IN THE MATTER OF

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

AND

AN INQUIRY INTO A HERITAGE CONTRACT FOR BRITISH COLUMBIA HYDRO AND POWER AUTHORITY'S EXISTING GENERATION RESOURCES AND REGARDING STEPPED RATES AND TRANSMISSION ACCESS

REPORT AND RECOMMENDATIONS

October 17, 2003

Before:

Robert H. Hobbs, Chair
Kenneth L. Hall, Commissioner
Paul G. Bradley, Commissioner

EXECUTIVE SUMMARY

The Government's Energy for Our Future: a Plan for BC ("Energy Plan") mandated that the BC Utilities Commission conduct an Inquiry to develop and refine certain policy areas relating to regulation of BC Hydro. The Inquiry concludes with this Report.

The Commission was requested to make recommendations on two key policy initiatives in the Energy Plan. First, benefits attributable to the existing low-cost generation of BC Hydro are to be secured for British Columbians by means of a Heritage Contract. Second, more efficient use of energy resources and private investment in new generation are to be fostered by a stepped rate structure for large commercial and industrial customers.

The Commission established a procedure designed to encourage public participation in the development of the requested recommendations. BC Hydro filed, as directed, a Proposal that became the subject of information sessions and workshops leading up to a public hearing. At the hearing the Commission Panel heard the views of consumer and industrial groups.

Three points enunciated at the Inquiry place the recommendations of the Commission Panel in context. First, BC Hydro's expressed concern in preparing its Proposal was maximization of the total amount of wealth to the province. The sharing of that wealth was deemed a secondary issue, and one that was largely left to the Government and the Commission. Second, BC Hydro's Proposal for a Heritage Contract had the support of almost all participants. Third, most participants believed that the recommendations should be focused on principles, with implementation details left to later Commission decisions.

The BC Hydro Proposal for the Heritage Contract between BC Hydro's Generation and Distribution arms was based on the revenue required by Generation to meet the embedded cost of supplying the energy of Heritage Resources to Distribution ("the Revenue Requirements model"). A salient feature of the Revenue Requirement model is that Generation remains subject to traditional regulatory oversight, with the opportunity for performance-based ratemaking ("PBR"). BC Hydro believes that the Revenue Requirements model ensures the appropriate alignment of interests of BC Hydro Distribution, BC Hydro Generation, and Powerex, and that such alignment is necessary for the efficient dispatch of the Heritage Resources and effective planning for new resources.

One intervenor, CBT Energy Inc., offered an alternative proposal similar to the contract adopted by Quebec. This form of Heritage Contract would specify a fixed quantity of heritage energy to be supplied at a fixed price over the duration of the contract ("The Fixed Price/Fixed Quantity model"). Its declared advantage is to afford greater certainty for consumers. This model would, however, impose greater risk on BC Hydro, requiring a risk premium to be borne by consumers. A further feature of such a contract would be to remove the need to regulate BC Hydro Generation.

Customer advocates believe that the Revenue Requirements model ensures continuing congruence of risks and rewards, that is, it ensures risks and rewards are borne by customers. The Fixed Price/Fixed Quantity contract requires the problematic determination of fair compensation for the risks, and it does not ensure that full heritage benefits will remain with customers. For these reasons, together with strong support for ongoing regulation of BC Hydro Generation, customers unanimously support the Revenue Requirements model.

This Report endorses the preference of the customers and BC Hydro, and makes recommendations for the implementation of a Revenue Requirements model for the Heritage Contract. The proposed Heritage Contract is attached as an appendix to the report; the accounts necessary for implementation of this model are set forth in a proposed special direction.

One feature of the BC Hydro Proposal that warranted special attention was the substantial change in the determination and disposition of Trade Income. Trade Income is defined as the audited net income of Powerex. A significant change to the amount that may accrue to Government arises by virtue of an agreement between BC Hydro and Powerex ("The Transfer Pricing Agreement for Electricity and Gas"). The effect of this agreement is that Trade Income will no longer include revenues from the sale of surplus power, except for a profit expected to be realized by Powerex after paying BC Hydro an indexed price for surplus power. All Trade Income between $0 and $200 million accrues to the ratepayers. Because of its importance, three alternatives to BC Hydro's proposal for Trade Income are discussed in this Report.

The Report recommends BC Hydro's Trade Income proposal, with an additional recommendation for an incentive mechanism for Powerex, which would require approval by the Commission.

After the Heritage Contract, the second major area addressed in this Report is the design of a stepped rate structure for large commercial and industrial customers. The objective of such a system is to ensure the benefit of relatively low-cost energy through a Tier-1 block rate while reflecting higher cost of new supply in the Tier 2 block rate. The Report concludes that achieving the objectives of encouraging private sector investment in new supply and access by large electricity consumers to alternative suppliers is dependent on the success of stepped rates. This manifests itself in a recommendation that the Tier 2 rate should be based on the long-term costs and should be measured by expected acquisition costs.

This Report recommends implementation of stepped rates for large commercial and industrial customers and delineates principles for their determination. It further recommends concurrent implementation of time-of-use rates. Recognizing the innovative nature of stepped rates, the Report recommends a subsequent evaluation report to the Government.

The Energy Plan states that it is to be implemented by the end of 2004. Therefore, this Report identifies a schedule that has as its objective the implementation of retail access by the end of 2004.

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1 INTRODUCTION

This Report is the culmination of a Commission Inquiry that had its genesis when the BC Government articulated its new energy policy with the release of its Energy Plan late in 2002. This chapter provides a background summary of the policy, terms and process under which the Commission completed its Inquiry in order to provide its recommendations relating to a Heritage Contract, Stepped Rates and Transmission Access.

1.1 Energy Plan

On November 25, 2002 the Provincial Government announced its new Energy Plan, "Energy for our Future: A Plan for BC". The Energy Plan is the result of more than one year of work by the Energy Policy Task Force and further review within Government. An interim report was produced by the Task Force in November 2001 and the final report was submitted on March 15, 2002. Appendix 1 of the Energy Plan lists the Energy Policy Task Force recommendations and provides the Government's response to each.

The stated purpose of the Energy Plan is "to build on the province's energy strengths, in particular our abundant natural resources and low electricity prices, to help revitalize the economy and create jobs in an environmentally responsible way."

The Energy Plan is based on four cornerstones:

- **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**.

