement should start with the long view rather than vice versa.

The Commission Panel agrees with the JIESC that there is no elegant solution and that on the basis of the evidence before it, there is no option it can direct BC Hydro to pursue. **Accordingly, BC Hydro is directed to commence meaningful stakeholder engagement with its Large General Service customers to develop, and file with the Commission an application for a rate structure or structures that encourage conservation without unduly benefiting or harming any of its customers in that class. Such a rate structure or structures should be in place by April 1, 2009 with a two-year phase-in if necessary.**

As noted in Section 3 of this Decision, BC Hydro's proposed range of reasonableness of 90 percent to 110 percent is denied. BC Hydro is directed to file Rate Schedules for its Large General Service class to be effective April 1, 2008, which will reflect the first phase of a three-year equal percentage phase-in to achieve the R/C ratios of 1.0 based on the revised FACOS.

BC Hydro is directed to file the revised documents referred to above with the Commission within 60 days of the date of Order No. G-111-07.

4.5 Irrigation Rates

4.5.1 Irrigation Rate Schedule

Irrigation service is provided to customers under Rate Schedule 1401. BC Hydro currently charges 3.32 cents per kW.h (the base rate) in the irrigation season and during the non-irrigation season BC Hydro charges its irrigation customers the base rate per kW.h for the first 150 kW.h and a penalty rate of 26.38 cents per kW.h for all additional consumption. BC Hydro proposes no change to the penalty rate.

4.5.2 Rate History

There is no evidence as to the history of Rate 1401. BC Hydro testified that the rate has changed from a farm rate to a pumping rate over the years:

> THE CHAIRPERSON: And I guess this may have started off life as a farmed (sic) rate taking power in the irrigation season during the freshet when there's lots of energy around. But then it sort of morphed into a pumping rate. Anyone who has a pump of over 730 kilowatts, or 1 horsepower, I guess, gets this rate.
>
> MS. ZACHARIAS: A: That's right. (T8:1268)

4.5.3 Customer Data

BC Hydro states that it has approximately 3,370 customers on RS 1401 consuming 96 GW.h per year with an estimated maximum demand of 46 MW (BCUC 1.51.1) It estimates that 89 percent of its irrigation customers are farms or ranches (3,000), 2 percent are municipalities (70) and 9 percent are golf courses hotels and resorts (300) (BCUC 2.103.1), and testified that the municipalities and hotels/golf courses are the largest customers in this rate class (T8:1268).

4.5.4 Proposed Changes to Irrigation Tariffs

Under BC Hydro's current tariff, irrigation customers who supply their own transformation from a primary potential to a secondary potential are not eligible for a discount and, therefore, pay the same rate as an irrigation customer with the same load but who does not supply its own transformation. Other residential and general service customers who supply their own transformation from a primary potential to a secondary potential are eligible for a discount of $0.25 per kW per month. To provide fair treatment of irrigation customers who supply their own transformation, BC Hydro is proposing to offer the same discount for ownership of transformers to irrigation customers as is currently offered to residential and general service customers. If approved, the Rate Code for irrigation customers eligible for the discount for transformer ownership would be 1402. This proposed change is not expected to have a material impact on the total revenue received from this rate class.

No Intervenor challenges or comments on BC Hydro's proposal.

Commission Determination

BC Hydro's proposal to create Rate Schedule 1402 is approved.

4.5.5 Proposed Changes to Irrigation Rate

As part of its Rate Rebalancing BC Hydro is proposing a ten percent rate increase for irrigation customers to commence on April 1, 2008 in the first year, followed by further annual increases of 7.5 percent for that class on April 1 of each of the following four years, 2009, 2010, 2011 and 2012 as follows:

Table 4-23

Currently	3.32 cents per kW.h
April 2008	3.65 cents per kW.h
April 2009	3.92 cents per kW h
April 2010	4.21 cents per kW.h
April 2011	4.53 cents per kW.h
April 2012	4.87 cents per kW.h

(Derived from Exhibit B-1, Appendices D and E)

BC Hydro states that the only rate class with a revenue-to-cost ratio less than 90 percent is the Irrigation rate class And that by April 1, 2012, the revenue-to-cost ratio for the Irrigation class would be 94.7 percent, approximately the same as the revenue-to-cost ratio for residential customers. BC Hydro testified that the revenue-to-cost ratio for the rate class in its 1991 FACOS was 133.6 percent and that the reason for the considerable reduction was that the 1991 study allocated no primary distribution costs to irrigation, while the 2007 study assumed that the bulk of the irrigation customers are served at secondary voltage levels (T8:1266). To correct Exhibit B-3, BCOAPO 1.7.3 which stated that irrigation customers are served at the primary level, BC Hydro filed Exhibit B-78, which states that they take service at the secondary level.

Commission Determination

BC Hydro's proposed increase to its Irrigation customers is denied. As noted in Section 3 of this Decision, BC Hydro's proposed range of reasonableness of 90 percent to 110 percent is denied. BC Hydro is directed to file Rate Schedules for its Irrigation class to be effective April 1, 2008, which will reflect the first phase of a three-year equal percentage phase-in to achieve the R/C ratios of 1.0 based on the revised FACOS.

BC Hydro is directed to file the revised documents referred to above with the Commission within 60 days of the date of Order No. G-111-07.

4.6 Street Lighting Rates

4.6.1 Rate Schedules

BC Hydro provides Street Lighting service under the following Rate Schedules:

Table 4-24

Rate Schedule	Description
1701	Overhead Street Lighting - All Rate Zones
1702	Ornamental Street Lighting - All Rate Zones
1703	Street Lighting Service - Restricted Areas
1704	Traffic Signals, Traffic Signs & Traffic Warning Devices -All Rate Zones
1755	Private Outdoor Lighting (Closed) - All Rate Zones
1761	Overhead Street Lighting (Closed)
1770	Street Lighting Service (Closed) - Kitimat Area

(Derived from Exhibit B-1, pp, 40-41, Appendix D)

4.6.2 Proposed Changes to Terms and Conditions

BC Hydro states that Rate Schedule 1701 is for streetlights that are installed, owned and maintained by BC Hydro on BC Hydro poles and that the only change proposed to Rate Schedule 1701 is the elimination of the charges for incandescent and fluorescent lights, since these technologies are no longer used for BC Hydro owned streetlights.

BC Hydro states that Rate Schedules 1761 and 1770 are closed rates with no customers still taking service under them and that it is therefore proposing to eliminate Rate Schedules 1761 and 1770.

Commission Determination

BC Hydro's proposal to eliminate Rate Schedules 1761 and 1770 is approved.

BC Hydro's proposed range of reasonableness of 90 percent to 110 percent is denied. BC Hydro is directed to file Rate Schedules for its street lighting class to be effective April 1, 2008, which will reflect the first phase of a three-year equal percentage phase-in to achieve the R/C ratios of 1.0 based on the revised FACOS.

BC Hydro is directed to file the revised documents referred to above with the Commission within 60 days of the date of Order No. G-111-07.

5.0 TERMS AND CONDITIONS

This Section of the Decision deals with BC Hydro's proposed changes to the Terms and Conditions of its Electric Tariff and particularly with the substantive changes BC Hydro is proposing for its Distribution Extension Policy and its Minimum Connection Charges.

5.1 Overview

BC Hydro filed its proposed Terms and Conditions as Appendix F to the Application. BC Hydro states that in order to simplify the use of the Terms and Conditions, it is proposing to re-order and group the current sections under eleven new headings.

BC Hydro states that it is proposing substantive changes to the Terms and Conditions relating to the following matters:

- Distribution Extension Policy;
- Minimum Connection Charges;
- Prepaid Metering;
- Security Deposits;
- Minimum Reconnection Charges; and
- Miscellaneous Charges.

BC Hydro further states that it is proposing a number of routine changes to its Terms and Conditions, such as the removal of obsolete language, definitions and terms and clarification of the following matters:

- a customer must provide reasonable access to BC Hydro (or its Agent);
- a customer must provide and maintain all civil work required for underground Service Connections;

- estimated bills;
- minimum charges (for) a suite in a new multi-unit residential building;
- over-billing;
- customer must advise BC Hydro in advance and receive BC Hydro's approval before increasing their electrical load to more than 80 percent of the rated capacity of the customer's main switch;
- the five-year period for the refund of Extension Fees commences when the Extension is energized;
- the option of accepting an allowance toward the Extension Fee based on BC Hydro's forecast of the number of services expected to be connected in the first five years applies to subdivisions comprised primarily, but not necessarily exclusively, of residential customers; and
- facilities provided or constructed by the Customer must meet both BC Hydro's distribution and environmental standards.

(Exhibit B-1, pp. 54-5)

With the exception of BC Hydro's proposed Distribution Extension Policy and Minimum Connection Charges, no Intervenor challenges or comments on BC Hydro's proposals.

5.2 Distribution Extension Policy

5.2.1 BC Hydro's Current SET Policy

BC Hydro states that for services that require an extension to the distribution system, customers are required to pay an extension fee equal to the estimated construction cost of the extension less the investment made by BC Hydro and that under its current tariff, the amount of its investment ("Allowance") is based on the difference between the expected incremental revenue ("Revenue Margin") and the estimated incremental costs ("Net Construction Costs") of supplying the new load.

BC Hydro's current Terms and Conditions in its Electric Tariff define the System Extension Test (SET) as "A discounted cash flow (DCF) model used by BC Hydro to evaluate the economics of an Extension and/or a Service Connection." The SET includes, without limitation, the following components:

1. Net Margin is the difference between the Revenue Margin and Net Construction Cost.

   The Net Margin is positive when the Revenue Margin is equal to or exceeds Net Construction Cost; the Net Margin is negative when the Net Construction Cost exceeds the Revenue Margin.

   Revenue Margin, made up of: Electricity revenues, less:

   - Cost of Electricity,
   - Upstream Cost of Transmission,
   - Net operating & maintenance costs,
   - School taxes,
   - Grants in lieu of taxes,
   - Capital taxes, and
   - Retail Costs.

Net Construction Cost, made up of:

- Estimated Construction Cost of the Extension and/or
- Service Connection, Refund Processing Cost and
- System Improvement Costs, less:
  - Connection Charges,
  - Maximum Terminal Value, and
  - Third party contributions (capital).

2. Revenue Projections

Electricity revenue projections used in the SET are based on current approved rates for electric service. If the SET is done for an Extension, then the SET will consider the revenue based on the connected load of those applicants that are connecting to the Extension. If the SET is done for a Service Connection, then the SET will consider the revenue based on the connected load of the applicant. Electricity revenue does not include any taxes (except those defined in Revenue Margin), interest charges, late payment charges, power factor surcharges or other miscellaneous charges.

Where there is reasonable certainty of future Customer additions, BC Hydro may include the projected electricity revenues and costs of such Customers in the SET.

3. Evaluation Period

The evaluation period for the SET will be 10 years.

4. Impermanence of Load

Where BC Hydro has determined that an applicant's load and the extension required to serve it will occur for a period of less than 10 years and there is no likelihood of additional future Customers, B.C. Hydro may adjust the Evaluation Period to reflect the estimated years of use.

5. Discount Rate

The discount rate for the SET will be BC Hydro's weighted average cost of capital.

Additional definitions for the SET also include, without limitation, the following:
Connection Charges are the sum of:

(a) the charge for a Service Connection as set out under "Service Connection Charges"; and

(b) the Estimated Construction Cost of any Dedicated Facilities.

Cost of Electricity is the future incremental cost of generation and 500 kV (bulk) transmission as estimated by BC Hydro to serve a Customer's new load.

Maximum Terminal Value is the present value of the lesser of:

(a) the depreciated value of facilities at the end of year 10; or

(b) the Revenue Margin from years 11 to 40.

The Maximum Terminal Value will not be less than zero.

> Retail Costs are those incremental costs that BC Hydro estimates for the meter reading, billing, account inquiry functions, and other administrative costs required to serve a new Customer.
>
> Refund Processing Cost is the annual administrative cost that BC Hydro estimates to process the first refund requests, divided by the annual number of Extensions that BC Hydro estimates will be constructed.
>
> System Improvement ("SI") costs are the future incremental costs that BC Hydro estimates will be incurred on the distribution system, including distribution substations, as a result of a Customer's new load.
>
> Upstream Cost of Transmission is the future incremental cost that BC Hydro estimates will be incurred on its transmission facilities up to the 360 kV level as a result of a Customer's new load (Exhibit B-1, Appendix G, pp 12-14).

BC Hydro provided some amplification of its current calculation methodology, stating that the actual cost of electricity used for a specific SET calculation will vary by its service region, type of account (residential or commercial), type of dwelling (e.g. single family, apartment), heating source, with the result that each SET calculation will result in a specific cost of electricity for the account due to that account's characteristics (Exhibit B-7, Terasen 2.6.4), and that upstream cost of transmission is the customer's peak kW load multiplied by the feeder coincident load factor multiplied by the substation coincident load factor multiplied by the area transmission cost per kW divided by the customer's power factor. BC Hydro also states that the area transmission cost per kW varies by region**,** and that net operating & maintenance ("O&M") cost is based on the length of the extension multiplied by the applicable O&M costs which vary by region, plus a maintenance cost for each electric meter installed, less a credit from Telus for any joint use poles (Exhibit B-7, BCOAPO 2.26.2).

5.2.2 Regulatory Background

By Order No. G-80-96 the Commission issued its Decision concerning a generic hearing into utility system expansions and published its System Extension Test Guidelines ("SET Guidelines"), where it stated at page 31:

> "In order to facilitate a degree of consistency and to assist Utilities with regard to approaches the Commission anticipates using in its reviews of system extensions or extension tests, the Commission has provided the following guidelines in order to indicate the type and format of the information which it may require in its reviews."

In January 1997 BC Hydro filed its Policy for System Extension Tests, which was approved by the Commission by Order No. G-13-98. BC Hydro implemented the tariff amendments with effective from April 1, 1998.

Two of the Commission's ten guidelines are germane:

1. The Commission recommends that evaluation of system extensions be based on a discounted cash flow evaluation method that includes, to the extent feasible, all incremental costs and benefits associated with a particular system extension over a time period long enough to consider the full impact of the extension. The Commission also recommends that, as a general principle, the costs of system extensions be allocated to those customers who cause them.

5. The Commission recommends that the costs and benefits to be considered in the analysis of proposed system extensions include pre-construction estimates of the following:

   (a) construction costs of the system extension;

   (b) associated incremental system improvement costs, where these can be identified and assessed in a cost-effective manner;

   (c) associated incremental operation and maintenance costs, where these can be identified and assessed in a cost-effective manner;

   (d) net costs of connection (i.e., cost of connection less connection fees);

   (e) net revenues from the system extension (i.e., customer payments less revenues to provide for commodity purchases and upstream transmission charges); and

   (f) a reasonable consideration of externalities (for the social perspective evaluation)" (SET Guidelines, p. 31).

In its October 29, 2004 Decision concerning BC Hydro's 2004/05 to 2005/06 Revenue Requirements Application the Commission noted that "[A] System Extension Test based on the BCUC Extension Policy implemented in 1998 currently guides BC Hydro's customer driven projects. When cross-examined by Terasen as to whether BC Hydro has been properly calculating the full future cost of providing service for customer attachments, BC Hydro testified that some cost factors such as the long-term price forecast and the "Cost of Electricity" as defined in the Electric Tariff page A-5-2 are probably different as BC Hydro has not updated the inputs to the SET tests since the tariff came into effect on April 1, 1998". Since BC Hydro had taken the position that a rate design hearing was the more appropriate forum to look at all the electricity tariffs for electricity and other costs, the Commission directed BC Hydro to periodically update the input factors when evaluating customer driven projects (Decision at pp. 165 and 167).

Accounting and Ratemaking Treatment

Typically utilities account for the amounts received as extension fees received from their customers as "Contributions in Aid of Construction" ("CIAC") and amortize them at the same rate as the assets which the CIAC helped finance. BC Hydro is no different in its accounting treatment for CIAC. For rate making purposes, however, HC2 requires that BC Hydro's CIAC be considered equity upon which it earns a return based on the benchmark low-risk utility's return on equity adjusted for income tax which is currently 12.05 percent.

A Terasen policy panel member testified that Terasen deducted CIAC from its rate base for rate making purposes (T9:1603). BC Hydro provides a calculation of the net present value of the revenue requirement over 40 years of an extension costing $10,000 in two cases, one where there is no contribution by the customer and a second case where there is a contribution by the customer of 100 percent of the cost of the extension. This demonstrates that in the case where there is no contribution by the customer the PV of the revenue requirement discounted at 4.65 percent is $10,000, whereas in the case where the customer is required to make a full contribution the PV of the revenue requirement is $14,446 (Exhibit B-55).