  Stable and dependable energy supplies are increasingly vital in the move to an information economy. To sustain our resource industries and expand the technology sector, energy reliability will be improved and energy markets will be diversified, with more sources of supply, greater competition in electricity generation and enhanced customer choice.

- **More private sector opportunities**.

  The private sector will be a key partner in the province's energy future. New investment in private power production and continued high activity levels in the oil and gas industry will be critical to realize our full potential as a leading energy supplier in North America.

- **Environmental responsibility and no nuclear power sources**.

  BC has a history of environmentally responsible energy development and one of the best environmental records on the continent. We continue to reject nuclear power and will build on our clean energy strengths with incentives for alternative energy development, new rate signals to encourage energy saving and aggressive strategies for conservation and energy efficiency. (Energy Plan, p. 13)

The Energy Plan establishes 26 "Policy Actions" designed to accomplish the objectives of the Plan over the next two years, of which the BC Utilities Commission ("Commission", "BCUC") is involved in at least 14.

The Energy Plan provides the context for this Inquiry. The BC Hydro and Power Authority ("BC Hydro, Utility") rate freeze has expired and BC Hydro has returned to active regulation by the Commission. BC Hydro is being divided into three distinct functional entities: generation, transmission and distribution. BC Hydro Distribution is to operate as a separate line-of-business from BC Hydro Generation, and a new publicly-owned entity, the British Columbia Transmission Corporation ("BCTC"), is expected to be responsible for planning, operating and managing the transmission system.

Specific Policy Actions in the Energy Plan anticipated a Commission Inquiry into a Heritage Contract, Stepped Rates and Transmission Access. Policy Action #1 directs the implementation of a legislated Heritage Contract that will essentially lock in the value of existing low-cost generation assets for the benefit of all BC Hydro ratepayers. The term of the Heritage Contract will be for ten years initially, with terms for renewal. The Commission is to recommend the terms and conditions for the heritage energy based on average water conditions, and a return on equity to BC Hydro consistent with that of privately-owned utilities. Policy Action #5 explains the re-regulation of BC Hydro rates and states that the Commission will conduct an Inquiry to develop and refine policy areas prior to a rate hearing.

Policy Action #2 states that an appropriate level of electricity trade revenue will continue to be assigned for rate-setting purposes to help maintain low and stable rates for BC consumers. Policy Action #13 restricts BC Hydro Generation to efficiency improvements and capacity upgrades at existing facilities, with the private sector to develop new electricity generation.

Policy Actions #14 and #21 propose a new stepped rate for transmission voltage customers to provide them incentives to purchase from independent power producers ("IPPs"), to self generate and to use electricity efficiently. Under Policy Actions #15 and #16, the Commission is to establish transmission rates and access conditions to allow IPP participation in U.S. wholesale markets and to provide non-discriminatory access to the transmission system.

1.2 Terms of Reference

On March 25, 2003 the Provincial Government issued Order-in-Council No. 0253, directing the Commission to convene a public inquiry and provide recommendations relating to a Heritage Contract for BC Hydro's existing generation resources, and relating to Stepped Rates and Transmission Access. With specific reference to Policy Actions #1, #2, #5 and #21, the Terms of Reference, attached as Schedule A to Order-in-Council No. 0253, state:

> The general purpose of the inquiry is to obtain the Commission's Recommendations on what changes, if any, should be made to legislation, regulations, special directions or special directives affecting BC Hydro and/or the Commission in order to implement the Energy Plan in connection with the issues identified in paragraphs 3 and 4 of these Terms of Reference.

Paragraphs 2 and 3 of the Terms of Reference relate to the Heritage Contract. Paragraph 2 states that the Commission shall make recommendations concerning the terms and conditions which should be contained in a Heritage Contract. The subsections of Paragraph 2 set out the assumptions that the Commission should use in making its recommendations. Paragraph 3 states that, with respect to a Heritage Contract, the Commission will make specific recommendations relating to several matters regarding the Heritage Contract. The subsections of Paragraph 3 outline the specific issues.

Paragraph 4 states that the Commission shall make specific recommendations relating to any changes it believes are desirable in the rates of transmission voltage customers to accomplish the objectives set out in the Energy Plan, including the terms and conditions for transmission and generation access from other suppliers, and provisions for stepped rates.

Paragraph 6 requires that the Commission solicit proposals from BC Hydro with respect to detailed recommendations and reasons that BC Hydro believes should be contained in the Commission's report. The Commission is to submit a report to the Lieutenant Governor in Council ("LGIC") listing its Recommendations and Reasons for the Recommendations no later than October 17, 2003. A copy of the Order-in-Council and the Terms of Reference are attached in Appendix A.

1.3 Commission Proceedings

Initial Proceedings and BC Hydro Proposals

Pursuant to Paragraph 6 of the Terms of Reference, the Commission issued Order No. G-23-03 on April 3, 2003 directing BC Hydro to file by April 30, 2003 a proposal identifying the detailed recommendations that BC Hydro believes should be contained in the Commission's report to the LGIC. The Order included a regulatory agenda and timetable for registration of intervenors and for the scheduling of a workshop, pre-hearing conference and public inquiry.

BC Hydro had previously held an information session and workshop on March 5, 2003 to explore Stepped Rates and Access Principles with potential intervenors in the proceedings. BC Hydro stated that the purpose of the workshop was to present a number of rate design parameters that meet the objectives of the Energy Plan, to identify some key implementation issues and to solicit input from customers to assist BC Hydro in framing its stepped rates proposal. Following the presentation, BC Hydro sought reaction from the participants on various aspects of the proposal and posed a number of issues for discussion. On March 14, 2003 BC Hydro distributed a summary of the workshop proceedings to all participants. Several intervenors provided written comment on the presentation and offered further suggestions on the proposal.

BC Hydro filed its Proposal regarding a Heritage Contract, Stepped Rates and Access Principles ("Proposal") in two volumes on April 30, 2003. Volume 1 (Ex. 8) outlines a proposal for a Heritage Contract between BC Hydro Generation and BC Hydro Distribution. Volume 2 (Ex. 8-1) introduces BC Hydro's submissions on stepped rates and access principles for transmission voltage industrial and large commercial customers. The Proposal became a point of departure for intervenors to discuss refinements or alternatives that they felt would better satisfy the Inquiry's Terms of Reference. Intervenors filed their initial submissions to the Inquiry on June 6, 2003.

BC Hydro states that its Heritage Contract Proposal is designed to meet two key policy objectives of the Energy Plan: secure, reliable supply and low electricity rates. BC Hydro believes that the ownership and operation of the Heritage Resources by BC Hydro is intended to benefit all classes of customers for an extended period. Accordingly, the Heritage Contract Proposal is designed to ensure that all customers continue to benefit from the operational flexibility that BC Hydro's large hydro storage capacity permits and that customers pay for supply on an embedded cost basis. BC Hydro proposes a deferral account to smooth the impact on ratepayers from variations between the forecast and actual revenue derived from the Heritage Resources each year. Volume 1 of the Proposal includes a method for calculating net income from trading activities ("Trade Income").

Volume 2 of the Proposal deals with changes BC Hydro believes are desirable in the rates of transmission voltage customers to accomplish the objectives set out in the Energy Plan, including stepped rates and access to transmission to allow the delivery of power from other suppliers. BC Hydro states that stepped rates provide an opportunity to encourage customers and privately-owned suppliers to make new investments that are beneficial to the province, while preserving the benefits of low embedded cost rates. BC Hydro believes that a suitably designed stepped rate can help achieve the policy objectives in the Energy Plan and enable BC Hydro customers and IPPs to make mutually beneficial direct access arrangements.

BC Hydro adopted three guiding principles: the stepped rate should be a mandatory tariff; the stepped rate should be revenue neutral at historic consumption levels; and the stepped rate should remain “margin neutral” at all consumption levels. BC Hydro believed that it was premature to propose a stepped rate beyond a design based only on principles without consulting further with customers because many aspects of the design, and the options it should include, would depend upon customer preferences that were not yet fully understood. Accordingly, in the cover letter to its April 30, 2003 Proposal, BC Hydro stated that it believed progress could be made on stepped rates and access principles if consultation with stakeholders continued. The Commission Panel agreed that further consultations would be useful. The Commission wrote to BC Hydro on May 22, 2003 advising that the Commission Panel was directing Commission staff to convene meetings to consider alternative new rate structures that may meet the objectives of the Energy Plan. Intervenors interested in stepped rate issues met on May 27, June 3, June 4 and June 13, 2003. Participants agreed that the meetings were intended to facilitate full and frank discussion, would be on a without prejudice basis, and would not be used to attribute positions to specific parties. Commission staff prepared a summary of the discussions and distributed it to participants.

On June 27, 2003 BC Hydro filed with the Commission a further proposal regarding Stepped Rates and Access Principles (Ex. 8-2). In the background to the further proposal, BC Hydro stated that the discussions and the Commission staff summary provided them with a greater understanding of the interests of the stakeholders, and that it was then able to elaborate further its views with respect to stepped rates. These were then incorporated into BC Hydro’s April 30 Proposal.

A pre-hearing conference was held on July 7, 2003 before the Commission Panel. This was intended to give all parties the opportunity to make submissions on the issues that they believed should be canvassed at the public hearing. The Commission Panel also heard submissions on scheduling matters.

On July 9, 2003 the Commission issued a letter to all participants providing procedural information to the oral public hearing phase of the Inquiry, a revised and updated intervenor list, a revised and updated issues list and draft pre-filed Exhibit list. The letter also addressed questions and issues that arose during the pre-hearing conference and provided for further comment or questions from participants.

Regional Public Hearings

The oral phase of the Inquiry began with three one-day public hearings in Victoria, Prince George and Kelowna on July 21, July 23 and July 25, respectively. These sessions allowed interested parties from outside the Lower Mainland an opportunity to provide direct input to the Inquiry Panel. Several individual participants expressed concerns about deregulation of the electric system and commented on the unique role that the low embedded cost hydroelectric system plays in British Columbia.

The Regional District of Alberni-Clayoquot ("Alberni-Clayoquot") raised concerns that limitations on access to more power on Vancouver Island limits new industrial development there, and argued that the transmission of power on the existing grid should be included in the Heritage Resources and therefore included in the rates (Ex. 13). Alberni-Clayoquot further argued that the downstream benefits associated with the Columbia River Treaty should be directed to the Heritage Beneficiaries for domestic use, and that heritage power and any surplus power should be used to encourage new industrial customers within the province (T1: 50-55).

The Peace River Regional District ("PRRD") noted the substantial role that its region has in provincial electricity supply. It submitted that affordable extensions to the distribution system were a principal requirement for development of the region, but that the cost of rural extensions excluded some individuals or communities from receiving BC Hydro service. The PRRD supports the establishment of the Heritage Contract to preserve and maintain in perpetuity the entitlement to the low embedded cost electricity. It also sought the assurance of the Commission that implementation of the Heritage Contract would ensure that BC Hydro would be required to maintain and ensure adequate voltage and service quality (T1: 99-113). The North Central Municipal Association ("NCMA") strongly supports the principle of postage stamp (uniform) rates across the province, as does the PRRD. The NCMA also supported the PRRD submission with respect to the need for a policy of affordable extensions to the electrical system, and recommended that the Heritage Contract provide for a fund of $3 million per year for system extensions. The NCMA expressed concerns about stepped rates due to the difference in heating requirements between the northern and southern parts of the province, and submitted that stepped rates and rate design should be subjected to thorough analysis before implementation (T1: 121-123).

In Kelowna, the Interior Municipal Electrical Utilities group ("IMEU") submitted that, while it supported the direction of the Energy Plan, it believes that the term of the Heritage Contract should be considerably longer than contemplated by the Energy Plan (T1: 206). The IMEU supports an initial minimum term of fifty years, a position that was also supported by Ms. Parsons at the same regional session (T1: 210). The Thompson-Nicola Regional District ("TNRD") supports the four cornerstones of the Energy Plan and submits that the Heritage

Rates should be available to the TNRD region subsequent to the closure of Highland Valley Copper as an incentive to industry to locate in the region. The TNRD raised concerns that the stepped rate will act as a deterrent to new or expanding industries, and suggested that, as an alternative, industrial rates might be tied to the energy efficiency of the operation (T1: 238-241).

The Commission Panel also received submissions from Norske Skog Canada, Kemess Mines, and Highland Valley Copper at the Regional Inquiry sessions. The industrial Intervenors who appeared at the Regional Sessions generally supported the position of the Joint Industry Electricity Steering Committee ("JIESC") in the Inquiry.