5.2.3 BC Hydro's Rationale for Change

BC Hydro states that it is proposing to simplify and improve the transparency of its distribution extension policy, including a simplified approach to determining the amount of investment that BC Hydro will make toward a new extension (Exhibit B-1, p. 5).

BC Hydro testified as to the three principles which prompted it to propose to change its methodology: "… the first one being fairness in terms of the price charged new customers with respect to the Heritage Contract and their entitlement to the average cost of energy. The second objective was simplicity, to provide an extension policy that's much simpler and more transparent to our customers. And the third objective was to try and keep the overall level of customer contribution as a percentage of extension costs at about the same level" (T5:774-5).

BC Hydro states that if it were to use the current marginal cost of generation in the determination of the investment that it would make toward an extension, the expected incremental revenue would be lower than the estimated incremental costs of supplying the new load and that, as a result, new customers would be required to pay for the entire cost of extensions. This approach would effectively deny new customers any benefit from Heritage Resources contrary to the principles of the Heritage Contract, since new customers would effectively be paying (through a combination of their rate and their extension fee) the incremental cost of energy. Furthermore, this approach would not be fair to future new customers, since previous generations of new customers have benefited from a contribution by BC Hydro toward the cost of new extensions (Exhibit B-1, p. 56).

In BC Hydro's determination of the net margin under the current extension policy, all incremental costs are deducted from the revenue expected from the customer. The customer is then charged a contribution equal to the present value of any negative net margin. Since the current marginal cost of generation is greater than the revenue expected from a new customer, if the existing policy were updated to reflect the current marginal cost of generation, all customer contributions would exceed the cost of the extension. New customers would therefore contribute toward upstream costs, effectively denying new customers any benefit from Heritage Resources (Exhibit B-3, BCUC 1.45.1).

5.2.4 BC Hydro's Proposal

BC Hydro considered the matter of sending appropriate price signals to its customers and states that its proposed method would result in its maximum allowance being the same regardless of a customer's electricity consumption and whether or not the home has electric heat. It states that since the electrical infrastructure required to provide service to electrically heated homes is more expensive than that required to provide service to non-electrically heated homes, its proposed method would result in a customer with electric heat paying a higher extension fee than a customer without electric heat and that charging customers with electric heat a higher extension fee than customers without electric heat is consistent with its objective of sending efficient pricing signals, and encouraging customers to make energy efficient choices (Exhibit B-1, p. 58).

BC Hydro states that in order to simplify its distribution extension policy in a manner consistent with the SET Guidelines and to maintain average BC Hydro contributions comparable to previous generations of new customers, it is proposing to base the maximum allowance in a new distribution extension on the present value of the expected distribution demand-related revenue over a 20-year period. Since its rates are bundled and do not separately identify the portion of the rate that recovers distribution demand-related costs, BC Hydro proposes to use, as a proxy for distribution demand-related revenue, the present value of the distribution demand-related costs assigned to each rate class in the FACOS of its Application, from which it derives the following maximum allowance levels toward a distribution extension for each rate class:

Table 5-1
Maximum BC Hydro Contribution

Residential	$1,900 / customer
Gen Service < 35 kW	$425 / kW
Gen Service > 35 kW	$425 / kW
Irrigation	$300 / kW
Street Lights	$110 / fixture

Source: Exhibit B-1, p. 57, Table 7

BC Hydro states that although its Small General Service customers are not demand-metered, it considers it appropriate for BC Hydro's allowance to vary with the size of the customer's load and therefore, proposes to use the same maximum contribution for its Small General Service customers as for its Large General Service customers (Exhibit B-1, p. 57).

BC Hydro states that other aspects of its proposal include:

- that the maximum allowance levels above may be reduced if an applicant is expected to cease taking service or to substantially reduce its load within the first 10 years and if future customers are not expected to connect to the extension;
- system improvement costs will only be considered for new loads greater than 500 kVA;
- if a customer requests optional facilities that are not reasonably required to provide service to the customer, then the customer would be required to pay the full cost of such facilities as in the current tariff; and
- providing a transition from the current to the proposed method of calculating the extension fee payable by a customer, by BC Hydro charging the customer the lower of the extension fee payable under the two methods for the three-month period from April 1, 2008 to June 30, 2008.

(Exhibit B-1, pp. 57-58)

Of the derived allowances, only the Residential Allowance was addressed by Intervenors in this proceeding. BC Hydro states that it calculated the maximum Residential Allowance as the amount it would invest in a new distribution extension using the present value of the expected distribution demand related revenue requirement over a 20 year period using a discount rate of 6 percent.

BC Hydro testified that its maximum Allowance calculation was sensitive to two main variables: the number of years and the discount rate, as well as being affected by the choice of allocation factor used to allocate distribution costs between demand and customer (T8:1279). It provided two tables setting out the Allowance under a range of variables under both the 50/50 and the 75/25 demand/customer allocation. The following table summarizes BC Hydro’s study:

Table 5-2

	75/25 Allocation				50/50 Allocation			
Rate	**10 years**	**20 years**	**30 years**	**40 years**	**10 years**	**20 years**	**30 years**	**40 years**
4%	1,350	2,250	2,850	3,300	900	1,500	1,900	2,200
6%	1,200	1,900	2,300	2.500	800	1,250	1,500	1,650
8%	1,100	1,650	1,850	1,950	750	1,100	1,250	1,300

(Derived from Exhibit B-65)

5.2.5 Impact of the Proposal

BC Hydro states that it performed a random sample of 18 electric heat extensions done in F2006 to illustrate the effects of the new policy on electric space heated extensions.

Extension fees collected for each extension ranged from $0 to $65,125 under the existing policy and from $0 to $98,267 under the proposed policy. Total extension fees collected under the existing extension policy were $170,734 (average $9,485 per extension) compared to $289,034 (average $16,057 per extension) that would be collected under the proposed policy. Based on this sample, the extension fee per extension is $6,572, an average of 69 percent greater under the proposed policy than under the existing policy (Exhibit B-18, Terasen 1.18.4 Revised).

BC Hydro states that, based on a one month sample of 95 Residential, 49 Small Commercial, and 46 Large Commercial extensions, the expected impact of the proposed extension policy will be a 3 percent increase in total Contribution in Aid from customers (Exhibit B-42).

In response to an IR from Terasen, BC Hydro calculated the customer contribution required for a hypothetical 42-lot residential subdivision development, where the variables were underground and overhead service and electric and non-electric heat. The results of the analysis were given for BC Hydro's existing customer contribution policy; its existing policy with $88/MWh as the incremental cost of energy, and its proposed policy were as follows:

Table 5-3

	Customer Contribution Existing Policy (GST not included)	Customer Contribution Existing Policy With Cost of Electricity of $88/MWh (GST not included)	Customer Contribution Proposed Policy (GST not included)
U/G Extension (non electric heat)	$53,836	$206,931	$49,054
U/G Extension (electric heat)	$34,351	$287,186	$66,831
O/H Extension (non-electric heat)	$29,063	$177,553	$19,446
O/H Extension (electric heat)	$15,624	$252,698	$24,510

Note: Costs include service connection charges, assuming a 100 amp service connection for non-electric
heat customers and a 200 amp service connection for electric heat customers.

Source: Exhibit B-7, Terasen 2.7.1

BC Hydro testified that it had no evidence as to whether its current and proposed system extension policies would be material in terms of the other development fees and levies that are imposed on the development of a residential subdivision, or whether either its current or proposed extension policy would influence the developer's behaviour (T7:1201).

5.2.6 Terasen's Proposal

Terasen states that extension policies can be used to achieve various objectives, such as balancing the interests of existing customers against those of new customers, or promoting or discouraging energy use in a particular region or end use application, and that extension policies should be focused on sending appropriate price signals to builders and developers to encourage the most efficient energy source in new dwellings for space and hot water heating. Terasen proposes changes to BC Hydro's SET policy, which are aimed at avoiding electric load growth related to space and water heating and thus reducing the growth in BC Hydro's system winter peak.

Terasen retained EES to review and summarize several SET methodologies. EES found that, among those methodologies it reviewed, BC Hydro's proposed methodology results in BC Hydro having the highest Allowance per customer and the lowest contribution made by builders and developers.

Terasen believes that this is not the appropriate price signal to developers faced with a choice between gas and electricity for space and water heating. Terasen recommends a SET approach that considers the incremental distribution costs and results in an allowance or credit of $1,300 per residential customer (as opposed to $1,900 per residential customer under the BC Hydro proposal), which will require larger contributions on the part of a developer or builder to install electric space or water heating.

EES states that BC Hydro's proposed extension credit still suffers from a theoretical standpoint in that it is predicated on expenses, and not the amount of investment covered in the applicable retail rate, and observes that "[C]alculating credits based upon a long range forecast is ripe with assumptions and forecast error" (Exhibit C7-4, p. 25).

EES notes that while it is correct that BC Hydro's proposed extension Allowance is a function of investments in its facilities due to factors such as depreciation and cost of capital, the proposed extension credit also includes O&M expenses. The extension credit is supposed to offset capital costs not collected through present rates. Since the proposed extension credit includes O&M expenses, the new connection customer is getting a credit for future O&M expenditures as well (Exhibit C7-5, BCUC 1.22.1).

EES proposes a system extension methodology where the level of investment which is provided to each new customer is predicated on the amount of investment in distribution poles, conductors, and transformers covered in the applicable retail rate. Any investment in poles, conductors and transformers needed to provide service to a new customer in excess of this investment level would be paid for upfront as a capital contribution by the new customer. The principles for distribution system extension charges are that they should be fair to all and collect enough from a new customer to hold harmless all other customers from the incremental costs of supplying new localized distribution poles, conductors and transformers. The mechanics for calculating an extension charge given these higher principles is to determine how much capital for distribution poles, conductors and transformers is covered by the standard retail tariff , the allowance, then charge a new customer the actual cost of new poles, conductors and transformers needed to provide service less the allowance level. The methodology is simple to calculate, can be updated each time a Cost of Service Study is performed and holds existing customers harmless from the incremental cost of growth in pole, wire and transformer costs.

Based on its allocation of net plant in service in BC Hydro's integrated areas as at March 31, 2006 EES calculates that the investment in distribution assets allocated to the Residential rate class was on a per customer basis:

Table 5-4

Methodology	per customer net
75/25 Demand/customer	$1,210.88
50/50 Demand/customer	$1,323.48

(Derived from Exhibit C7-4, EES 7, pp. 9-14)

5.2.7 Consistency with SET Guidelines

BC Hydro considers the consistency of its proposed Distribution Extension Policy with the use of full incremental costs as recommended by the Commission's SET Guidelines and states that the proposed maximum amounts that it would invest in a new distribution extension are based on the present value of the expected distribution demand-related revenue over a 20-year period and that this approach is consistent with the use of incremental costs and the principle that all customers should benefit from the Heritage Resources. BC Hydro states that by excluding generation-related revenues, it has implicitly assumed that all customers should be responsible for the average cost of generation, consistent with the principle that all customers should benefit from the Heritage Resources. By excluding transmission-related revenues, BC Hydro states that it has implicitly allocated all new customers a portion of incremental transmission costs. BC Hydro states that by ignoring distribution demand-related revenues after year 20, it has implicitly allocated all new customers a portion of incremental upstream distribution costs; and that by excluding customer-service related revenues, it has implicitly allocated all new customers a portion of incremental customer-service related costs (Exhibit B-3, Terasen 1.16.1).

BC Hydro states that under its current tariff, the estimated construction cost for all new distribution extensions includes SI costs but that for the sake of simplicity and improved transparency, it is proposing that system improvement costs only be considered for new loads greater than 500 kVa.

BC Hydro reviewed the fairness of this proposal and states that the proposed maximum amounts that it would invest in a new distribution extension were based on the present value of the expected distribution demand-related revenue over a 20-year period. By only including the first 20 years of distribution demand-related revenue and by not including any transmission-related revenue, BC Hydro has implicitly allocated all new customers a share of upstream distribution and transmission SI costs.

It notes that, in a case where the SI costs are extraordinary (such as the requirement for a new substation), this implicit recognition of incremental upstream costs may not be sufficient. Since such extraordinary incremental costs are only likely to occur as a result of the addition of very large loads, for administrative simplicity and transparency a 500 kVa threshold is proposed (Exhibit B-3, BCUC 1.45.5).

5.2.8 Intervenor Arguments

Other than Terasen and FortisBC, no Intervenor takes a position on BC Hydro's proposed changes to its SET. FortisBC submits that it supports a move away from BC Hydro's current SET. It says that BC Hydro's new proposal is an improvement over the past methodology in terms of ease of use; is an appropriate cost based methodology and is consistent with "generally accepted rate making principles". FortisBC submits that:

> "By using the current SET methodology, adjusted for the marginal cost of power, new customers would in effect be pre-paying the difference between the marginal cost of power and the embedded cost of power, which includes a proportionate share of the Heritage Contract. Adherence to the SET does not provide new customers with access to the benefits of existing resources" (FortisBC Argument, pp. 4).

No Intervenor challenges BC Hydro's assertion that its proposed changes to its SET conform to Commission Guidelines.

In its Argument, Terasen considers BC Hydro's methodology and submits that BC Hydro's proposed investment level is based on a 20-year estimate of the distribution demand-related revenue to be collected from the customer and observes that this revenue consists of two components: revenue collected from the customer to pay for annual distribution O&M expenses, and revenue collected to pay for capital expenditures. Each year BC Hydro incurs costs to operate and maintain its distribution system, which are recovered through rates. Terasen submits that it is illogical that new customers are provided an allowance, which is above and beyond the revenue collected to pay for capital expenditures and that if BC Hydro wants to include all distribution related revenue in its investment limit calculation, then the costs should include not only the capital cost of the extension, but also the projected 20-year annual distribution O&M expenses. Terasen submits that the preferable approach is for the allowance to be based only on the revenue collected to pay for capital expenditures (Terasen Argument, para. 83).

In its Reply, BC Hydro acknowledges that the distribution-related revenue used to determine its proposed allowances toward new distribution extensions includes revenues related to the recovery of operating costs, but submits that it used only 20-years of distribution-related revenue in its calculation rather than the entire life of approximately 40 years. It submits that using a 20-year period rather than the entire life of 40 years offsets the fact that the distribution-related revenue includes revenues related to the recovery of operating costs (BC Hydro Reply, p. 30).

Terasen takes issue with the concern identified by BC Hydro characterized as intergenerational inequity – where previous connecting customers have benefited from a contribution that would now change -- and submits that BC Hydro's logic is not persuasive. Terasen submits and that the concept of neutrality does not exist elsewhere in the "real world", where inflation is occurring due to market forces. It also submits, and that there is no legislated requirement that BC Hydro must maintain customer contributions at the same level as under the current SET, or regulatory principle that stipulates that new customers should always be able to pay the same amount for connections as prior customers (Terasen Argument, paras. 84, 85).

In its Reply, BC Hydro submits that Terasen has misunderstood its concern for intergenerational equity, and that BC Hydro's position is that past and present generations of customers should be treated consistently unless there is some cost causation reason for doing otherwise, and that there is no cost causation justification for a material change in the overall level of contributions collected from customers. BC Hydro also submits that maintaining the same overall level of contributions also benefits current customers, since contributions are treated as equity upon which BC Hydro is allowed to earn a return (BC Hydro Reply, p. 31).

Terasen submits that in order to send an effective price signal regarding fuel choice, there should be a significant differentiation between the total amount paid by new customers to connect for electric space or water heating as compared to those new customers without electric space or water heating. The pricing should also be set with reference to the cost of connecting to alternative fuel sources for space and water heating; so long as it is cheaper for a customer to connect to BC Hydro's system for electric space and water heating, than to install an alternative fuel source for those applications, the rational price response would be to favour electric space and water heating. Nevertheless, BC Hydro's proposed SET, and the pricing, was not established with any reference to the cost of the customer connecting to an alternative fuel source for heating, either natural gas or some other fuel source. According to Terasen this is a fundamental flaw with the proposed RDA. The SET and connection charge proposed by Terasen will send more appropriate price signals to the individuals – primarily builders and developers - who make the decision as to whether the install electric heating, natural gas heating, or some other alternative heating source (Terasen Argument, para. 81).

Terasen submits that it has not proposed to recover the full incremental cost of new supply but has settled on $1,300, leaving the customer to cover an additional approximately $600 for the extension over and above BC Hydro's proposal, which would be an additional price signal per connection for builders and developers, whose behaviour will be influenced by the up-front costs, and that the remainder of the price signal it proposes arises from proposed increase to the connection charge (Terasen Argument, para. 86).