Vancouver Public Hearing

The hearing continued in Vancouver for nine days between July 28 and August 13, 2003. Thirteen intervenor groups actively participated in the Vancouver sessions. BC Hydro presented three panels of witnesses in support of its Proposal and four intervenor groups provided panels of witnesses (see Appendix F). The hearing was followed by written argument and rebuttal. A further one-day session on September 5, 2003 allowed counsel an opportunity to respond to questions from the Commission Panel on the final submissions.

1.4 Structure of the Report

Chapter 2 summarizes the components of BC Hydro's Heritage Resources. Chapter 2 also discusses BC Hydro's Proposal and an alternative proposal by CBT Energy Inc. ("CBTE") for conferring the benefits of these resources to the ratepayers of BC and to the shareholder of BC Hydro, as directed in the Energy Plan and in the Terms of Reference. Chapter 3 discusses the merits of alternative stepped rate designs and the Commission Panel's conclusions regarding the anticipated performance of alternative designs for achieving the objectives of the Energy Plan, following the intent of stepped rates. Chapter 3 includes a discussion of the applicability of stepped rates to non-industrial customers, as well as a review of time-of-use rates. Chapter 4 discusses the details of transmission access to third party supply. Chapter 5 concludes the Commission Panel's Report with all the Commission Panel's recommendations to the Government, including its determinations on the scheduling of future filing, insofar as such issues have stemmed from this Inquiry.

2 HERITAGE CONTRACT

2.1 The Heritage Resources

BC Hydro owns and operates the Heritage Resources and sells the electricity output domestically through the coordinated operation of the generation, transmission and distribution systems. A BC Hydro subsidiary, Powerex, markets surplus BC Hydro electricity and engages in substantial energy trade outside the province.

Prior to August 1, 2003 BC Hydro's Grid Operations division operated the transmission system separately from the rest of BC Hydro. On August 1, a separate company, the British Columbia Transmission Company ("BCTC"), assumed responsibility for managing, maintaining and operating the transmission assets, which continue to be owned by BC Hydro.

The Terms of Reference specify that the Heritage Contract is to include all the BC Hydro generation resources, as well as the rights and obligations indicated in Schedule A of the Terms of Reference. The "heritage electricity" produced by the Heritage Resources is comprised of energy, capacity, and ancillary services. BC Hydro's Annual Financial Report to the Commission, filed July 31, 2003, revealed that 48,667 gigawatt hours ("GWh") of generating energy were required for domestic consumption. By contrast, 31,182 GWh were involved in electricity trade by Powerex.

Quantity

Energy

The Terms of Reference stipulate that the specific quantity of energy to be included in the Heritage Contract is the quantity producible from the Heritage Resources assuming average water conditions for the duration of the Heritage Contract. In its Proposal, BC Hydro used historical average generation from the Heritage Resources and conducted simulation studies of future average generation from these resources to determine the appropriate quantity of heritage energy. The analysis estimates a quantity of energy equal to 49,000 GWh (supplied at the generator). Of this total, heritage thermal resources accounted for 2,400 GWh, the expected thermal generation requirement under average water conditions.

The Independent Power Association of British Columbia ("IPPBC") questioned BC Hydro's calculation of the 49,000 GWh (Ex. 27, p. 7, IPPBC Final Argument), and contended that the amount should be set at 45,715 GWh (or 46,000 GWh) which is the amount BC Hydro provided as the actual hydroelectric average generation over the period 1985-2002.

Capacity

The Heritage Resources have an installed capacity of approximately 11,000 MW, of which hydroelectric installations account for approximately 10,000 MW. The Terms of Reference state that capacity considerations should be incorporated into the Heritage Contract. The forecast peak demand on the BC Hydro system for 2003/04 is 9,745 MW, which is well within the maximum capacity of the Heritage Resources, but only 55 MW less than the installed hydroelectric capacity component of 10,000 MW. As a 100 percent utilization factor of all the heritage hydroelectric facilities is not achievable, the peak load will have to be met by the operation of Burrard or purchases from private producers.

Ancillary Services

Ancillary services are services required to permit the reliable transmission of electricity from the generation sources to the points of delivery on the BC Hydro transmission system. Included in these services are scheduling, system control and dispatch, reactive supply and voltage control, regulation and frequency response, energy imbalance, operating reserve and compensation for transmission losses.

On the BC Hydro system the primary sources of ancillary services are the hydroelectric Heritage Resources, particularly those on the Peace and Columbia rivers. These services are required by BC Hydro Distribution for supplying power to its domestic customers, by Powerex for its export activities, and by any other entity using the transmission system. BC Hydro self-supplies ancillary services pursuant to the terms of the Wholesale Transmission Service ("WTS") tariffs.

BC Hydro submits that the use of the Heritage Resources for ancillary services, except for scheduling, system control and dispatch, may limit the surplus capability of the system that is available for electricity trade. This situation may also hold true for ancillary services supplied to third parties under the WTS tariff. Presently, these services are provided at embedded cost, which may be less than the cost of the BC Hydro's purchases undertaken concurrently with the sale of those services. BC Hydro also submits that the revenues it receives from the sale of ancillary services would be included with other revenues that reduce the Heritage Payment Obligation ("HPO") of BC Hydro Distribution (T5: 1024; Appendix B, Schedule A).

Energy Shaping, System Coordination and Scheduling Flexibility

Efficient operation of the Heritage Resources to optimize electricity output and the economic value of the resources involves astute coordination of the Heritage Resources to manage the "shape" of the energy from the system, to maximize flexibility in the scheduling of these resources and to achieve economic gains. Output from the Heritage Resources can be limited by operational considerations such as inefficiencies brought on by the deterioration of plant facilities, constraints on reservoir water levels or water release requirements.

Energy shaping results from actions of the generator to vary generation output over time in order to improve overall efficiency of operation. The large capacity storage reservoirs associated with the hydro Heritage Resources provide substantial opportunity for energy shaping. The distribution entity can assist in optimizing system efficiency by minimizing significant variations in load shape, variations which could otherwise diminish the reliable supply capability of the generators.

System coordination in the context of the Heritage Contract involves the coordinated operation of the generation and distribution lines of business collaborating with the operation of Powerex. The coordinated use of generation from Heritage Resources, purchases from IPPs and strategic market purchases or sales, generally leads to system optimization and increased benefits for all participants.

Scheduling flexibility relates to the ability of the generator at any point in time to make a determination as to the source of the energy to be delivered to the distributor. BC Hydro's normal choice is whether to generate electricity from its own hydro resources or obtain it from elsewhere and retain water in the reservoir for later use when it might be more valuable.