Commission Determination

While the Commission Panel accepts BC Hydro's submission that its present SET policy is a complex policy which has not been, in BC Hydro's own admission, administered in accordance with its Terms and Conditions using up-to-date cost data, it notes that the present SET policy nevertheless represents a policy which this Commission has approved and found to be in accordance with its SET Guidelines. The Commission Panel also notes that BC Hydro's present SET policy appears to be inconsistent with BC Hydro's stated policy of setting rates on a postage stamp basis.

The Commission Panel accepts the evidence that the strict application of the existing policy can result in customers being asked to contribute to BC Hydro an amount greater than BC Hydro's cost to extend its system to provide them service. The Commission Panel notes FortisBC's submission that "adherence to the (existing) SET does not provide new customers with access to the benefits of existing resources" and notes that no Intervenor challenged BC Hydro's assertion that new customers were entitled to share in the benefits of existing Heritage Resources.

The Commission Panel considers that BC Hydro's concern for intergenerational equity has influenced its selection of allowance level. Since, by BC Hydro's own admission, it has not complied with its own SET policy or with the Commission's direction to do so, the Commission Panel cannot accord BC Hydro's concern for intergenerational equity any weight.

The Commission Panel does not accept the characterization in HC2 of BC Hydro's accumulated contributions as "equity" for rate making purposes as relevant in establishing SET policies.

The Commission Panel has considered the regulatory background to the Commission's 1996 generic hearing into utility system expansions. Events that have taken place subsequent to1996 must be considered by the Commission when setting BC Hydro's rates. These events include HC2 and the Heritage Contract, and in this regard the Commission Panel notes the notes the language of section 5 of HC2.

> **"Determining the cost of energy**
>
> **5** In setting the authority's rates, the commission
>
> > (a) must treat the heritage contract as if it were a legally binding agreement between 2 arms-length parties,
> >
> > (b) must determine the energy required by the authority to meet its domestic service obligations and must determine the cost to the authority of the portion of that required energy that is in excess of the energy supplied under the heritage contract,
> >
> > (c) may employ any mechanism, formula or method referred to in section 60 (1) (b.1) of the *Utilities Commission Act*, and
> >
> > (d) unless a different mechanism, formula or method is employed under paragraph (c), must ensure that electricity used by the authority to meet its domestic service obligations is provided to customers on a cost-of-service basis."

The Commission Panel finds that the language of subsections 5 (a) and 5 (d) requires that the Commission set BC Hydro's SET rate on the basis that power will be made available to its customers on a cost of service basis and that it should set aside the effect of incremental cost of energy in its calculation on the grounds that energy will be a flow-through from BC Hydro (Generation) to BC Hydro (Distribution). As a result, the methodology proposed by BC Hydro complies with the Commission's SET Guidelines.

As well, the Commission Panel is of the opinion that the pending introduction of residential inclining block rates, (as dealt with at Section 4.0 above), where the final block is priced off the marginal cost of energy, will ensure that BC Hydro's proposal complies with the Commission's SET Guidelines.

While the Commission Panel agrees that BC Hydro's proposed methodology is a suitable way of approaching the calculation of its maximum allowance and complies with the Commission's SET Guidelines, the Commission Panel does not agree with BC Hydro's proposed application of the methodology. The Commission Panel is persuaded by Terasen's argument that the more correct approach is to calculate the PV of only the depreciation and return portion of the distribution demand revenue requirement.

Accordingly, BC Hydro's proposed SET policy is not approved. The allocation methodology to be applied is to be the Commission Panel's finding of 65 percent demand/35 percent customer. The calculation is to cover the 20 years proposed by BC Hydro, and is to use BC Hydro's nominal weighted average cost of capital of 8 percent, as recommended by the Guidelines and BC Hydro's existing SET policy, rather than BC Hydro's proposed rate of 6 percent. BC Hydro is ordered to recalculate its allowance levels in Table 5-1 of this Decision using the methodology set out above, and file the recalculated allowance levels within 60 days of the Order issued concurrently with this Decision.

BC Hydro's proposal to charge the customer the lower of the extension charge under its existing SET Policy and the above extension policy from April 1, 2008 until June 30, 2008 is approved.

5.3 Minimum Connection Charges

5.3.1 Fuel of Choice

This Section discusses the issue of whether there is a fuel of choice in the 2007 Energy Plan, and reviews the evidence led by Terasen, which attempts to quantify the impact of new customers opting for electric space and water heating.

When addressing promotion of energy efficiency and alternate energy in its 2007 Energy Plan, the Provincial Government states the following:

> "It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity, at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas (Exhibit B-3, ESVI 1.6.1, Attachment, p. 21)".

The Commission Panel Hearing Issues List item 1.4 raises the following two questions regarding this topic:

- Is there a fuel of choice in the 2007 Energy Plan?
- Should the 2007 RDA address the objective of the right energy source for specific end use? (Exhibit A-23, p. 1)

BC Hydro in its comments on the Issues List clearly articulates its position by stating that the 2007 Energy Plan is ambiguous on fuel choice, and the 2007 RDA should not be the vehicle to resolve the issue (Exhibit B-26, p. 1).

In cross-examination of the BC Hydro panel, Terasen presented a copy of a page from BC Hydro's website encouraging its customers to use energy resources efficiently for home heating: "It's important to match your energy source to its best use. Electricity is best suited for lighting and powering our appliances and televisions, whereas natural gas is ideal for space and water heating" (Exhibit C7-10, Tab 4). BC Hydro states that from time to time since the 1980's it has encouraged natural gas for space heating, and that the referenced statement was first placed on its website in 2005 (Exhibit B-31).

BC Hydro states that it has an objective of providing price signals that encourage customers to make energy efficient choices, and that in the past, it encouraged customers to use natural gas instead of electricity for space heating, based on economic and environmental considerations. BC Hydro is reviewing this practice in light of the 2007 Energy Plan (Exhibit B-3, Terasen 1.3.1).

To further clarify its corporate policy, BC Hydro in its Opening Statement states: "Where government policy gives rise to different interpretations on a significant issue, as in the example of using fuel-switching to meet conservation goals, BC Hydro believes the appropriate response is neutrality, thereby allowing government an opportunity to clarify" (Exhibit B-24, p. 3).

In its Opening Statement Terasen states that it participated actively in the RDA proceeding to ensure that the rate structure and policies of BC Hydro relating to connection of new customers and expansion of the BC Hydro distribution system do not result in the choice of electricity for space and water heating when it would be more appropriate to choose natural gas or an alternate form of energy. Terasen further stated that the RDA fails to provide the correct price signals to persons making decisions on the choice of electricity or another energy source for space heating and water heating purposes (T3:299).

Terasen also stated that the heritage electric power is too valuable a resource to squander on the heating of houses and the heating of water, when there are more appropriate alternate energy sources to supply those requirements (T3:301). Terasen believes that there are good and cogent reasons for natural gas to be the preferred energy source for space and water heating. Terasen further stated that the proposals in the RDA will intentionally or un-intentionally cause electricity to be chosen primarily because the true cost of that use of electricity will not be seen by the persons making the choice (T3:301-302). Finally, Terasen also pointed out that use of natural gas for space and water heating is consistent with the Government's objective to reduce greenhouse gas (GHG) emissions (T3:304).

BC Hydro testified that more work must be done to assess the issue of fuel switching and that the Government's objectives of electricity conservation and a reduction in GHG can lead to conflicting outcomes. The Conservation Potential Review ("CPR"), expected to be completed in the fall of 2007, is addressing fuel switching among other topics. The CPR forms the basis of the DSM Plan, which again is a component of the Long Term Acquisition Plan ("LTAP") (T5:700-704). BC Hydro expects to file its next LTAP in the Spring of 2008 (Exhibit B-73).

BC Hydro testified that approximately 19 percent of its residential customers use electricity to heat their homes and approximately 36 percent use electricity to heat water. It produced a table that computed its 2006 appliance saturation and use rate which showed the following saturation and use for electric heating appliances:

Table 5-5

End use	Share	Unit Energy Consumption (kW.h/yr)
Electric Furnace	2.42%	13,672
Heat Pump	1.50%	6,839
Base Board	14.95%	13,535
Total Electric Heat	18.87%	12,345 (weighted average)
Water Heater	35.5%	3,344

(Derived from Exhibit B-76)

BC Hydro testified that an average customer with electric heat consumed 40 percent more power in a year than did an average customer who did not use electric heat. Currently BC Hydro’s aggregate residential load with electric heat is 4,461 GW.h/year, and 20 percent of new customers are forecast to use electric heat (T7:1137).

Terasen filed evidence which attempts to quantify the impact of BC Hydro’s forecast of customers choosing to heat their new homes’ space and water using electricity and forecasts that by 2020 an additional 66,000 customers will use electricity to heat their homes and an additional 115,000 customers will use electricity to heat their water and that the incremental requirement for electricity in 2020 will be 1,267 GW.h per year (Exhibit C7-17). Terasen estimates that the impact of this on existing customers is a negative PV per additional customer who chooses to use electricity to heat his or her space and water of $9,600 and $2,300 respectively (Exhibit C7-20).

BC Hydro argues that any Commission orders requiring BC Hydro to discourage the use of electric heat, which are based on the “rough-and-ready” quantification possible in the RDA proceeding could lead to expensive and unworkable policies that hinder rather than assist in the implementation of the Energy Plan. Therefore, BC Hydro submits, the Commission ought to reject Terasen’s underlying policy premise as a factor to consider in assessing the 2007 RDA (BC Hydro Argument, p. 12).

Terasen submits that “choosing the right fuel for the right activity at the right time should have been a driver of BC Hydro’s rate design proposals in this foundational RDA regardless of the Energy Plan. Efficiency should be one of the guiding principles of any rate design, irrespective of government policy. BC Hydro’s failure to address the role efficient fuel choices on the part of new customers can play in load avoidance will make it much more difficult to meet the objectives of the Energy Plan in the future” (Terasen Argument, p. 3).

BCOAPO argues that Terasen’s proposal is based on the assumption that the use of natural gas rather than electricity is self-evidently more consistent with conservation and GHG policy, and that the Commission has made no determination as to the correctness of that assumption (BCOAPO Argument, p. 23).

The CEC submits that there is not enough evidence in this proceeding to address this issue and it may best be dealt with in subsequent rate proceedings (CEC Argument, p. 36).

In Reply, BC Hydro agrees with the submissions of BCOAPO (BC Hydro Reply, p.32).

Commission Determination

The Commission Panel commends Terasen for its initiative in leading evidence both concerning the use of electricity for space and water heating in BC Hydro’s service area, and concerning the potential growth in demand for electric space and water heat that BC Hydro is forecasting. The implications of the growth in demand were among the reasons that led the Commission Panel to encourage and guide BC Hydro to implement an inclining block residential rate, so that customers receive the correct pricing signal in this regard. The Commission Panel agrees with Terasen that the use of natural gas (as opposed to electricity) for space and water heating in B.C. will make additional energy available to displace coal or gas-fired generation at the margin in the Pacific Northwest.

The Commission Panel does not, however, consider that it is the role of the Commission to determine governmental policy in respect of fuel choice for residential space and water heating. The Commission Panel is of the view that BC Hydro and Terasen must resolve with the Provincial Government any "ambiguity" they perceive in the 2007 Energy Plan. Accordingly, the Commission Panel makes no determinations in this regard.

5.3.2 BC Hydro's Proposed Minimum Connection Charges

BC Hydro states that applicants for new service are required to pay a service connection charge, which includes the service connection and the meter, and that for typical single phase installations in Rate Zone I, the Service Connection charge is equal to the minimum connection charge as set out in its Schedule of Standard Charges. For all other service connections and a meter, the Service Connection charge is based on the estimated construction cost of the service connection including the installation cost of the meter.

BC Hydro stated that the minimum connection charges set out in the Schedule of Standard Charges are based on its costs for typical installations and it proposes to update the minimum connection charges based on its current costs for typical installations, as detailed in Appendix H to the Application. BC Hydro proposes the following minimum connection charges for single phase installations in Rate Zone I.

Table 5-6

Table 8 – Proposed Minimum Connection Charges

	Existing Fee	**Proposed Fee**
Overhead - 100 Amp	\$312.00	\$463.00
Overhead - 200 Amp	\$372.00	\$496.00
Overhead - 400 Amp	\$696.00	\$798.00
Underground - 100 Amp	N/A	\$605.00
Underground - 200 Amp	N/A	\$855.00
Additional Meter - Same Trip	\$25.00	\$23.00
Additional Meter - Separate Trip	\$77.00	\$92.00

Source: Exhibit B-1, p. 60, Table 8

BC Hydro states the Schedule of Standard Charges in its existing Terms and Conditions does not include minimum connection charges for underground installations, and that since underground installations now account for the majority of new single phase installations, it proposes to add fees for underground installations to its Schedule of Standard Charges (Exhibit B-1, pp. 59-60).

5.3.4 The Terasen Proposal

Terasen states that connection policies can be used to achieve various objectives such as balancing the interests of existing customers against those of new customers or promoting or discouraging energy use in a particular region or end use application, and should be focused on sending appropriate price signals to builders and developers to encourage the most efficient energy source in new dwellings for space and hot water heating. Terasen proposes changes to the customer connection policies, which are aimed at avoiding electric load growth related to space and water heating and will be aimed at reducing the growth in BC Hydro's system winter peak.

Terasen states that as neither the BC Hydro nor EES approach to the SET considers the incremental cost of supply to serve the space and water heating load, it believes customer connection policies should be considered in a complementary fashion with the SET, and with the aim of achieving goals of the 2007 Energy Plan. Terasen states that there should be a significant differentiation between the connection charge for new customers with electric space heating as compared to those new customers without electric space heating and that the connection charge proposed by BC Hydro for a 200 Amp service connection of only $33 more than the charge for a 100 Amp service does not provide the necessary significant differentiation. Terasen observes that it is generally the case that customers (primarily developers and builders) who intend to install electric space heating will typically require a 200 Amp or greater service, whereas customers without electric space heating will typically require a 100 Amp service. It is clear that BC Hydro's proposed customer connection charges, coupled with its proposed SET will do little to influence the energy choices for space and water heating that are being made by builders and developers on behalf of energy consumers or recognize the true cost of electric space heating for new customers (Exhibit C7-4A, p. 9).

Accordingly, Terasen proposes that the charge to connect a new customer intending to use electric space heating include a $2,000 surcharge in addition to the service connection charges proposed by BC Hydro, but which would not be applicable in the event that the new customer proposed to use electricity for water heating purposes only. Terasen states that the $2,000 incremental charge represents a small offset of the negative PV of $9,600 for space heat and $2,300 for water per new customer over a 20 year period, and will be a material price signal to builders and developers and will result in the avoidance of new additional electric space and water heating load (Exhibit C7-4, pp. 9-10).

Terasen states that using scarce and valuable electricity for these end uses is not consistent with the 2007 Energy Plan which advocates (at page 21) using “the right fuel for the right activity at the right time” and that failing to discourage electric space and water heating will also make the Energy Plan goals of electricity self-sufficiency by 2016 and meeting 50 percent of BC Hydro’s load growth by conservation by 2020 more difficult to achieve. Space and water heating end uses are more appropriately served by natural gas and alternative energy technologies.

Terasen states that it adopted 200 Amp service as a proxy, which would capture a significant portion of electric space and water heating. As with any proxy, it notes that there will be circumstances where the intended outcome is not achieved but states that it would support the use of any mechanism that could be used in place of a proxy to establish with greater accuracy whether electric space and water heating is being installed.

Terasen states that it further derived the $2,000 surcharge from an approximation of the additional upfront capital costs that a builder or developer would experience to fit a house for natural gas service. As might be expected, these additional capital costs vary with dwelling size and other factors but $2,000 is a reasonable proxy (Exhibit C7-5, BCUC 1.6.1.2).

BC Hydro submits that, the $2,000 surcharge is clearly not based on BC Hydro’s costs and is therefore not consistent with the SET Guidelines (BC Hydro Argument, p. 61).

BC Hydro submits that Terasen acknowledged that the $2,000 surcharge represents a portion of the avoided electricity supply costs; hence, the $2,000 surcharge effectively represents a prepayment by the new customer of a portion of the benefit of the Heritage Resources that the new customer would otherwise receive. In addition, the 2007 Energy Plan does not explicitly contemplate the fuel-switching incentive proposed by Terasen. With BC Hydro's new self-sufficiency requirement and the requirement that all new generation be GHG emission-free, natural gas may not be the right choice for home heating requirements. At best, BC Hydro submits that any fuel-switching incentive would be premature. Given all of the above, BC Hydro submits that Terasen's proposed surcharge on 200 amp or greater services for electric space heating should be rejected by the Commission (BC Hydro Argument, pp. 61-2).