Upgrades and Additions at Existing Heritage Facilities

At some heritage sites, Resource Smart undertakings, primarily turbine efficiency improvements on generating units, will augment the energy generating capability of the units worked on, creating incremental increases to the heritage electricity.

Some participants at the Inquiry raised the issue of the future installation of Units 5 and 6 at both the Revelstoke and Mica generating stations. BC Hydro interprets the Terms of Reference to preclude the inclusion in the Heritage Resources of any incremental capacity increases resulting from a material change to existing facilities at any of the power stations. BC Hydro testified that it believes that Mica units 5 and 6, and Revelstoke units 5 and 6, do affect the productive capability of those resources in a material way and that, therefore, the Terms of

Reference imply that the Heritage Contract should not be amended for those capital investments (T4: 811).

Others argue that since most of the basic civil infrastructure (constructed at the time the other four units were installed) was already in place for these future additional units, this portion of the original cost is, and will continue to be, borne by ratepayers. Therefore, they believe that installing the turbines, generators and auxiliary equipment for these additional units should not be classified as completely new installations, and should be considered for inclusion in the mix of Heritage Resources.

However, BC Hydro submits that, even if it developed these projects outside of the Heritage Contract, the way that it is currently regulated, those benefits that it would receive from development of those projects would still go back to the ratepayer, because those revenues would be consolidated with all other revenues (T4: 813,814). In BC Hydro's view, it could be a moot point whether such projects are developed inside the Heritage Contract or outside the Heritage Contract, because under the BC Hydro proposal the ratepayers would pay for the costs of these additions, whether or not these units become part of the Heritage Resources.

BC Hydro believes that developing these projects outside the Heritage Contract would require Commission approval. BC Hydro believes that if its Generation and Distribution revenues remain consolidated, there would be no benefit in developing such projects outside the Heritage Contract. Under those circumstances, BC Hydro would simply apply to the Commission to have the Heritage Contract amended to include those resources.

Electricity Supply Costs

The Terms of Reference require the Commission to make a recommendation concerning the cost of supplying the quantity of energy under the Heritage Contract. The costs related to the supply of electricity from the Heritage Resources include energy costs, operating costs, and accounting and financing costs.

Energy Costs

Energy costs include water license fees, fuel and transportation costs for thermal generation, and electricity purchases from third parties.

Water license fees (water rental) are paid to the Province for the use of water by the hydroelectric system. The fees are a function of the capacity of the generators and the actual energy generated. The capacity charge is \$3.453/kW and the energy charge is \$1.036/MWh for the first 160,000 MWh and \$4.835/MWh for all additional generation. These rates are indexed to BC Hydro's rate schedules ("RS").

Two significant components of the cost of thermal generation are the cost of natural gas and the cost of transporting the gas to the plant.   Purchases from third parties are necessary to meet demand when the Heritage Resources are unable to supply the quantity needed, or when it is more economical to make such purchases than to generate from the Heritage Resources. BC Hydro’s decision on whether to generate or to purchase power will depend on the market price of power versus the cost of BC Hydro generation, including the benefits of storing water for future hydroelectric generation and the cost of fuel and transportation for thermal generation.

Operating Costs

Costs associated with the operation of the Heritage Resources are primarily plant maintenance and plant operation costs. Maintenance costs are servicing costs (labour and materials) required to maintain the Heritage Resources in sound working condition, and to repair or refurbish facilities as they break down or deteriorate. Since some Heritage Resources are several decades old, accurately forecasting these costs is very difficult. Operating costs are labour costs associated with the day-to-day operation of the generating plant facilities for the production of electricity and ancillary services. Secondary costs include environmental, regulatory and certain management costs that are required to maintain the licenses for use of the water.

Accounting and Financing Costs

Accounting costs include asset related expenses, return on equity, Generation Related Transmission Assets (“GRTA”) expenses, and business sustaining costs.

Asset related expenses include depreciation and amortization, taxes and grants, and finance costs, less interest during construction. Depreciation and amortization expenses are directly related to the value of the capital assets in service, and the expected useful lives of these assets. Taxes and grants are paid to the Province and municipalities based on the assessed value of the properties involved. This payment is in lieu of all general, local improvement and regional district levies. Finance costs less interest during construction primarily relate to interest on debt securities, amortization of deferred debt costs, less the income from sinking funds and interest during construction.

Special Direction No. 8 (“SD8”) to the Commission allows BC Hydro to earn a Return on Equity (“ROE”) equivalent to that granted to the most comparable utility. BC Gas Utility Ltd. was selected as the most comparable utility by the Commission in its November 24, 1994 Decision concerning BC Hydro’s 1994/95 Revenue Requirement application.

The JIESC noted that SD8 defines equity as the sum of the retained earnings and deferred credits at the end of the financial year. The definition of deferred credits is the sum of the Rate Stabilization Account ("RSA"), deferred revenue, contributions arising from the Columbia Treaty and contributions in aid of construction. The JIESC also expressed concern that SD8 converted deferred credits such as customer contributions, which would normally be zero cost capital for other utilities, into equity in the case of BC Hydro.

The JIESC proposed that SD8 be amended to eliminate deferred credits from the definition of equity, and to allow the return on the Heritage Resources to be determined and calculated by the Commission in the same manner as for other utilities in the province. The JIESC also proposed that any necessary adjustments be phased in over time (T2: 332; JIESC Final Argument, p. 14).

BC Hydro has proposed certain amendments to SD8 and Special Directive No. 4 ("SD4") as the appropriate means to give legislative credibility to the Heritage Contract. The changes proposed for SD8 would terminate the RSA. Accordingly, BC Hydro has advised that it would not be seeking equity earnings on its proposed Heritage Deferral Account ("HDA") (T3: 542), as was the case with the RSA.

In a 2002 Decision, the Commission allowed BC Gas an after-income tax ROE of 9.42 percent for 2003. BC Hydro has converted this into a pre-income tax figure of 14.33 percent. BC Hydro has allocated the sum of \$1,073 million as the equity value of the Heritage Resources for fiscal 2004. This value has been determined as follows:

- Deferred revenue from the Skagit Value Treaty $279 million
- Deferred charges from the Columbia River Treaty $202 million
- Allocation of BC Hydro retained earnings $592 million

Using the 2003 rate of 14.33 percent, the ROE costs would amount to \$154 million (\$1,073 million x 14.33 percent).