Terasen cites Guideline No. 6 of the SET Guidelines which states: "The Commission recommends that Utility connection charges move toward recovery of the full cost of the service connection up to but not including the meter, and include incremental costs such as applicable system improvement costs. In addition the Commission recommends that the Utilities come forward with options for connection fees that send an appropriate signal about the net social costs of less efficient energy use," and Terasen submits that this is precisely what it is proposing (Terasen Argument, p. 37).

BCOAPO submits that Terasen's proposal can only be fairly described as a penalty, and is based on the assumption that the use of natural gas rather than electricity for heating load is self-evidently more consistent with conservation and GHG policy – overlooking the fact that, according to the 2007 Energy Plan, incremental electricity generation will be 90 percent "clean," and therefore presumably less carbon intensive than burning natural gas for space and water-heating. BCOAPO submits that there has been no determination by the Commission that Terasen's foundational assumption is correct, and the record of this proceeding does not provide any basis for any determination either way on the matter.

BCOAPO further submits that the $2,000 connection penalty would violate section 59 of the UCA. and that Terasen has not attempted to justify the penalty as a "fair and reasonable charge" for being connected to the grid and that the "nature and quality" of the service an electricity customer receives is the same regardless of whether it will be used for heating applications, and yet the rate would differ dramatically. "Rather, Terasen promotes the penalty as a sort of prod, to coerce customers into switching fuels. The Commission has no jurisdiction to approve it" (BCOAPO Argument, p. 23).

FortisBC submits that under generally accepted rate making principles, connection charges are primarily based upon the cost of service to customers and that this methodology may be altered, but only when there is a compelling reason to do so. Changing the methodology for determining connection charges from a cost of service basis to creating price signals for fuel switching should only occur after significant study and stakeholder input has taken place (Fortis BC Argument, para. 17).

In Reply BC Hydro submits that BCOAPO may be correct in its argument that there is no basis in the UCA for the establishment of rates that are meant to punish customers, but accepts that the specific arguments raised by Terasen in support of its connection charge proposals are policy-based and not punitive in the sense that they could not be ordered by the Commission (BC Hydro Reply, p. 32).

Commission Determination

The Commission Panel has considered BCOAPO's submission that Terasen's proposed connection fee would violate the UCA and notes that the SET Guidelines appear to encourage utilities to propose just such connection charges, and concludes that such a proposed connection fee would not violate the UCA. However, the Commission Panel is not convinced at this time that Terasen's proposal to impose a connection fee surcharge to those customers proposing to use electricity for space heating is appropriate. There is no evidence before the Panel that such a surcharge will cause builders and/or developers to alter their construction plans. The Commission Panel is of the opinion that the correct method to send appropriate price signals to builders, developers and potential buyers is by way of the electric tariff itself and that properly designed inclining block residential rates will send the appropriate price signals and result in the most efficient fuel choice. Furthermore, if the final block of an inclining block residential rate structure reflects the marginal cost of acquiring power (currently estimated by BC Hydro and Terasen at $88 per MW.h) then Terasen's calculations of the negative PV of $9,600 and of $2,300 per new customer choosing electric space and water heating respectively become moot.

If BC Hydro should be informed by its 2007 Conservation Potential Review and by Stakeholder Engagement that a cost effective method of avoiding growth of residential demand and energy is to actively discourage the use of electricity for space heating by the imposition of connection fees based on other than costs of service, the Commission will consider such an application at that time.

The Commission Panel determines that BC Hydro's proposed Schedule of Service Connection charges is appropriate, and is so approved.

5.4 Other Substantial Changes

BC Hydro proposes the following substantive changes to its Terms and Conditions:

- Prepaid Metering;
- Security Deposits;
- Minimum Reconnection Charges; and
- Miscellaneous Charges.

5.4.1 Prepaid Metering

BC Hydro states that it introduced a prepaid metering option in 1995 as a means of reducing meter reading and collection costs in remote communities but that a pilot project did not yield the expected benefits and that no remote community has ever requested the prepaid metering option. BC Hydro is therefore proposing to eliminate the Prepaid Metering option.

5.4.2 Security Deposits

BC Hydro states that under its current tariff, a security deposit collected from a residential or general service customer is based on two times the customer's estimated maximum monthly bill and that it proposes that the security deposit be based on two times the customer's estimated average monthly bill, rather than the maximum monthly bill.

5.4.3 Minimum Reconnection Charges

BC Hydro states that the minimum reconnection charges as set out in the Schedule of Standard Charges are based on its costs for typical reconnections and that it proposes to update the minimum reconnection charges based on its current costs for typical reconnections, as follows:

Table 5-7

Table 9 – Proposed Minimum Reconnection Charges

	Existing Fee	Proposed Fee
Regular Hours	$64.00	$125.00
Overtime	$91.00	$158.00
Call Out	$217.00	$355.00

Source: Exhibit B-1, p. 60, Table 9

BC Hydro expects that the increase in fee revenue resulting from the proposed increases to the minimum reconnection charges will be approximately $1.0 million per annum.

5.4.4 Miscellaneous Charges

BC Hydro states that it is proposing increases to the Account Charge, the Collection Charge and the Call-Back Charge based on its current costs of providing the services. BC Hydro is also proposing to eliminate the refund administration fee.

The miscellaneous charges that BC Hydro is proposing are as follows:

Table 5-8

Table 10 Proposed Miscellaneous Charges

	Existing Fee	Proposed Fee
Late Payment Charge	1.5%	1.5%
Returned Cheque Charge	$20.00	$20.00
Account Charge	$10.00	$12.40
Transformer Rental Charge	17.0%	17.0%
Collection Charge	$32.00	$39.00
Data-Plus Service	$360.00	$360.00
Call-Back Charge	$140.00	$194.00
Refund Administration Fee	$75.00	N/A
Net Metering Site Acceptance	$600.00	$600.00

BC Hydro states that Data-Plus Service is a service that consolidates several accounts into one collective master account and that its administration requires a significant amount of manual processing which has prompted BC Hydro to propose to close the Data-Plus service with existing customers on Data-Plus Service being grandfathered until a replacement service becomes available.

BC Hydro states that under its current tariff, the late payment charge is not applicable to customers on the Equal Payment Plan; Pay as You Go Billing; or Pre-Authorized Payment Plan and that the exemption from late payment charges has become a particular concern with respect to Equal Payment Plan customers because approximately 16 percent of Equal Payment Plan bills are not paid by the due date. To treat all customers fairly, and to provide an appropriate incentive to all customers to pay their bills by the due date, BC Hydro is proposing that the late payment charge be applied to any account that is overdue, regardless of the billing option chosen.

BC Hydro estimates that the application of the late payment charge to overdue Equal Payment Plan bills would initially result in additional annual revenue of approximately $1.0 million. BC Hydro expects that this amount would decrease over time as those customers currently exempt from late payment charges modify payment behaviour to avoid such charges.

BC Hydro expects that the increase in fee revenue resulting from the proposed increases to the Miscellaneous Fees, including the expected increase resulting from the application of late payment charges to all customers, will be approximately $2.2 million per annum (Exhibit B-1, pp. 59-62).

BC Hydro submits that many of its proposed changes are administrative in nature and that some of the more substantive changes include removal of the distinction between extensions across private and public property (section 4.2.1); guarantees (section 4.2.3); extension fee refunds (section 4.2.4); pre-paid metering (section 4.3); security deposits (section 4.4); reconnection charges (section 4.6); and miscellaneous charges (section 4.7). These proposals have occasioned little or no comment from Intervenors, Commission staff, or the Commission Panel. Unchallenged as they are, BC Hydro submits that these proposals should be accepted by the Commission as filed by BC Hydro (BC Hydro Argument p. 62).

Commission Determination

Other than the Distribution Extension Policy, which is not approved, and the Service Connection Charge Schedule, which is approved with the Commission Panel's views set out above, the Commission Panel accepts BC Hydro's proposed changes to the Terms and Conditions of its Electric Tariff as filed.

6.0 OTHER MATTERS

In this Section the Commission Panel reviews matters which arose during the course of the proceeding, and gives BC Hydro directions concerning them.

6.1 Rate Schedule 1105

The Commission Panel has considered Special Condition 4 which deals with the ability of E-Plus customers to transfer to Rate Schedule 1101. The Commission Panel is of the view that the notice period and the inability to transfer during a period of interruption may not be in the public interest and directs BC Hydro to eliminate Special Condition 4. **The Commission Panel requests BC Hydro to consider the matter and to report to the Commission within 90 days as to why Special Condition 4 should not be eliminated.**

6.2 Miscellaneous Rate Schedules

The Commission Panel notes that Rate Schedules 1205, 1206 and 1207 all have declining block rate structures and requests BC Hydro to file a report with the Commission within 90 days on whether it is appropriate to eliminate these rates and if so how it proposes to do so.

The Commission Panel notes that the Application is silent on Rate Schedules 1277 and 1279, which are described as “Closed”. **BC Hydro is requested to file a report with the Commission within 90 days of this Order on whether it is appropriate to eliminate these rates and if so how it proposes to do so.**

6.3 Farms

The Commission Panel notes that farms appear to be able to receive service under a variety of Rate Schedules, including 1101,1105,1220,1201 and 1701. The Commission Panel believes BC Hydro should have a rate strategy for its agricultural customers, and urges it to engage in consultation with its agricultural stakeholders to establish a suitable rate strategy prior to its next rate design application. The Commission Panel is concerned that farmers take service under appropriate Rate Schedules for their domestic service as well as their commercial service.

6.4 Irrigation

The Commission Panel considers that establishing a rate class based on the capacity of a customer's pump may not necessarily be in the public interest. The Commission Panel urges BC Hydro to consider the suitability of Rate Schedules 1401 and 1402 for municipal and hotel/golf course customers and to address this issue in its next rate design application.

6.5 Metering Costs

BC Hydro was asked to provide the detailed calculations behind the metering allocation factors including both meter costs and installation costs. BC Hydro provided a table which showed the number of meters, replacement costs and average cost for each customer class, but no information on installation costs was provided (Exhibit B-1, BCUC 1.50.1).

The customer count, and forecast number of accounts are shown as being identical values (Exhibit B-1, Appendix A, Schedule 5.2), but these values are different than the number of meters.

BCOAPO submits that the customer count used in allocating customer-related distribution costs should reflect the number of multi-residential service drops as opposed to the number of account or meters (BCOAPO Argument, p. 37).

In Reply, BC Hydro submits that this is an entirely new issue not addressed during the proceeding and that no evidence as to materiality was presented and, therefore, it would be premature for the Commission to require BC Hydro to undertake a specific study on the topic (BC Hydro Reply, p. 19).

Commission Determination

The Commission Panel requests that BC Hydro, at its next FACOS or rate design filing, address the issue raised by BCOAPO and to provide a calculation of the metering allocation factors, including the installation cost, and a reconciliation of customer counts and number of meters.

6.6 Street Lighting

BC Hydro testified that it combines customer-owned and company-owned street lighting into one class because the only difference between the two is in ownership. BC Hydro further testified that the load characteristics of the two groups are the same but that the costs are different because there is no BC Hydro investment in customer-owned lights. BC Hydro also testified that the difference in costs is taken into account in rate design (T7:1157-1158).

BC Hydro's 1996/97 Proforma (sic) Fully Allocated Cost of Service at Schedule 1 showed customer and company-owned street lighting as separate classes and the R/C ratios were 0.695 and 1.210 respectively (Exhibit C7-21 Revised).

The issue was not addressed by any Intervenor or BC Hydro in Argument.

Commission Determination

Given the difference in connection requirements (cost of fixtures) between the two groups, the significant difference in R/C ratios, and the lack of evidence as to how the cost differences were taken into account in rates design, the Commission Panel requests BC Hydro to separate street lighting into two or more classes and to calculate R/C ratios for each class in its next FACOS or rate design filing.

6.7 Postage Stamp Rates

The concept of postage stamp rates refers to the practice of charging every customer within each class of service the same rate, regardless of the geographical region in the province in which service is provided, even though this may entail some cross-subsidies between customers in a class. BC Hydro's current rates are postage stamp within each of Tariff Zones I and II.

In addition to BC Hydro, Fortis BC and a few municipal and small private utilities also distribute electricity. Accordingly, the whole Province of British Columbia is not covered by postage stamp rates for either electricity or natural gas. Within the BC Hydro system, due to the Zone I and Zone II tariff structure distinction, there is a further introduction of two sets of postage stamp rates for the integrated and non-integrated service areas.

Although postage stamp rates are a high level policy issue, BC Hydro's Application does not explicitly address this policy matter. During the proceeding, BC Hydro testified:

> "BC Hydro considers one of the foundational elements of its rate design, its current rates, and the rate changes that it's proposed, to be the concept of postage stamps" (T6:924; T11:1770).

The only evidence of this policy introduced during the proceeding, was a 2003 letter from the Minister of Energy, Mines and Petroleum Resources to the President of the Union of British Columbia Municipalities indicating his support for postage stamp rates:

> "Electricity rates will be set on a postage stamp basis. This means all customers within a particular customer class will receive the same rate, regardless of their location in the Province" (Exhibit B-47).

In its response to Commission Panel IR, BC Hydro noted that in "the absence of any indication to the contrary … BC Hydro considers that postage stamp rates throughout Zone I and Zone II respectively are consistent with current government policy" (Exhibit B-10, Panel IR 1.12.0). BC Hydro also submits that there is very little evidence on the record from which one could make any meaningful conclusions about the possible benefits of regionally-differentiated rates, and does not believe any of its customer-Intervenors would support such rates (BC Hydro Argument, p. 63).

No Intervenors challenged BC Hydro’s position or addresses it in Argument.

Commission Determination

The Commission Panel is of the view that there is insufficient evidence before it which justifies any departure by BC Hydro from setting rates on the postage stamp principle.

7.0 SUMMARY OF DETERMINATIONS AND DIRECTIVES

This Summary is provided for the convenience of readers. In the event of any difference between the Determinations and Directions in this Summary and those in the body of the Decision, the wording in the Decision shall prevail.

	Directive	**Page**
1.	BC Hydro's proposed range of reasonableness of 90 percent to 110 percent is denied.	71
2.	BC Hydro is directed to adjust its rates in equal percentage amounts over the next three years so as to achieve R/C ratios of unity for each class after adjustments to the FACOS as described elsewhere in this Section and to file Rate Schedules for all classes for the first phase of the three year phase-in with rates effective April 1, 2008 with the Commission, together with supporting documentation, within 60 days of the date of Order No. G-111-07. BC Hydro is directed to undertake FACOS studies on an annual basis within 90 days of its fiscal year end in order to calculate actual R/C ratios and determine the need for future rate rebalancing applications in regard to the 95 percent to 105 percent range of reasonableness and submit the findings to the Commission.	71
3.	BC Hydro is directed to recalculate its FACOS based on a 4 CP allocation of transmission and demand-related generation costs in accordance with Order No. G-111-07.	82
4.	Considering past practice, and the results of the entire EES study, the Commission Panel determines that an allocation of the total distribution revenue requirement, from primary to meters and including related customer care costs and directly assigned street lighting on a 65 percent demand, 35 percent customer basis is appropriate and directs BC Hydro to revise its FACOS accordingly, as directed in Commission Order No. G-111-07. Further, BC Hydro is directed to conduct both a minimum system and zero intercept analysis for inclusion in its next FACOS or rate design filing.	88
5.	For purposes of this Application the Commission Panel finds a 55 percent demand 45 percent energy split using the demand (head) approach is reasonable absent a detailed study and BC Hydro is directed to recalculate the FACOS accordingly, as directed in Commission Order No. G-111-07. Further, BC Hydro is directed to include a detailed analysis of this issue as part of its next FACOS or rate design filing.	91