GRTAs are those transmission facilities that link remote generation to the first interconnection point. Based on the provisions of the Commission's 1998 Wholesale Transmission Service Decision, BC Hydro has determined that the GRTA costs for the purposes of the Heritage Contract should be $43.3 million. This amount represents the difference between BC Hydro's total "transmission revenue requirement" and the smaller portion of the "transmission revenue requirement" reflected in current wholesale transmission rates (Ex. 8, Appendix F5). BC Hydro has proposed that this GRTA amount be fixed for the duration of the Heritage Contract, and that it not be associated with any specific set of assets.

Business sustaining costs relate to corporate services and costs collected at the corporate level that are allocated between BC Hydro's lines of business. The allocations are based on headcount, operations, maintenance and administration expenditures, sustaining capital expenditures and usage of corporate buildings (Ex. 8, Appendix F4).

Factors Impacting the Cost of Heritage Electricity

Since the Heritage Resources are about 90 percent hydroelectric, and therefore subject to weather variations, their generation output cannot be assured. Therefore, during the term of the Heritage Contract, BC Hydro anticipates occasions when the Heritage Beneficiaries will be partially supplied form external sources. Several factors can change the quantity and cost of heritage electricity, including:

- Changed circumstances such as an extended period of below-normal inflows in the heritage reservoirs;
- Fluctuations in the price of energy purchases by BC Hydro Generation (examples include a prolonged period of forced operation of Burrard Thermal at high gas prices, or having to purchase electricity from the market at inflated prices);
- Unplanned capital maintenance; and
- Unexpected occurrences such as rapid fluctuations in currency exchange rates or interest rates.

The form of the Heritage Contract will influence the relative impact of these factors on BC Hydro's rates and the return to its shareholder.

Revenue Earned by the Heritage Resources

Revenues earned by the Heritage Resources serve to offset the overall revenue requirement of BC Hydro. Apart from the requirements of the Heritage Beneficiaries, additional services are provided from the Heritage Resources that generate revenues. These include the following:

- Services supplied under the Skagit Valley Treaty (approximately $25 million annually for delivery of approximately 340 GWh);
- Revenues from the provision of ancillary services to the transmission operator to accommodate third party use of the transmission system (approximately $3 million annually);
- Revenues from the sale of surplus hydroelectricity;
- Revenues from Trade Income; and
- Miscellaneous revenues such as the sale of water to the Greater Vancouver Regional District from the Coquitlam reservoir, and the sale of steam from the Burrard Thermal Plant (BC Hydro estimates this revenue at between $1 and $3 million).

Electricity trade is an important aspect of the operation of the BC Hydro system and results from the activities of Powerex, activities which are supported by the Heritage Resources. The Terms of Reference direct the Commission to address the allocation of Trade Income.

2.2 Structure of a Heritage Contract

One potential model for a Heritage Contract follows common regulatory treatment of utilities, in which the utilities provide services to ratepayers and collect in return an approved "revenue requirement" comprised of the costs of providing those services, including a return to the shareholder. For this reason, the model was termed the "Revenue Requirements model" during the Inquiry. An important feature of this model is that the benefit received by ratepayers at any point in time is only constrained by the capability of the resources (and the $200 million cap on Trade Income) and the amount paid by ratepayers is directly related to the cost of providing the power. Both the benefit received by ratepayers and the cost paid by them will fluctuate over time as the capability of the resources change (due to fluctuating water inflows for instance), and as costs change.

Another model that was extensively investigated related to a fixed (i.e. predetermined) quantity of electricity and an associated fixed price to consumers. This was designated the "Fixed Price/Fixed Quantity" model. The Fixed Price/Fixed Quantity model prescribes a fixed price and a fixed quantity of electricity to be delivered under the Heritage Contract that would be locked in for a specified period of time. Quebec instituted this model, pursuant to an Order-in-Council issued in 2001. It was a means of locking-in benefits from Quebec's heritage generation facilities for an extended period by means of a contract between the Hydro-Quebec Distribution business unit and the Hydro-Quebec Production business unit, which manages that utility's generation resources. The Energy Plan referenced the Quebec arrangement with the statement "The heritage contract is similar to arrangements that have been adopted in Quebec" (p. 26).

As future costs and prices are very unpredictable, the Fixed Price/Fixed Quantity model would normally be associated with various kinds of risk premiums, to compensate the generator and its shareholder for assuming the risk of revenue requirement shortfalls during periods of unexpected reductions in the generation output at the heritage plants. Even though risk premiums are common with this model, contract re-openers tend to be incorporated as well, to hedge the generator against significant unexpected costs or inadequate risk premiums.

2.3 BC Hydro Proposal

BC Hydro proposes a Revenue Requirements contract structure under which ratepayers receive all the benefits of the Heritage Resources (up to the $200 million limit on Trade Income) and pay the full costs or revenue requirement of the Heritage Resources. The contract structure treats the costs of the generation and distribution lines of business of BC Hydro similarly by returning them both to regulation by the Commission for periodic review. Rates would be based on the prudently incurred costs of the Utility required to provide safe, reliable service. Cost or earnings variances from those forecast would be placed in an HDA to record any differences between forecasts of the HPO and the actual HPO to assist in keeping rates stable over time.

Heritage Contract Provisions

As guided by the Terms of Reference, the Heritage Contract would specify the electricity supply obligations of BC Hydro Generation and the payment obligations of BC Hydro Distribution in respect of the electricity supplied from the Heritage Resources. Under BC Hydro's proposal, BC Hydro Distribution would have a priority call on the Heritage Resources up to the maximum capacity available, as required to serve its customers. Any surplus capacity may be made available to Powerex pursuant to the terms of the Transfer Pricing Agreement.

BC Hydro has determined from historical information and simulation studies that the maximum reliable capability of the Heritage Resources under average water conditions is 49,000 GWh per year. It defines this amount as the "Heritage Energy". BC Hydro does not specify any limits on capacity other than the capacity available from the Heritage Resources.

The heritage electricity (the combination of heritage energy, capacity and ancillary services) is to be provided to BC Hydro Distribution based on the embedded costs of the Heritage Resources. The load requirements of customers will be supplied by the hydro Heritage Resources, supplemented (if necessary) by operating thermal Heritage Resources and purchasing from third party suppliers.