6.	On the balance of the evidence before it and without regard to the CEC submission in Argument, the Commission Panel finds that the functionalization of all revenue requirement related to demand-side management 90 percent to generation and 10 percent to transmission is appropriate. It also finds it appropriate that the portion functionalized to generation is allocated to the customer classes in the same proportions that the total generation revenue requirement is allocated to the customer classes, and directs BC Hydro to recalculate its FACOS accordingly, as directed in Commission Order No. G-111-07.	93
7.	The Commission Panel finds that Powerex Net Income results from both capacity and energy availability on BC Hydro's system, but finds that definitive evidence as to the split between capacity and energy was not presented and therefore determines that for the purposes of this FACOS, Powerex Net Income shall be allocated to customers classes in the same proportions that the total generation revenue requirement is allocated and directs BC Hydro to revise its FACOS accordingly, as directed in Commission Order No. G-111-07.	96
8.	BC Hydro is directed to prepare a study, for inclusion in its next FACOS or rate design filing that examines and quantifies the capacity benefits associated with IPP contracts.	99
9.	On the balance of the evidence before it, without regard to the calculation in CEC Argument, the Commission Panel finds that P3M costs are incurred for the benefit of all customers and should be allocated to customer classes in the same proportions as total generation revenue requirement and directs BC Hydro to recalculate its FACOS accordingly, as directed in Commission Order No. G-111-07.	100
10.	Accordingly, in future FACOS studies BC Hydro is directed to treat the revenue requirement related to the Trade Income Deferral in the same manner as Powerex Net Income, and the BCTC Deferral Account is to be functionalized to transmission.	102
11.	The Commission Panel approves BC Hydro's proposed changes to its Residential Rate Schedules identified in Section 4.1.4.	109
12.	In order that this proposal can be properly understood and evaluated by all of the stakeholders, the Commission Panel determines that BC Hydro's rebalancing proposal and the resultant proposed increase of one percent to BC Hydro's Residential Rate Schedules is denied. Further to the determinations in Section 3 of this Decision, BC Hydro's proposed range of reasonableness of 90 percent to 110 percent is denied. BC Hydro is directed to file Rate Schedules for its residential class to be effective April 1, 2008, which will reflect the first phase of a three-year equal percentage phase-in to achieve the R/C ratios of 1.0 based on the revised FACOS. BC Hydro is directed to file the revised documents referred to above with the Commission within 60 days of the date of Order No. G-111-07.	110

13.	The Commission Panel has also considered the E-Plus Group's submission that the price would never exceed two thirds of the "regular rate" and finds that this statement was made to the E-Plus customers in a letter from BC Hydro and that such a communication cannot bind the Commission.	134
14.	BC Hydro's application to amend Rate Schedules 1105, 1205, 1206 and 1207 is denied with the exception of BC Hydro's application to amend Rate Schedules 1105, 1205, 1206 and 1207 to restrict transfer of service, which the Commission Panel finds is in the public interest and is approved. The Commission Panel directs BC Hydro to include the interruptible service to its E-Plus customers as a separate class in its future FACOS with its next rate design application or rate design filing, and to calculate the costs of providing service as though it had the ability to interrupt the class for the four winter months, and to propose rates that move whatever R/C ratio results from this exercise to 1.0. Finally, the Commission Panel directs BC Hydro to pay more attention to the exercise of its rights under the Rate Schedules and to invest the necessary time and resources to ensure that its E-Plus customers comply with the Special Conditions of the Rate Schedules, and to work with E-Plus customers who may wish to move back to the firm rate to ensure that information on Power Smart programs are made available to them.	136
15.	The Commission Panel approves BC Hydro's proposal to eliminate Rate Schedules 1222 and 1223.	138
16.	The Commission Panel approves BC Hydro's proposed changes in respect of the Basic Charge and the minimum charge on the Small General Service rate.	139
17.	BC Hydro's proposed decrease of 5.2 percent to its Small General Service Rate Schedules is denied. As noted in Section 3 of this Decision, BC Hydro's proposed range of reasonableness of 90 percent to 110 percent is denied. BC Hydro is directed to file Rate Schedules for its Small General Service class to be effective April 1, 2008, which will reflect the first phase of a three-year equal percentage phase-in to achieve the R/C ratios of 1.0 based on the revised FACOS. BC Hydro is directed to file the revised documents referred to above with the Commission within 60 days of the date of Order No. G-111-07.	140
18.	The Commission Panel finds that BC Hydro's proposed restructuring of its Large General Service class was ill-conceived and poorly executed. The proposal is denied.	162

19.	Accordingly, BC Hydro is directed to commence meaningful stakeholder engagement with its Large General Service customers to develop, and file with the Commission an application for a rate structure or structures that encourage conservation without unduly benefiting or harming any of its customers in that class. Such a rate structure or structures should be in place by April 1, 2009 with a two-year phase-in if necessary. As noted in Section 3 of this Decision, BC Hydro's proposed range of reasonableness of 90 percent to 110 percent is denied. BC Hydro is directed to file Rate Schedules for its Large General Service class to be effective April 1, 2008, which will reflect the first phase of a three-year equal percentage phase-in to achieve the R/C ratios of 1.0 based on the revised FACOS. BC Hydro is directed to file the revised documents referred to above with the Commission within 60 days of the date of Order No. G-111-07.	163
20.	BC Hydro's proposal to create Rate Schedule 1402 is approved.	165
21.	BC Hydro's proposed increase to its Irrigation customers is denied. As noted in Section 3 of this Decision, BC Hydro's proposed range of reasonableness of 90 percent to 110 percent is denied. BC Hydro is directed to file Rate Schedules for its Irrigation class to be effective April 1, 2008, which will reflect the first phase of a three-year equal percentage phase-in to achieve the R/C ratios of 1.0 based on the revised FACOS. BC Hydro is directed to file the revised documents referred to above with the Commission within 60 days of the date of Order No. G-111-07.	166
22.	BC Hydro's proposal to eliminate Rate Schedules 1761 and 1770 is approved. BC Hydro's proposed range of reasonableness of 90 percent to 110 percent is denied. BC Hydro is directed to file Rate Schedules for its street lighting class to be effective April 1, 2008, which will reflect the first phase of a three-year equal percentage phase-in to achieve the R/C ratios of 1.0 based on the revised FACOS. BC Hydro is directed to file the revised documents referred to above with the Commission within 60 days of the date of Order No. G-111-07.	167

23.	Accordingly, BC Hydro's proposed SET policy is not approved. The allocation methodology to be applied is to be the Commission Panel's finding of 65 percent demand/35 percent customer. The calculation is to cover the 20 years proposed by BC Hydro, and is to use BC Hydro's nominal weighted average cost of capital of 8 percent, as recommended by the Guidelines and BC Hydro's existing SET policy, rather than BC Hydro's proposed rate of 6 percent. BC Hydro is ordered to recalculate its allowance levels in Table 5-1 of this Decision using the methodology set out above, and file the recalculated allowance levels within 60 days of the Order issued concurrently with this Decision. BC Hydro's proposal to charge the customer the lower of the extension charge under its existing SET Policy and the above extension policy from April 1, 2008 until June 30, 2008 is approved.	187
24.	The Commission Panel determines that BC Hydro's proposed Schedule of Service Connection charges is appropriate, and is so approved.	197
25.	Other than the Distribution Extension Policy, which is not approved, and the Service Connection Charge Schedule, which is approved with the Commission Panel's views set out above, the Commission Panel accepts BC Hydro's proposed changes to the Terms and Conditions of its Electric Tariff as filed.	200
26.	The Commission Panel requests BC Hydro to consider the matter and to report to the Commission within 90 days as to why Special Condition 4 should not be eliminated.	201
27.	The Commission Panel notes that Rate Schedules 1205, 1206 and 1207 all have declining block rate structures and requests BC Hydro to file a report with the Commission within 90 days on whether it is appropriate to eliminate these rates and if so how it proposes to do so.	201
28.	The Commission Panel notes that the Application is silent on Rate Schedules 1277 and 1279, which are described as "Closed". BC Hydro is requested to file a report with the Commission within 90 days of this Order on whether it is appropriate to eliminate these rates and if so how it proposes to do so.	201

DATED at the City of Vancouver, in the Province of British Columbia, this 26th day of October 2007.

Original signed by:

A.J. (TONY) PULLMAN
PANEL CHAIR & COMMISSIONER

Original signed by:

LIISA A. O'HARA
COMMISSIONER

Original signed by:

ROBERT J. MILBOURNE
COMMISSIONER

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-130-07

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by British Columbia Hydro and Power Authority
2007 Rate Design ("2007 RDA") Phase I

BEFORE: A.J. Pullman, Panel Chair
R.J. Milbourne, Commissioner
L.A. O'Hara, Commissioner

October 26, 2007

O R D E R

WHEREAS:

A. British Columbia Hydro and Power Authority ("BC Hydro") filed on March 15, 2007, pursuant to the Utilities Commission Act ("the Act") and Commission Order No. G-148-06, the 2007 Rate Design Application ("Application") to update BC Hydro's rates and terms and conditions of service; and

B. The Application addresses rate rebalancing, rate restructuring, changes to the E-Plus rates, General Service rates, and amendments to its Terms and Conditions of Service, including the distribution extension policy. On May 8, 2007, the Commission established an oral public hearing process for the review of the Application by Order No. G-50-07 (Exhibit A-4); and

C. Central Coast Power Corporation ("CCPC") is an Independent Power Producer ("IPP") in the Non-Integrated Area ("NIA") whose Energy Purchase Contract with BC Hydro was the subject of Information Requests and a motion by a Registered Intervenor, the Heiltsuk Tribal Council/Shearwater Marine Ltd. ("Heiltsuk"). On July 3, 2007, the Commission issued Commission Letter No. L-57-07 to inform all Parties that the Commission would hear the motion from Heiltsuk immediately following the Opening Statement of the Panel Chair; and

D. The Commission Panel Hearing Issues List was issued on July 6, 2007 (Exhibit A-23). Items No. 6 and 7 on the Issues List related to "NIA – Zone II rates" and the "Bella Bella NIA" and were identified in the cover letter as subject to the Commission Panel's determination on the motions then before the Panel; and

E. By letter dated July 6, 2007, BC Hydro submitted its compliance filings on interruptible rates to IPPs serving Zone II customers for the period commencing July 1, 2007 and ending June 30, 2008 (Exhibit A2-3); and

F. The public hearing commenced on July 9, 2007 in Vancouver; and

G. By letter dated July 11, 2007, BC Hydro filed with the Commission a proposal that the F2006 Zone II Special Contract rate of $0.1769 per kWh effective June 1, 2006 continue for the contract year beginning June 1, 2007 on an interim (refundable) basis (Exhibit B-37); and

H. By letters dated July 16, 2007, Heiltsuk filed two complaints with the Commission. One complaint was made pursuant to Commission Order No. G-30-02 and another complaint was made pursuant to Section 25 of the Act (respectively Exhibit C23-14 and Exhibit C23-15); and

I. On July 17, 2007, the Commission Panel made the determination that the Application would be heard in three phases. Phase I would cover the issues in Items No. 1 to 5 of the Issues List; Phase II would cover issues in Items No. 6 and 7 of the Issues List; and Phase III would cover the BC Hydro Special Contract rates (T8: 1331-1333 and T10: 1646-1648). The Commission Panel's determinations were set out in Commission Order No. G-84-07 dated July 27, 2007 (Exhibit A-25) and Commission Order No. G-97-07 dated August 20, 2007 (Exhibit A-30); and

J. Subject to the filing of certain outstanding information requests, the evidentiary phase of Phase I of the proceeding closed on July 19, 2007. The Panel Chair established a schedule for final argument which provided that BC Hydro file its Final Argument on August 3, 2007, Intervenors file their Arguments on August 17, 2007, and BC Hydro file its Reply Argument on August 24, 2007; and

K. On September 19, 2007 the Commission issued interim Order No. G-111-07 regarding FACOS and Rate Schedules to ensure that the Rate Schedules resulting from its Decision can be in place by April 1, 2008; and

L. The Commission Panel has reviewed the evidence and arguments submitted for this proceeding, and issues its Decision with respect to the Phase I issues.

NOW THEREFORE the Commission for the Reasons stated in the Decision issued concurrently with this Order, orders that:

1. The Commission interim orders that are the subject matter of Order No. G-111-07 are confirmed as final.

2. BC Hydro comply with all the directives of the Commission in the Decision, including those directives that are the subject matter of Order No. G-111-07.

3. BC Hydro's proposed changes to its Residential Rate Schedules identified in Section 4.1.4 of the Decision are approved.

4. BC Hydro's rebalancing proposal and the resultant proposed increase of one percent and a decrease of 5.2 percent to BC Hydro's Residential and Small General Service Rate Schedules, respectively are denied.

5. BC Hydro's application to amend Rate Schedules 1105, 1205, 1206 and 1207 to restrict transfer of service is approved. The application to otherwise amend Rate Schedules 1105, 1205, 1206 and 1207 is denied.

…/3

6. BC Hydro's proposal to eliminate Rate Schedules 1222 and 1223 is approved.

7. BC Hydro's proposed changes in respect of the Basic Charge and minimum charge on the Small General Service rate is approved.

8. BC Hydro's proposal to create Rate Schedule 1402 is approved.

9. BC Hydro's proposal to increase the rates to its Irrigation customers is denied.

10. BC Hydro's proposal to eliminate Rate Schedules 1761 and 1770 is approved.

11. BC Hydro's proposed SET policy is not approved. The allocation methodology to be applied to the SET policy is 65 percent demand/35 percent customer based on 20 years using BC Hydro's nominal weighted average cost of capital of 8 percent. BC Hydro is to recalculate its allowance levels in Table 5-1 of the Decision and file the recalculated allowance levels within 60 days of this Order issued concurrently with the Decision.

12. BC Hydro's proposal to charge the customer the lower of the extension charge under its existing SET Policy and the above extension policy from April 1, 2008 until June 30, 2008, is approved.

13. BC Hydro's proposed Service Connection Charge Schedule is approved.

14. Subject to paragraphs 11, 12 and 13 of this Order, BC Hydro's proposed changes to the Terms and Conditions of its Electric Tariff identified in Section 5 of the Decision are approved.

DATED at the City of Vancouver, in the Province of British Columbia, this 26th day of October 2007.

BY ORDER

Original signed by:

A.J. Pullman
Panel Chair

ACRONYMS AND ABBREVIATIONS

Amp	Ampere
Allowance	BC Hydro investment in a new distribution extension
AMI	Advanced Metering Infrastructure
Application	The 2007 Rate Design Application
BC Hydro, BCH	British Columbia Hydro and Power Authority
BCUC, Commission	British Columbia Utilities Commission
BCOAPO	British Columbia Old Age Pensioners Organization
BCSEA	BC Sustainable Energy Association
BCTC	British Columbia Transmission Corporation
BCTCDA	BCTC Deferral Account
CBL	Customer Base Load
CCPC	Central Coast Power Corporation
CE	Canadian Entitlement
CEC	Commercial Energy Consumers of BC
CIAC	Contributions In Aid of Construction
COS	Cost of Service
COFI	Council of Forest Industries
Corix	Corix Multi-Utility Services Inc.
CP	Coincidental Peak
CPCN	Certificate of Public Convenience and Necessity
CPR	Conservation Potential Review
CRI	Conservation Research Initiative
DCF	Discounted Cash Flow
DSM	Demand Side Management
EES	Economic and Engineering Services Inc.
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability

EP	E-Plus
EPA	Energy Purchase Agreement
EPG	E-Plus Homeowners Group
EPMC	Equal Percentable Marginal Cost
ESC	Energy Supply Contract
ESVI	Energy Solutions for Vancouver Island Society
FACOS	Fully Allocated Cost of Service Study
FERC	Federal Energy Regulatory Commission
FortisBC	FortisBC Inc.
GHG	Green House Gas
GRTA	Generation Related Transmission Assets
GS	General Service
GWh, GW.h	Gigawatt hour
HC	Heritage Contract
HC2	Heritage Special Direction
HDA	Heritage Payment Obligation Deferral Account
Heiltsuk	Heiltsuk Tribal Council and Shearwater Marine Ltd.
ICP	Island Co-generation Project
IEP	Integrated Electricity Plan
ILM	Interior Lower Mainland
IPP	Independent Power Producers
IR	Information Request
Issues List	Commission Panel Hearing Issues List
IRP	Integrated Resource Plan
JIESC	Joint Industry Electricity Steering Committee

kV	kiloVolts
KVA, kVa	kilovolt ampere
kW	kilowatt
kWh, kW.h	kilowatt/hour
LLH	Light Load Hour
LOLP	Loss of Load Probability
LRIC	Long Run Incremental Cost
LTAP	Long Term Acquisition Plan
MW	Megawatt
MWh, MW.h	Megawatt hour
NARUC	National Association of Regulatory Utilities Commissioners
NHDA	Non-Heritage Deferral Account
NIA	Non-Integrated Areas
NITS	Network Integration Transmission Services
NPV	Net Present Value
NSA	Negotiated Settlement Agreement
NSP	Negotiated Settlement Process
OATT	Open Access Transmission Tariff
OEB	Ontario Energy Board
OIC	Order in Council
O&M	Operating and Maintenance Costs
PLCC	Peak Load Carrying Capability
PV	Present Value
P3M	Power Planning and Portfolio Management

R/C	Revenue-to-Cost
RCE	Remote Community Electrification Program
RDA	Rate Design Application
REAP	Resource Expenditure and Acquisition Plan
RRA	Revenue Requirements Application
RS	Rate Schedule
SCCBC	Sierra Club of Canada, British Columbia Chapter *et al.*
SI	System Improvement
SET	System Extension Test
SET Guidelines	Commission System Extension Test Guidelines
SD	Special Direction
SMI	Smart Metering Infrastructure
Terasen	Terasen Utilities
TIDA	Trade Income Deferral Account
TPA	Transfer Pricing Agreement
TOU	Time-of-Use
UCA	Utilities Commission Act
VIGP	Vancouver Island Generating Plant project
VITR	Vancouver Island Transmission Reinforcement project
WTS	Wholesale Transmission Service

LIST OF APPEARANCES

G.A. FULTON, QC P. MILLER	Commission Counsel
J. CHRISTIAN M. STORONI L. MANNING	British Columbia Hydro and Power Authority
C. JOHNSON, QC M. GHIKAS	collectively Terasen Utilities - Terasen Gas Inc, Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc.
R. McDONELL	FortisBC
R. B. WALLACE I. CHANG	Joint Industry Electricity Steering Committee
D. NEWLANDS	Elk Valley Coal Corporation
R. McLAUGHLIN	Ministry of Energy, Mines and Petroleum Resources
R. CARLE	City of New Westminster
F. WEISBERG	Heiltsuk Tribal Council and Shearwater Marine Limited
C. WEAFER	Commercial Energy Consumers of British Columbia *et al.*
J. QUAIL L. WORTH	collectively BCOAPO *et al.* - British Columbia Old Age Pensioners'Organization, Active Support Against Poverty, BC Coalition of People with Disabilities, End Legislated Poverty, federated anti-poverty groups of BC and Tenant Resource and Advisory Centre Society
K. CAIRNS	E-Plus Homeowners Group
K. KNOTT A. KNOTT	Central Coast Power Corporation
W. ANDREWS	collectively BCSEA *et al.* B.C. Sustainable Energy Association, Sierra Club of Canada, British Columbia Chapter and Peace Valley Environmental Association

LIST OF APPEARANCES

L. BERTSCH	Energy Solutions for Vancouver Island Society
R. CLIFF	Corix Multi-Utility Services Inc

E. CHENG J.W. FRASER T. ROBERTS	Commission Staff
G. ISHERWOOD	Commission Consultant
ALLWEST REPORTING LTD.	Court Reporters & Hearing Officer

LIST OF WITNESSES

British Columbia Hydro and Power Authority Panel	Joanna Sofield Bridgette Zacharias Harold Nelson Arnie Reimer
British Columbia Old Age Pensioners Organization *et al.* Panel	Marvin Shaffer, Ph.D Colin Fussell
Terasen Gas Inc. Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc. Panel	Douglas Stout Tom Loski Ann Falcon Gail Tabone
The Joint Industry Electricity Steering Committee Panel	Joe N. Linxwiler, Jr. Lloyd Guenther John Allan Michael Jordan Bill LeGrow Mike Towers
E Plus Homeowners Group Panel	Gary McCaig Geoff Giles

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

British Columbia Hydro and Power Authority
2007 Rate Design Application

EXHIBIT LIST – Phase I

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated March 23, 2007 issuing Order No. G-36-07 setting Preliminary Regulatory Timetable and Notice of Procedural Conference
A-2	Letter dated April 5, 2007 issuing Commission Information Request No. 1
A-3	Letter dated May 2, 2007 issuing notice of available audio on-line broadcasting service on May 4, 2007 commencing at 1:30 p.m. for the balance of the proceeding
A-4	Letter dated May 8, 2007 and Order No. G-50-07 establishing an Oral Public Hearing and issuing the Regulatory Agenda and Reasons for Decision with respect to the Commission Panel's determinations on the hearing format, regulatory timetable and the disposition of the deferral account balances
A-5	Letter dated May 16, 2007 issuing Commission Information Request No. 2 to BC Hydro
A-6	Letter dated May 24, 2007 issuing amendment to date in Regulatory Timetable
A-7	Letter dated May 30, 2007 issuing a response to inquiry on BC Hydro contract between BC Hydro and Central Coast Power Corporation
A-8	Letter dated May 30, 2007 issuing Commission Panel Information Request No. 1 to BC Hydro
A-9	Letter dated June 13, 2007 issuing Commission Panel Information Request No. 2 to BC Hydro
A-10	Letter dated June 15, 2007 issuing Commission Information Request No. 1 to the Scott Thomson, Terasen Gas
A-11	Letter dated June 15, 2007 issuing Commission Information Request No. 1 to Jim Quail, BCOAPO

Exhibit No.	Description
A-12	Letter dated June 15, 2007 issuing Commission Information Request No. 1 to Kelly Cairns, representing the E-Plus Group
A-13	Letter dated June 15, 2007 issuing Commission Information Request No. 1 to Dan Potts of the JIESC
A-14	Letter dated June 15, 2007 issuing Commission Information Request No. 2 to Dan Potts of the JIESC
A-15	Letter dated June 15, 2007 issuing Commission Information Request No. 3 to Dan Potts of the JIESC
A-16	Letter dated June 15, 2007 issuing Commission Information Request No. 1 to Heiltsuk Tribal Council
A-17	Letter dated June 21, 2007 announcing the date, time and place of the public hearing; advising that Opening Statements will take place; and that BCOPAO's Witness Panel will also testify at the opening of the hearing
A-18	Letter dated June 25, 2007 addressing the issue of consultation with witnesses under cross-examination
A-19	Letter dated June 29, 2007 providing the participants with information to assist them by explaining the process of what to expect at the Oral Public Hearing
A-20	Letter dated July 4, 2007 responding to the Heiltsuk Motion
A-21	Letter dated July 5, 2007 issuing an amendment to the Oral Public Hearing hours
A-22	Letter dated July 6, 2007, issuing hearing notice to Central Coast Power Corporation to have their position presented on the Heiltsuk's Motion (Exhibit A-7 / Exhibit A-20)
A-23	Letter dated July 6, 2007, issuing the Commission Panel Hearing Issues List

Exhibit No.	Description
COMMISSION COUNSEL DOCUMENTS	
A2-1	Letter dated June 27, 2007 providing Participants with Procedural Information on the Oral Hearing Process
A2-2	**SUBMITTED AT HEARING** – Witness Aid on BC Hydro Electric Load Forecasts
A2-3	**SUBMITTED AT HEARING** – Copy of letter from BC Hydro filing a table showing the average unit cost per kilowatt hour incurred by BC Hydro to generate electricity at the diesel generating stations in Rate Zone II for F2007
APPLICANT DOCUMENTS	
B-1	Letter dated March 15, 2007 filing BC Hydro's 2007 Rate Design Application
B-2	Email dated April 4, 2007 filing confirmation of the Notice of Procedural Conference published in local and community newspapers (Order No. G-37-07)
B-3	Letter dated April 30, 2007 filing responses to the Commission and Intervenors Information Request No. 1
B-3-1	Letter dated May 8, 2007, filing outstanding responses to JIESC Information Requests No. 4.2 and 4.3
B-3-2	Letter dated May 16, 2007 filing Supplemental Response to JIESC Information Request 1.4.3 (Exhibit B-3-1)
B-3-3	Letter dated July 4, 2007 filing supplemental to ESVI Information Request No. 1.2.5 entitled "BC Hydro Electric Plus – Question and Answer Guide" dated September 1989
B-4	**SUBMITTED AT PROCEDURAL CONFERENCE** – BC Hydro Proposed Regulatory Timetable dated May 4, 2007
B-5	Letter dated May 9, 2007, filing response to request from E-Plus Homeowners Group to provide notification to all E-Plus customers during its next billing cycle on the group
B-6	Letter dated May 10, 2007 filing Notice of additional counsel, Mariana Storoni of Lawson Lundell

Exhibit No.	Description
B-7	Letter dated June 1, 2007 filing responses to the Commission and Intervenors Information Request No. 2 and notice to file outstanding IR's by June 8
B-7-1	Letter dated June 8, 2007, filing response to the Commission's Information Requests No. 2.111.1 and 2.111.2 and response to CECBC Information Request 2.8.2
B-8	Filing responses to the E-Plus Customers Information Request No. 1
B-9-1	Filing response to JIESC Information Request No. 3
B-9-2	Filing response to JIESC Information Request No. 4
B-9-3	Letter dated June 15, 2007 filing response to JIESC's Information Request No. 5
B-10	Letter dated June 15, 2007 filing response to Commission Panel's Information Request Round 1 (Exhibit A-8)
B-11	Letter dated June 15, 2007 filing response to Commission Panel's Information Request Round 1 (Exhibit A-9)
B-12	Letter dated June 15, 2007 filing Information Request No. 1 to the E-Plus Homeowners Group regarding its Evidence filed as Exhibit C8-6
B-13	Letter dated June 15, 2007 filing Information Request No. 1 to the Heiltsuk Tribal Council and Shearwater Marine Limited regarding its Evidence filed as Exhibit C23-4
B-14	Letter dated June 15, 2007 filing Information Request No. 1 to JIESC regarding its Evidence filed as Exhibit C18-9
B-15	Letter dated June 15, 2007 filing Information Request No. 1 to Terasen Gas Inc. regarding its Evidence filed as Exhibit C7-4
B-16	Letter dated June 20, 2007 from Jeff Christian, Lawson Lundell, legal counsel, filing response to Jim Quail, BCOAPO's witness panel request (Exhibit C6-8)
B-17	Letter dated June 29, 2007 filing the Direct Testimony of Joanna Sofield, Bridgette Zacharias, Harold Nelson, and Arnie Reimer
B-18	Letter dated June 29, 2007 filing revised responses to Terasen Gas' Information Request 1.18.4 and Peace River Regional District Information Request 2.1.1

Exhibit No.	Description
B-19	Letter dated July 3, 2007 filing response to counsel for Heiltsuk Tribal Council regarding the production of contractual arrangements between BC Hydro and Central Coast Power Corporation (CCPC) (Exhibit C23-7)
B-20	Letter dated July 4, 2007 filing response to Heiltsuk/Shearwater Information Request No. 3 (Exhibit C23-8)
B-21	Letter dated July 5, 2007 filing comments regarding the Commission Staff Issue List issued on July 3, 2007 (Exhibit A-19)
B-22	Letter dated July 6, 2007 responding to submission made by Heiltsuk/Shearwater (Exhibit C23-10)
B-23	Letter dated July 6, 2007 filing a Supplemental Response to Heiltsuk Information Request Question 2.30.1
B-24	Letter dated July 6, 2007 filing an Outline of Counsel's Opening Submissions and the Opening Joint Statement of Joanna Sofield and Bridgette Zacharias
B-25	**SUBMITTED AT HEARING** – Copy of letter dated May 8, 2007 to Tony Knotts, Central Coast Power Corp., advising of BC Hydro's Rate Design application before the Commission
B-26	**SUBMITTED AT HEARING** – BC Hydro's comments on Final Commission Panel Issues List
B-27	**SUBMITTED AT HEARING** – Undertaking at Volume 4, Page 603, Lines 3-7, responding to CECBC's question on revenue/cost ratios for the small commercial class in 1991 and 1998 FACOS
B-28	**SUBMITTED AT HEARING** – Undertaking at Volume 5, Page 827, Lines 9-17, responding to JIESC's question on DSM costs
B-29	**SUBMITTED AT HEARING** – Undertaking at Volume 5, Page 844, 845, 846, 847 and 848, responding to JIESC's question on statistical analysis on customer class
B-30	**SUBMITTED AT HEARING** – Undertaking at Volume 5, Page 745, Lines 8-26, responding to Terasen Utilities' question on revenue-to-cost ratios on a CP transmission rather than a CP allocator
B-31	**SUBMITTED AT HEARING** – Undertaking at Volume 5, Page 719, Lines 16 to page 720, line 3, responding to Terasen Gas' question on marketing natural gas instead of electricity to customers

Exhibit No.	Description
B-32	**SUBMITTED AT HEARING** – Undertaking at Volume 5, Page 818, Lines 4-12, responding to JIESC's question to support statement on FERC or OEB tests
B-33	**SUBMITTED AT HEARING** – Undertaking at Volume 5, Page 658, Line 21 to Page 65, Line 10, responding to the Chairperson's inquiry to summarize municipalities of E-Plus customers
B-34	**SUBMITTED AT HEARING** – Undertaking at Volume 5, Page 792, Lines 17 to Page 974, Line 4, responding to JIESC's question on rate design criteria
B-35	**SUBMITTED AT HEARING** – Undertaking at Volume 5, Page 690, Lines 2-10, Lines 13-17, Lines 20-22, responding to BCOAPO's questions on compressor stations and compressor loads
B-36	**SUBMITTED AT HEARING** – Undertaking at Volume 5, Page 689, Lines 10-13, and Lines 18-23, responding to BCOAPO's questions on residential billing
B-37	**SUBMITTED AT HEARING** – Copy of letter dated July 11, 2007 filing request for Interim Rates effective June 1, 2007
B-38	**SUBMITTED AT HEARING** – Undertaking at Volume 6, Page 944, Lines 2-3 and Lines 11-13, responding to Heiltsuk Tribal Council and Shearwater Marine Limited on questions regarding dams in Zone II
B-39	**SUBMITTED AT HEARING** – Undertaking at Volume 5, Page 795, Lines 8-11, responding to JIESC question on residential class growth
B-40	**SUBMITTED AT HEARING** – Undertaking at Volume 5, Page 693, Lines 22 to Page 695, Line 10, responding to BCOAPO's request for information on the Non-Heritage Deferral Account
B-41	**SUBMITTED AT HEARING** – Undertaking at Volume 6, Page 952, Lines 16 to Page 953, Line 15, responding to Heiltsuk's request for clarification on Zone II of rate classes and sub classes
B-42	**SUBMITTED AT HEARING** – Undertaking at Volume 5, Page 692, Line 7to Page 693, Line 10, filing response to BCOAPO's request for analysis on the impact on the average customer
B-43	**SUBMITTED AT HEARING** – Undertaking at Volume 5, Page 725, Line 23 to Page 726, Line 22, confirming TGI's inquiry on the information from the Federal Energy Management Program of the US Department of Energy's website

Exhibit No.	Description
B-44	**SUBMITTED AT HEARING** – Undertaking at Volume 5, Page 729, Lines 9-12, filing response to Terasen's inquiry on the efficiency of a combined cycle generation turbine
B-45	**SUBMITTED AT HEARING** – Undertaking at Volume 5, Page 755, Lines 12-16, filing confirmation on the capacity view of its load/resource balance on the integrated system peak load for resource planning
B-46	**SUBMITTED AT HEARING** – Undertaking at Volume 5, Page 1004, Lines 17-20, Page 1006, Lines 22-23 and Page 1007, Line 14 and Page 1008, Line 3, confirming the heating season in Q3 and Q4
B-47	**SUBMITTED AT HEARING** – Filing copy of letter from Ministry of Energy & Mines, Richard Neufield, Minister, to Patricia A. Wallace, President of Union of British Columbia Municipalities on the Government's new Energy Plan
B-48	**SUBMITTED AT HEARING** – Off-the-record request from Commission Counsel to provide first year revenue requirement impact in tabular form graph
B-49	**SUBMITTED AT HEARING** – Undertaking at Transcript Volume 5, Page 669, Lines 25 to Page 671, Line 24, on the cumulative rate impact of the various changes and the change in overall consumption
B-50	**SUBMITTED AT HEARING** – Undertaking at Transcript Volume 6, Page 870, Line 26, filing response to JIESC on the allocated COS analysis
B-51	**SUBMITTED AT HEARING** – Undertaking at Transcript Volume Volume 7, Page 1144, Line 26 to Page 1145, Line 7 – response regarding the targeted and actual accuracy (of demand load profiles) for each class
B-52	**SUBMITTED AT HEARING** – Undertaking at Transcript Volume 7, Page 1153, Lines 7-13 – response regarding the Columbia River Treaty CICA payments
B-53	**SUBMITTED AT HEARING** – Undertaking at Transcript Volume 7, Page 1111, Lines 11 – 25 – response regarding gas supply to Vancouver Island and Sunshine Coast
B-54	**SUBMITTED AT HEARING** – Undertaking at Transcript Volume 6, Page 938, Lines 9 -16 – response to the Heiltsuk Tribal Council and Shearwater Marine Limited regarding other NIAs that are physically integrated or are perhaps part of the same service territory as another public utility
B-55	**SUBMITTED AT HEARING** – Undertaking at Transcript Volume 7, Page 1134, Lines 13 -17 – response filing a table showing the comparison using a long-term debt rate of 4.6%