BC Hydro refers to the heritage electricity supply obligation in the Heritage Contract as the "Heritage Supply Obligation" ("HSO"). The payment obligation in the Heritage Contract for the supply of the heritage electricity is the HPO.

In the BC Hydro Proposal, the heritage energy component of the HSO (49,000 GWh) is illustrative. BC Hydro does not intend to place a rigid cap on the amount of energy provided to Heritage Beneficiaries in any given year.

The Utility has clarified that the total output of all the Heritage Resources will be at the disposal of the Heritage Beneficiaries. On that account, BC Hydro does not specifically intend to include this exact amount in future revenue requirements applications (BC Hydro response to BC Old Age Pensioners' Organization *et al.* ("BCOAPO"), IR#1.5.2).

The capacity component of the HSO would be a bundled service consisting of the full capacity of the Heritage Resources, as well as generation shaping and scheduling flexibility as required, to optimize the operation of the system. The ancillary services component of the HSO would be supplied from the Heritage Resources by BC Hydro, and would not be an additional cost to the Heritage Beneficiaries.

BC Hydro indicates that other rights and obligations, primarily those under the Skagit Valley Treaty, could impact the HSO quantity. Under the Skagit Valley Treaty, BC Hydro has to deliver from heritage energy an amount of 340 GWh annually to Seattle City Light.

The essential components of the HPO include the cost of energy, operating costs, asset related expenses, GRTA costs, and ROE, less other revenues. Some of these costs can be predicted with reasonable accuracy, while others may be very volatile and could depend on factors that can change significantly over time. Table 1 is taken from a BC Hydro forecast (Ex. 8, pp. 41-42) of the HPO for the first ten-year period of the Heritage Contract.

Table 1: Forecast Heritage Payment Obligation, 2005-2014 ($million)

	Reference	**Heritage Contract**			
	2004	2005	2007	2010	2014
Heritage Contract Costs					
Cost of Energy	$441	441	434	432	425
Operating Costs	162	158	166	166	166
Asset Related Expenses	380	370	392	430	467
GRTA Expenses	43	43	43	43	43
Total Heritage Contract Costs	*1,026*	*1,012*	*1,035*	*1,071*	*1,101*
Less Other Revenues					
Skagit Valley Treaty	(22)	(23)	(25)	(25)	(25)
Ancillary Services and Miscellaneous Revenue	(4)	(5)	(6)	(5)	(5)
Total Other Revenues	*(26)*	*(28)*	*(31)*	*(30)*	*(30)*
Net Costs	1,000	984	1,004	1,041	1,071
Add: Return on Equity	154	160	192	197	230
Forecast Heritage Payment Obligation	***1,154***	***1,144***	***1,196***	***1,238***	***1,301***

BC Hydro stated that the fiscal 2004 figures are for comparative purposes only, and that fiscal 2005 to 2007 are forecasts. Fiscal years beyond 2007 until 2014 have been extrapolated from fiscal 2007.

BC Hydro further stated that it developed the cost and revenue forecast shown in Table 1 using the same budgeting, planning and forecasting processes it uses to develop the five-year BC Hydro Service Plan, and its yearly internal line-of-business service plans. The only exception is that the cost of energy forecasts in Table 1 are based on the delivery of 49,000 GWh per year (Ex. 8, pp. 40-1).

To establish a context for future rate proceedings, BC Hydro has forecast that the cost of supplying the heritage electricity over the term of the Heritage Contract will average approximately $25.30/MWh (Forecast Heritage Reference Price). This price was derived using an average forecast value for the HPO over the ten-year period from 2004/05 to 2013/14, under average water conditions, without any contribution of Trade Income (Ex. 8, p. 9). BC Hydro noted that the $25.30/MWh was an illustrative number (T4: 834) and that under the Revenue Requirements model ratepayers would pay the actual cost, which would not necessarily be the same (T1: 88-9). BC Hydro also stated that a Fixed Price/Fixed Quantity contract to supply 49,000 GWh at an average price of $25.30/MWh for ten years would impose a very high level of risk on BC Hydro (T3: 514).

Table 1 indicates that the largest single component of the HPO is the cost of energy. The cost of energy is highly volatile due to varying water conditions from year to year. BC Hydro stated that because of this volatility, hydro energy production could vary +/- 5,000 GWh from the heritage energy amount of 49,000 GWh. The impact of such variation is that a 5,000 GWh surplus reduces the Heritage Reference Price to $19.00/MWh, whereas a shortfall of 5,000 GWh increases the Heritage Reference Price to $31.00/MWh. (Ex. 4-2, Pg.25). Therefore, water conditions have a significant impact on the unit cost of energy, and consequently the revenue generated.

Trade Income

Powerex trading activities are supported by the Heritage Resources and include several specific types of trades including:

- Trade between different locations and markets using transmission;
- Trade between time periods within the day and across seasons; and
- Market timing of forward purchases and sales, and forward marketing.

Powerex activities also include the purchase and sale of natural gas to accommodate BC Hydro's involvement with domestic thermal generation. Powerex acquires gas through a mix of spot and forward transactions and then supplies it to BC Hydro in specified quantities, at designated hubs, in return for an index-based price (Ex. 8, p. 25 and Ex. 78).

Trade Income is defined by SD8 as the audited net income of Powerex. As described by BC Hydro:

> …Trade Income will include the revenues Powerex receives from sales to third parties and to BC Hydro reduced by its costs of purchasing electricity from third parties and BC Hydro, its costs for use of BC Hydro facilities (including transmission), its payments to other utilities for transmission and other services and its own operating costs (Ex. 8, p. 11).

The audited net income of Powerex is to be calculated using generally accepted accounting principles as applied to transactions between Powerex and its trading partners, and associated transmission and other expenses.

Sub-paragraph 3(h)(ii) of the Terms of Reference specifies that up to a maximum of $200 million per year of trade revenue be allocated to BC Hydro and its customers, in a manner that provides rewards for the party that takes the risk associated with realizing those rewards while minimizing the expenses and delays associated with regulatory oversight of activities relating to trade. BC Hydro proposes that Trade Income up to $200 million per year be dedicated to the Heritage Beneficiaries, as an offset against BC Hydro's revenue requirement. Trade revenue in excess of this amount, as well as negative trade revenue, would accrue to the account of the shareholder (the Province, through BC Hydro). BC Hydro indicates that exceeding $200 million in trade revenue is unlikely since it is exclusive of surplus hydro sales, and it is only forecasting amounts of $75 million to $125 million in Trade Income per year.