Exhibit No.	Description
B-56	**SUBMITTED AT HEARING** – Undertaking at Transcript Volume 5, Page 755, Line 21 to Page 756, Line 13 – response to Terasen Gas Inc. regarding the average residential customer load
B-57	**SUBMITTED AT HEARING** – Undertaking at Transcript Volume 5, Page 669, Line 25 to Page 671, Line 24 – response to BCOAPO regarding the cumulative rate impact of changes and the change in overall consumption due to BC Hydro's proposed rate changes
B-58	**SUBMITTED AT HEARING** – Undertaking at Transcript Volume 7, Page 1194, Lines 1 - 24; Page 1208, Line 18 to Page 1209 Line 5 – response to Commissioner Milbourne regarding an “export rate”
B-59	**SUBMITTED AT HEARING** – Document entitled “Electric Utility Cost Allocation Manual” dated January 1992 issued by the National Association of Regulatory Utility Commissioners
B-60	**SUBMITTED AT HEARING** – Letter dated July 16, 2007 filing copy of the Fiscal 2007 Fourth Quarter Deferral Account Report as of March 31, 2007
B-61	**SUBMITTED AT HEARING –** Undertaking at Transcript Volume 8, Page 1276, Line 4 to Page 1277, Line 15, filing response to Commissioner’s inquiry on revenue to cost ratio resulting from running the 2008 FACOS model
B-62	**SUBMITTED AT HEARING** – Undertaking at Transcript Volume 7, Page 1120, Lines 15 to 18, response to Commission’s inquiry on qualifications of Ms. Trudy Kwong and Mr. Tony Chu
B-63	**SUBMITTED AT HEARING** – Undertaking at Transcript Volume 7, Page 1113, Lines 17 to 21, response to Commission’s inquiry on FACOS studies for 1995, 1996 and 1997
B-64	**SUBMITTED AT HEARING** – Undertaking at Transcript Volume 7, Page 1156, Line 11 to Page 1157, Line 2, filing response to Commission’s inquiry on ranking IPP projects
B-65	**SUBMITTED AT HEARING** – Undertaking at Transcript Volume 8, Page 1279, Lines 6 to 26, filing response to Commission’s inquiry on new residential allowance extensions
B-66	**SUBMITTED AT HEARING** – Undertaking at Transcript Volume 5, Page 756, Lines 15 to Page 757, Line 10, filing response to Terasen Utilities’ inquiry on forecasting number of new customers using electric space heating compared to electric water heating

Exhibit No.	Description
B-67	**SUBMITTED AT HEARING** – Undertaking at Transcript Volume 5, Page 755, Line 21 to Page 756, Line 13, filing response to Terasen Gas' inquiry on the average residential customer load for the year
B-68	**SUBMITTED AT HEARING** – Table of meetings and workshops between JIESC and BC Hydro
B-69	**SUBMITTED AT HEARING** –Undertaking at Transcript Volume 6, Page 998, Line 25 to Page 999, Line 1, filing BC Hydro's response to E-Plus Group confirming the number of gigawatts of interruptible energy
B-70	**SUBMITTED AT HEARING** –Undertaking at Transcript Volume 7, Page 1083, Lines 4 to 9, filing BC Hydro's response to E-Plus Group request for efficiency rating for air source heat pump technologies
B-71	**SUBMITTED AT HEARING** –Undertaking at Transcript Volume 8, Page 1280, Lines 2 to 16, filing BC Hydro's response to Commission Panel confirming the amortization period for deferral accounts
B-72	**SUBMITTED AT HEARING** –Filing Testimony from Exhibit C7-4, Page 26
B-73	**SUBMITTED AT HEARING** –Undertaking at Transcript Volume 7, Page 1172, Line 22 to Page 1173, Line 23, filing response to Commission's request to provide a strawman regulatory rate filing agenda for a five year period
B-74	**SUBMITTED AT HEARING** –Undertaking at Transcript Volume 8, Page 1255, Line 25 to Page 1258, Line 11, filing response to Commission's Information Request 2.118.2
B-75	**SUBMITTED AT HEARING** –Undertaking at Transcript Volume 8, Page 1258, Line 18 to Page 1259, Line 2, filing response to Commission's request for BC Hydro's capacity profile and aggregate demand profile
B-76	**SUBMITTED AT HEARING** –Filing copy of the 2006 Appliance Saturation and Use Rate
B-77	**SUBMITTED AT HEARING** –Filing copy of the Electric Plus program from BC Hydro's website as of February 12, 2007
B-78	**SUBMITTED AT HEARING** – Undertaking at Transcript Volume 8, Page 1267, Line 5 to 6, filing response to Commission's request for clarification on the information regarding the electric service that irrigation customers receive

Exhibit No.	Description

INTERVENOR DOCUMENTS

C1-1	**SMITH, RALPH –** Web registration received March 19, 2007, filing request for Intervenor Status
C1-2	Email dated March 29, 2007 filing withdrawal of Registered Intervenor status
C1-3	Email dated March 30, 2007, filing correspondence between Ralph Smith and BC Hydro regarding E-Plus Program

CHANGE OF REGISTERED INTERVENOR STATUS TO INTERESTED PARTY STATUS
PLEASE REFER TO D-15

C2-1	**KNOX, FAWN –** Web registration received March 19, 2007, filing request for Intervenor Status
C3-1	**HARVIE, JOHN & MCWADE, KATHLINE –** Web registration received March 21, 2007, filing request for Intervenor Status
C4-1	**ROCHON, CHRISTOPHER –** Web registration received March 26, 2007, filing request for Intervenor Status
C4-2	E-mail dated April 4, 2007 filing Information Request No. 1 regarding the E-Plus Program
C4-3	Letter dated April 18, 2007 filing letter of comment to Bob Elton, CEO, BC Hydro
C4-4	Email dated April 24, 2007 filing inquiry on proceeding protocol at the Procedural Conference
C4-5	Email dated May 3, 2007 filing notice of legal counsel from Kelly Cairns to represent members of the E-Plus Group

**** NOW REPRESENTED UNDER INTERVENOR C8**
PLEASE REFER TO EXHIBIT C8-3
(E-PLUS HOMEOWNERS GROUP) **

C5-1	**FORTISBC INC. –** Web registration received March 28, 2007 from Brian Parent, filing request for Intervenor Status
C5-2	Letter dated April 11, 2007 filing Information Request No. 1 to BC Hydro

Exhibit No.	Description
C6-1	**BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION ET AL (BCOAPO)** - Received letter dated March 29, 2007 from Jim Quail requesting Intervenor Status for Leigha Worth, Counsel, and Jim Harper, Econalysis Consulting
C6-2	Letter dated April 11, 2007 filing Information Request No. 1 to BC Hydro
C6-3	Letter dated April 11, 2007 filing notice to add Colin Fussell to distribution list
C6-4	Letter dated May 16, 2007 filing Information Request No. 2 to BC Hydro
C6-5	Letter dated June 11, 2007 filing Evidence with the CVs of Dr. Marvin Shaffer and Mr. Colin Fussell
C6-6	Letter dated June 15, 2007 filing Information Request No. 1 to JIESC
C6-7	Letter dated June 15, 2007 filing Information Request No. 1 to Terasen Gas Utilities
C6-8	Letter dated June 18, 2007 filing notice of availability of witness panel for cross-examination in the Oral Public Hearing
C6-9	Letter dated June 25, 2007 filing response to Commission's Information Request No. 1
C6-10	Letter dated June 28, 2007, filing responses to Information Request from JIESC (Exhibit 18-14)
C6-11	Letter dated July 6, 2007 filing response to comments regarding the Commission Panel's Hearing Issues List in BC Hydro's letter of July 5, 2007 (Exhibit B-21)
C6-12	**SUBMITTED AT HEARING** – Copy of Long-Run Incremental Cost Update 2005-2006 Report to BC Hydro from Energy and Environmental Economics Inc.
C6-13	**SUBMITTED AT HEARING** – Extract from the BC Hydro, Wholesale Transmission Services Hearing Decision dated April 23, 1998
C6-14	**SUBMITTED AT HEARING** - Letter dated November 15, 2005 from Commission Counsel filing response to submission from to Hul'qllmi'nllm Treaty Group
C6-15	**SUBMITTED AT HEARING** - Response to Undertaking at Transcript Volume 4, page 538, line 25 to page 539, line 9 regarding the load factor of BC Hydro's domestic load and its transmission system for fiscal year 2005

Exhibit No.	Description
C6-16	**SUBMITTED AT HEARING** - Extract from Customer Baseline Load (CBL Determination Draft Guidelines of May 18, 2005
C6-17	**SUBMITTED AT HEARING** - Extract from the Ministry of Energy and Mines Backgrounder on Heritage Contract, Stepped Rates and Transmission Access – BCUC Recommendations & Government Response
C7-1	**TERASEN GAS INC. (TGI), TERASEN GAS (VANCOUVER ISLAND) (TGVI), AND TERASEN GAS (WHISTLER) (TGI) COLLECTIVELY CALLED TERASEN UTILITIES -** Received letter dated April 2, 2007 from Tom Loski requesting Intervenor Status and filing Notice to attend Procedural Conference
C7-2	Letter dated April 11, 2007 filing Information Request No. 1 to BC Hydro
C7-3	Letter dated May 16, 2007 filing Information Request No. 2 to BC Hydro
C7-4	Letter dated June 11, 2007 filing expert evidence of EES Consulting, Inc.
C7-4a	**SUBMITTED AT HEARING** – Filing revised evidence of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc. (the “Terasen Utilities" or the "Companies")
C7-5	Letter dated June 26, 2007 filing responses to Commission Information Request No. 1
C7-6	Letter dated June 26, 2007 filing responses to British Columbia Hydro and Power Authority Information Request No. 1
C7-7	Letter dated June 26, 2007 filing responses to the BC Old Age Pensioners Organization *et al*. Information Request No. 1
C7-8	Letter dated June 29, 2007 filing the Direct Testimony of the Terasen Utilities
C7-9	Letter dated July 5, 2007 filing comments on the Commission Staff Issues List
C7-10	**SUBMITTED AT HEARING** – Documents referred to during cross examination of BC Hydro by Terasen Utilities
C7-11	**SUBMITTED AT HEARING** – Documents referred to during cross examination of BC Hydro by Terasen Utilities – Book 2

Exhibit No.	Description
C7-12	**SUBMITTED AT HEARING** – Documents referred to during cross examination of BC Hydro by Terasen Utilities – Presentation by Bob Elton at the Pacific Economic Summit, "Taking Action: Responding to Climate Change" on May 31, 2007
C7-13	**SUBMITTED AT HEARING** – copy of the Direct Testimony of Kenneth H. Tiedemann from the BC Hydro 2006 IEP/LTAP Application
C7-14	**SUBMITTED AT HEARING** – Extract from BC Hydro and BCTC Application for Deferral Accounts Decision, dated October 29, 2004
C7-15	**SUBMITTED AT HEARING** – BC Hydro Witness Aid, series of graphs on BC Hydro's Domestic System Monthly Peak Demand 2001 to 2007
C7-16	**SUBMITTED AT HEARING** – Opening Statement of Douglas L. Stout, Terasen Utilities Panel
C7-17	**SUBMITTED AT HEARING** – Filing revised Attachment 1 to Terasen's Evidence providing the avoided space Heating Load Calculations based on Exhibit B-66
C7-18	**SUBMITTED AT HEARING** – Undertaking at Transcript Volume 9, Page 1598, Lines 3 to 24, filing response to Commission on if costs referenced represents the embedded cost of generation
C7-19	**SUBMITTED AT HEARING** – Undertaking at Transcript Volume 9, Page 1522, Line 22, to Page 1523, Line 4, filing response to BCOAPO on Hydro One transmission system
C7-20	**SUBMITTED AT HEARING** – Undertaking at Transcript Volume 9, Page 1599, Line 12 to 20, filing response to Chairperson on the net value calculations on electric space heating and electric water heating
C7-21	**SUBMITTED AT HEARING** – **REVISED** - Undertaking at Transcript Volume 9, Page 1620, Line 14 to Page 1621, Line 26, filing response to the Commission on the two studies used to determine the 53%/47% split (revised to include full copies of studies referenced)
C7-22	Undertaking at Transcript Volume 9, Page 1520, Line 17 to Page 1521, Line 3, responding to BCOAPO's request for the source data for transmission facilities
C7-23	Undertaking at Transcript Volume 9, Page 1595, Lines 10-24, responding to the Commission Panel's request for information on annual space heating load by dwelling type

Exhibit No.	Description
C7-24	Undertaking at Transcript Volume 9, Page 1633, Lines 4 to 21, responding to the Commission Chairperson's request for the average price of propane since 1987 for Revelstoke and furnace oil for Vancouver Island since 1991
C8-1	**E-PLUS HOMEOWNERS GROUP -** Email dated April 2, 2007 from R. Gary McCaig, spokesperson, requesting Intervenor Status
C8-2	Letter dated April 2, 2007 filing comments on the E-Plus agreements
C8-3	Email dated May 3, 2007 filing notice of legal counsel from Kelly Cairns to represent members of the E-Plus Group
	**** PLEASE REFER TO EXHIBIT C4-5****
C8-4	Letter dated May 24, 2007 filing Information Request No. 1 to BC Hydro
C8-5	Letter dated May 25, 2007 filing Errata to Information Request No. 1
C8-6	Letter dated June 11, 2007 from Kelly Cairns, legal counsel, filing Evidence of the E-Plus group
C8-7	Letter dated June 27, 2007 filing responses to Commission Information Request No. 1
C8-8	Letter dated June 27, 2007 filing responses to British Columbia Hydro and Power Authority Information Request No. 1
C8-9	Letter dated July 6, 2007 from Kelly Cairns, legal counsel, filing the Direct Testimony of Gary McCaig and Geoff Giles
C8-10	Letter dated July 6, 2007 from Kelly Cairns, legal counsel, filing the Direct Testimony of Dr. Chris Rochon
C8-11	**SUBMITTED AT HEARING** –Filed spreadsheet of E-Plus calculation of compensation
C9-1	**CORIX MULTI-UTILITY SERVICES INC. –** Letter dated April 2, 2007 from Ronald Cliff, President, Highcliff Energy Services Ltd. requesting Intervenor Status
C9-2	Letter dated April 11, 2007 from Ronald Cliff, President, Highcliff Energy Services Ltd. filing Information Request No. 1 to BC Hydro
C9-3	Letter dated May 16, 2007 filing Information Request No. 2 to BC Hydro

Exhibit No.	Description
C10-1	**GILROY, GARTH -** Web registration received April 2, 2007 requesting Intervenor Status
C11-1	**WEST FRASER MILLS LTD. –** Online web registrations received April 3, 2007 from Bill Legrow and David Humber, requesting Intervenor Status
C12-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC) –** Letter dated April 4, 2007 from Christopher Weafer, legal counsel, of Owen Bird, and on behalf of David Craig of Consolidated Management Consultants Ltd., requesting Intervenor Status
C12-2	Letter dated April 11, 2007 from Christopher Weafer, legal counsel, of Owen Bird, filing Information Request No. 1 to BC Hydro
C12-3	Letter dated May 16, 2007 filing Information Request No. 2 to BC Hydro
C12-4	Letter dated July 5, 2007 filing comments on the Commission Staff Issues List
C12-5	Letter dated July 6, 2007 filing comments in support of JIESC comments (Exhibit C18-15)
C12-6	**SUBMITTED AT HEARING** – Filing the Opening Statement of Commercial Energy Consumers Association of BC (CECBC)
C12-7	**SUBMITTED AT HEARING** – filing copy of BC Hydro's Service Plan 2006 - 2008
C12-8	**SUBMITTED AT HEARING** – Filing copy of the 4th Session, 37th Parliament Report of Proceedings (Hansard) Select Standing Committee on Crown Corporations
C12-9	**SUBMITTED AT HEARING** – Filing copy of the BCHydro Presentation to the Select Standing Committee on Crown Corporations
C13-1	**PEACE RIVER REGIONAL DISTRICT (PRRD) –** Letter dated April 4, 2007 from Fred Banham, and on behalf of Dave Read, Aspen Communications Ltd., requesting Intervenor Status
C13-2	Letter dated April 9, 2007 filing Information Request No. 1 to BC Hydro
C13-3	Letter dated May 16, 2007 filing Information Request No. 2 to BC Hydro

Exhibit No.	Description
C14-1	**CITY OF NEW WESTMINSTER –** Letter dated April 5, 2007 from R.E. Carle, General Manager, requesting Intervenor Status
C15-1	**GREIG, JAMES –** Email dated April 5, 2007 requesting Intervenor Status
C16-1	**NICHOLLS, DAVID –** E-mail dated April 5, 2007 requesting Intervenor Status
C17-1	**WEATHERALL, BILL –** E-mail dated April 5, 2007 requesting Intervenor Status
C18-1	**JOINT INDUSTRY ELECTRICITY STEERING COMMITTEE (JIESC) –** Letter dated April 5, 2007 from R. Brian Wallace, Counsel, Bull, Housser & Tupper, requesting Intervenor Status
C18-2	Letter dated April 11, 2007 filing Information Request No. 1 to BC Hydro
C18-3	Letter dated May 16, 2007 filing Information Request No. 2 to BC Hydro
C18-4	Letter dated May 30, 2007 filing request to add Ian May of Ian May Consulting Ltd. to distribution lists for all correspondence and materials
C18-5	Letter dated May 31, 2007 filing Information Request No. 3 to British Columbia Hydro and Power Authority regarding Exhibit B-3-2
C18-6	Letter dated June 4, 2007 filing Information Request No. 4 to BC Hydro seeking further clarification and information to BC Hydro response (Exhibit B-7)
C18-7	Letter dated June 11, 2007 filing Evidence of Lloyd Guenther
C18-8	Letter dated June 11, 2007 filing Evidence of Joe N. Linxwiler Jr.
C18-9	Letter dated June 11, 2007 filing Policy and Impacts Evidence of the JIESC Steering Committee
C18-10	Letter dated June 11, 2007 filing Information Request No. 5 to BC Hydro
C18-11	Letter dated June 26, 2007 filing response to the Commission's Information Request No. 1, 2 and 3
C18-12	Letter dated June 26, 2007 filing response to BC Hydro's Information Request No. 1
C18-13	Letter dated June 26, 2007 filing Information Request No. 1 to BCOAPO

Exhibit No.	Description
C18-14	Letter dated June 26, 2007 filing response to BCOAPO's Information Request No. 1
C18-15	Letter dated July 6, 2007 filing response to comments regarding the Commission Panel's Hearing Issues List in BC Hydro's letter of July 5, 2007 (Exhibit B-21)
C18-16	**SUBMITTED AT HEARING** – Document submitted regarding BC Hydro Cost of Energy Market Purchases ($/MWh)
C18-16A	**SUBMITTED AT HEARING** – Additional document submitted regarding BC Hydro Cost of Energy Market Purchases ($/MWh)
C18-17	**SUBMITTED AT HEARING** – Submitted Order G-79-05 and Reasons for Decision, Appendix A and an attachment from the BC Public Interest Advocacy Centre
C18-18	**SUBMITTED AT HEARING** – Document submitted regarding Revenue to Cost Ratios Using BCOAPO EPMC Revenues and BC Hydro Costs
C18-18A	**SUBMITTED AT HEARING** – Document submitted regarding Linxwiler Analysis of BC Hydro's Monthly Peak Demands for Fiscal Yeas 2001 – 2007
C18-19	**SUBMITTED AT HEARING** - Appendix A-1 of Appendix D of the Deferral Account Report dated March 31, 2005
C18-20	**SUBMITTED AT HEARING** – Document submitted from BC Hydro Electric Tariff, third revision of page C55-1, effective February 1, 2007
C18-21	**SUBMITTED AT HEARING** – Excerpt from a powerpoint presentation dated March 21, 2007, entitled "Conservation Research Institute, Residential Time of Use Program Working Group Meeting No. 2"
C18-22	Undertaking at Volume 9, Page 1461, filing response to the Information Request from the Commission to provide a breakdown of RS1211 and RS1823 energy use for West Fraser and Tolko
C18-23	Undertaking at Volume 9, Page 1466, filing response to the Information Request from the Commission on service to Canfor, Wet Fraser and Tolko operations
C18-24	Undertaking at Volume 9, Page 1476-1477, filing response to the Information Request from the Commission on BC Hydro's Option 1

Exhibit No.	Description
C19-1	**BC SUSTAINABLE ASSOCIATION, SIERRA CLUB OF CANADA (BRITISH COLUMBIA CHAPTER), AND PEACE VALLEY ENVIRONMENTAL ASSOCIATION (COLLECTIVELY "BCSEA") –** Letter dated April 5, 2007 from William J. Andrews, Counsel, requesting Intervenor Status
C20-1	**CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES UNION, LOCAL 378 (COPE)** – Letter dated April 5, 2007 requesting Intervenor status
C20-2	Letter dated April 11, 2007, filing Information Request No. 1 to BC Hydro
C21-1	**ELK VALLEY COAL CORPORATION (EVCC)** – E-mail dated April 5, 2007 from J. David Newlands requesting Intervenor status
C22-1	**HAZELWOOD, DAVID** – E-mail dated April 5, 2007 requesting Intervenor status
C23-1	**HEILTSUK TRIBAL COUNCIL & SHEARWATER MARLINE LIMITED (HEILTSUK ET AL.)** – Letter dated April 5, 2007 from Fred J. Weisberg, Counsel requesting Intervenor status
C23-2	Letter dated April 11, 2007 filing Information Request No. 1 to BC Hydro
C23-3	Letter dated May 16, 2007 filing Information Request No. 2 to BC Hydro
C23-4	Letter dated June 12, 2007 filing Evidence of the Heiltsuk Tribal Council and Shearwater Marine Limited
C23-5	Letter dated June 26, 2007 filing responses to Commission Information Request No. 1
C23-6	Letter dated June 26, 2007 filing responses to British Columbia Hydro and Power Authority Information Request No. 1
C23-7	Letter dated June 28, 2007 filing a request for the production of documents (information request to the Commission)
C23-8	Letter dated July 3, 2007 filing Information Request No. 3 to BC Hydro
C23-9	Letter dated July 3, 2007 filing reply comments to BC Hydro's letter of July 3, 2007 (Exhibit B-19)
C23-10	Letter dated July 4, 2007 filing request for a Commission Order to direct BC Hydro to respond to outstanding questions in Information Request No. 3 filed July 3, 2007 (Exhibit C23-8/Exhibit B-20)

Exhibit No.	Description
C23-11	Letter dated July 5, 2007 filing comments on the Commission Staff Issues List
C23-12	Letter dated July 6, 2007 filing response to comments regarding the Commission Panel's Hearing Issues List in BC Hydro's letter of July 5, 2007 (Exhibit B-21)
C23-13	**SUBMITTED AT HEARING** – Letter dated July 8, 2007 filing Motion for Production of the BC Hydro / CCPC contracts
C23-14	**SUBMITTED AT HEARING** – Letter dated July 16, 2007 filing notice to register a formal complaint regarding Central Coast Power Corporation (CCPC) pursuant to Order No. G-30-02
C23-15	**SUBMITTED AT HEARING** – Letter dated July 16, 2007 filing complaint regarding Central Coast Power Corporation (CCPC) pursuant to Section 25 of the Utilities Commission Act
C24-1	**MINISTRY OF ENERGY, MINES & PETROLEUM RESOURCES (MEMPR)** – Letter dated April 5, 2007 requesting Intervenor status
C25-1	**ENERGY SOLUTIONS FOR VANCOUVER ISLAND SOCIETY (ESVI)** – Online web registration dated April 5, 2007 from Ludo Bertsch, of Horizon Technologies Inc. requesting Intervenor status
C25-2	Email dated April 11, 2007 from Ludo Bertsch, of Horizon Technologies Inc. requesting Intervenor status on behalf of Energy Solutions for Vancouver Island Society (ESVI)
C25-3	Letter dated April 11, 2007 from Ludo Bertsch, of Horizon Technologies Inc. filing Information Request No. 1 to BC Hydro
C25-4	Email dated May 1, 2007 filing notice of attendance at the Pre-Hearing Conference
C26-1	**COUNCIL OF FOREST INDUSTRIES (COFI)** – Letter dated April 16, 2007 from John Allan, requesting Intervenor status
C27-1	**HIGHBURY ASSET MANAGEMENT** - Online web registration dated April 5, 2007 from Leigh Large requesting late Intervenor status

Exhibit No.	Description
C28-1	**GILES, GEOFF & LINDA –** Email dated February 26, 2007 filing comments and inquiries on procedural hearing
C28-2	Email dated April 30 2007 filing comments on E-Plus
C29-1	**HAZELL, JOHN –** Online web registration dated May 3, 2007 requesting late Intervenor status
C29-2	E-mail dated May 3, 2007 filing comments on the Rate Design Application
C30-1	**CENTRAL COAST POWER CORPORATION (CCPC)** – Opening Statement
C30-2	**SUBMITTED AT HEARING** – Email dated May 17, 2007 from S. Pun Chu at BC Hydro, filing comments regarding the filing of the EPA and confidentiality clause
C30-3	**SUBMITTED AT HEARING** – Letter dated July 17, 2007 from Tony Knott, filing comments on the oral determination in respect to the timing of phase II

INTERESTED PARTY DOCUMENTS

D-1	Email received March 8, 2007 from Kerry Davis filing request for Interested Party
D-2	Email received March 20, 2007 from Stephen Baker, Senior Regulatory Analyst, Fellon-McCord & Associates filing request for Intervenor Status
D-3	Online web registration received March 20, 2007 from Warren Ward filing request for Interested Party
D-4	Online web registration received March 22, 2007 from Tim Kirkham filing request for Interested Party
D-4-1	Email dated March 22, 2007 filing comments on the Electric Plus Program
D-5	Online web registration received March 22, 2007 from Michael Sage filing request for Interested Party
D-6	Online web registration received March 22, 2007 from Dennis Raymond filing request for Interested Party
D-7	Online web registration received March 26, 2007 from Jeannie Boscariol filing request for Interested Party

Exhibit No.	Description
D-8	Online web registration received March 26, 2007 from John E. Elliott, of Elliott Energy Services Ltd., filing request for Interested Party
D-9	Online web registration received March 26, 2007 from Monty Smith filing request for Interested Party
D-10	Online web registration received March 12, 2007 from Tara Thurber filing request for Interested Party
D-11	Online web registration received March 30, 2007 from Stuart Holland filing request for Interested Party
D-12	Online web registration received April 2, 2007 from Derek Parsons filing request for Interested Party
D-13	Email dated April 2, 2007 from John Shaw, Victoria, BC filing comments and request for Interested Party
D-14	Fax dated April 2, 2007 from R.B. Pitfield, Victoria, BC filing comments and request for Interested Party
D-15	Email dated April 2, 2007 from Ralph Smith changing status from Registered Intervenor to Interested Party (Previously C1-1)
D-16	Email dated April 3, 2007 from Hector and Doreen Dubois, Campbell River, BC filing request for Interested Party
D-17	Online web registration received April 10, 2007 from Helen Eng filing request for Interested Party
D-17-1	Letter dated April 13, 2007 filing comments on E-Plus program
D-18	Online web registration received April 5, 2007 from Jim Powell filing request for Interested Party
D-19	Email received March 16, 2007 from Evonne & Aime Duquette, Victoria, BC filing request for Interested Party
D-20	Email received April 15, 2007 filing request for Interested Party regarding earlier submission on March 13, 2007 from Rob & Dale Smith of Sechelt, BC
D-21	Online web registration dated April 23, 2007 from Delija Geca, Hydro Quebec, requesting Interested Party Status
D-22	Online web registration dated April 25, 2007 from Artur Kruszewski, requesting Interested Party Status

Exhibit No.	Description
D-23	Online web registration dated May 2, 2007 from Hans Larsen requesting Interested Party status
D-24	Online web registration dated May 8, 2007 from Paul Schachter requesting Interested Party status
D-24-1	Letter dated March 5, 2007 to BC Hydro from Paul Schachter & Denise Reinhardt filing comments on E-Plus

LETTERS OF COMMENT

E-1	Letter of Comment emailed March 19, 2007 from Maurice Boulanger, Salmon Arm, BC
E-2	Letter of Comment dated April 13, 2007 from Jack & Vi Fell, Lantzville, BC
E-3	Letter of Comment dated April 16, 2007 from John Wild, Nanaimo, BC
E-4	Letter of Comment dated May 6, 2007 from Kathy and Cyril Goosney, Cranbrook, BC
E-4-1	Letter of Comment dated May 6, 2007 from Kathy and Cyril Goosney, Cranbrook, BC with additional documentation
E-5	Letters of Comment dated February 12, 2007 from various individuals
E-6	Letters of Comment dated February 13, 2007 from various individuals
E-7	Letters of Comment dated February 14, 2007 from various individuals
E-8	Letters of Comment dated February 15, 2007 from various individuals
E-9	Letters of Comment dated February 16, 2007 from various individuals
E-10	Letters of Comment dated February 17, 2007 from various individuals
E-11	Letters of Comment dated February 18, 2007 from various individuals
E-12	Letters of Comment dated February 19, 2007 from various individuals
E-13	Letters of Comment dated February 20, 2007 from various individuals
E-14	Letters of Comment dated February 21, 2007 from various individuals
E-15	Letters of Comment dated February 22, 2007 from various individuals

Exhibit No.	Description
E-16	Letters of Comment dated February 23, 2007 from various individuals
E-17	Letters of Comment dated February 24, 2007 from various individuals
E-18	Letters of Comment dated February 25, 2007 from various individuals
E-19	Letters of Comment dated February 26, 2007 from various individuals
E-20	Letters of Comment dated February 27, 2007 from various individuals
E-21	Letters of Comment dated February 28, 2007 from various individuals
E-22	Letters of Comment dated March 1, 2007 from various individuals
E-23	Letters of Comment dated March 2, 2007 from various individuals
E-24	Letters of Comment dated March 3, 2007 from various individuals
E-25	Letters of Comment dated March 4, 2007 from various individuals
E-26	Letters of Comment dated March 5, 2007 from various individuals
E-27	Letters of Comment dated March 6, 2007 from various individuals
E-28	Letters of Comment dated March 7, 2007 from various individuals
E-29	Letters of Comment dated March 8, 2007 from various individuals
E-30	Letters of Comment dated March 9, 2007 from various individuals
E-31	Letters of Comment dated March 10, 2007 from Lorine and Paul Bowers
E-32	Letters of Comment dated March 11, 2007 from Robb Smith, Salt Spring Island, BC
E-33	Letters of Comment dated March 12, 2007 from various individuals
E-34	Letters of Comment dated March 13, 2007 from various individuals
E-35	Letters of Comment dated March 14, 2007 from various individuals
E-36	Letter of Comment dated May 15, 2007 from Sherwin Harris
E-37	Letters of Comment dated March 15, 2007 from various individuals
E-38	Letters of Comment dated March 16, 2007 from various individuals

Exhibit No.	Description
E-39	Letters of Comment dated March 17, 2007 from various individuals
E-40	Letters of Comment dated March 18, 2007 from various individuals
E-41	Letters of Comment dated March 19, 2007 from various individuals
E-42	Letters of Comment dated March 20, 2007 from various individuals
E-43	Letters of Comment dated March 21, 2007 from various individuals
E-44	Letters of Comment dated March 24, 2007 from various individuals
E-45	Letters of Comment dated March 25, 2007 from Barron Carswell, Victoria BC
E-46	Letters of Comment dated March 26, 2007 from various individuals
E-47	Letters of Comment dated March 27, 2007 from Dwight Brown
E-48	Letters of Comment dated March 28, 2007 from various individuals
E-49	Letters of Comment dated March 29, 2007 from Norman Wale
E-49-1	Letter of Comment dated July 16, 2007 from Norman Wale
E-50	Letters of Comment dated March 30, 2007 from various individuals
E-51	Letter of Comment dated May 23, 2007 from M. Zacharias, Pender Island, BC
E-52	Letters of Comment dated April 2, 2007 from Ken Thomas, 100 Mile House, BC
E-53	Letters of Comment dated April 3, 2007 from various individuals
E-54	Letters of Comment dated April 4, 2007 from George Fisher, Lantzville, BC
E-55	Letters of Comment dated April 6, 2007 from Peter Dumlich, Chetwynd, BC
E-56	Letters of Comment dated April 10, 2007 from Jim & Linda Welch
E-57	Letters of Comment dated April 17, 2007 from various individuals
E-58	Letters of Comment dated April 24, 2007 from Nellie Numan, Burnaby, BC
E-59	Letters of Comment dated April 2, 2007 from various individuals
E-60	Letter of Comment dated May 28, 2007 from Janet Sankey and Hubert Bruns of Duncan, BC

Exhibit No.	Description
E-61	Letter of Comment dated June , 2007 from Jamie Bowman, of Comox, BC
E-62	Letter of Comment dated April 3, 2007 from Chris Cowland
E-63	**SUBMITTED AT HEARING** – Letter of Comment dated July 17, 2007 from Vincent Erenst, Managing Director, Marine Harvest Canada Inc.