BC Hydro proposes that export sales of surplus hydro energy should be excluded from Trade Income. Under BC Hydro's proposal, surplus hydro energy would be sold to Powerex at the index price and the profit realized by BC Hydro would be credited to the HPO for the benefit of ratepayers. Profits made by Powerex in such transactions would be the price premium realized above the market index price paid to BC Hydro and would accrue to Trade Income.

Transactions between Powerex and BC Hydro are governed by the provisions of the Transfer Pricing Agreement (Ex. 78), which specifies pricing mechanisms and the terms and conditions of all sales and purchases between these two entities (BC Hydro's Final Argument, pp. 10,11). BC Hydro's summary description of the operation of the Transfer Pricing Agreement is attached as Appendix I.

The Transfer Pricing Agreement (Ex. 78) also incorporates terms for the purchasing of transmission and ancillary services by Powerex to support its trading activities, and confirms that Powerex assumes exclusive rights to purchase and market the surplus electricity from BC Hydro. Powerex also procures electricity from the market to supply to BC Hydro whenever there is a shortfall in the local provincial supply and market conditions are suitable.

BC Hydro stated at the Inquiry that: "So long as the revenue requirement model that Hydro puts forward is in fact adopted, and therefore Powerex's net income is central to the model, then in Hydro's submission it follows that the Transfer Pricing Agreement should be on file with the Commission, and obviously a material change to it should be something the Commission considers before it happens" (T11: 2283-4).

BC Hydro contends that its Heritage Contract proposal maximizes the contribution of trade activity to the fixed costs of the system, and that the Trade Income allocation allows it to maximize the value of its system in a manner that is not only consistent with the Terms of Reference, but also avoids any operational and managerial conflicts for BC Hydro (Ex. 8, p. 27).

BC Hydro also notes that current regulatory oversight of all trading activity is minimal, essentially limited to the review of quarterly export trade reports filed with the Commission. BC Hydro stresses that the trading operation can only be efficient if it has the latitude and flexibility to adapt to changing market rules and circumstances, and maintains the ability to make timely decisions and focus on market conditions. Therefore, BC Hydro proposes that the current regulatory regime continue. As stated by BC Hydro:

> An efficient trading operation requires the flexibility to adapt to changing market rules and circumstances; an ability to make timely decisions; and a focus on market conditions. Each of these factors suggests that regulation of the trading function should be minimal. Moreover, trading success is best obtained by an alignment of interests amongst the marketing organization, its employees carrying out the trades, and the beneficiaries of successful trading. If the interests are aligned, pre- or post-activity regulation should be unnecessary. Accordingly the presence of unnecessary regulation would increase costs and hamper necessary flexibility. (Ex. 8, p. 31)

Heritage Deferral Account

Paragraph 1 of the Terms of Reference solicits recommendations from the Commission as to whether the RSA should be eliminated and, if so, whether it should be replaced with an "alternative form of deferral account mechanism". Accordingly, BC Hydro has proposed a HDA, intended to mitigate the impact of any variability in the revenue requirement. BC Hydro proposes that this account will capture the variances between the forecast and actual HPO and between the forecast and actual Trade Income (Appendix D, s.5.1).

BC Hydro notes in its Final Argument (p. 8):

> When significant short-term fluctuations in the actual cost of delivering energy from the Heritage Resources occur due to particular water or market conditions, the Heritage Deferral Account can smooth out the impact on customers by offsetting them against fluctuations in Trade Income and by bringing them into rates when it is convenient to do so.

The major source of volatility in the cost components of the HPO is the variability of water inflows in the heritage reservoirs. Since revenue requirement applications contain forecast costs, significant variances can occur when matched against the actual costs. Likewise, Trade Income is very unpredictable and subject to wide commodity price swings.

BC Hydro has therefore proposed the introduction of the HDA for the dual purpose of mitigating the expected annual volatility in revenue requirement, and as a replacement for the RSA. Benefits of this arrangement are that it can mitigate forecasting error and, by mitigating volatility, reduce the risk premiums required by the shareholder. These benefits assist in keeping rates low. BC Hydro expects the Commission will determine whether an adjustment to the HDA is required.

BC Hydro's Proposed Heritage Contract

The text of BC Hydro's proposed Heritage Contract is a brief three-page document containing information on Electricity Supply, Ancillary Services, Payment, Adjustment (to the terms of the Heritage Contract), Information Exchange and Cooperation, Dispute Resolution, Term and Termination, as well as a listing of the components of the HPO. Some parties argue that BC Hydro's proposed contract is insufficient and that a much more comprehensive document is required. BC Hydro argues that if the Revenue Requirement model is adopted, the proposed contract is sufficient in the regulatory context (BC Hydro Final Argument, pp. 13-14). That is, BC Hydro argues that a more comprehensive contract is unnecessary because of the regulatory structure implicit in the Revenue Requirements model. BC Hydro further suggested that its proposal could be effected through changes to SD8 and SD4 (BC Hydro Reply Argument, p. 8), and that the start date for the Heritage Contract should be set once the Government responds to the Commission Panel's recommendations.

In response to questioning by the IPPBC, BC Hydro said that specifying the capacity amount in the Heritage Contract would be harmful as it would unnecessarily constrain the provision of that capacity to the Distribution line-of-business (T4: 862). When asked how BC Hydro Distribution would be apprised of any capacity shortfall needed to supplement what was available from the Heritage Resources, BC Hydro replied that the Heritage Contract contemplated the free exchange of information on a regular basis between BC Hydro Generation and BC Hydro Distribution. BC Hydro stated that fixing energy shape or scheduling provisions in the Heritage Contract would also be constraining and that information exchange and cooperation is all that is required to adapt to those provisions. BC Hydro expects that information on plant operation, delivery priorities, and a system of metering would be discussed with the Commission and need not be hard-wired into the Heritage Contract (T3: 579, 580).

2.4 Intervenor Responses to BC Hydro Proposal

The BCOAPO generally supports the Revenue Requirements approach to a Heritage Contract because it provides for full Commission regulation of all aspects of BC Hydro and because it provides some flexibility in operating the system to maximize the benefits to customers (BCOAPO Final Argument, pp. 4-5). While the BCOAPO supports the concept of an HDA, it argues that the account should only cover BC Hydro's non-controllable costs. It argues that the components in such an account should be determined in BC Hydro's 2004 Revenue Requirements Hearing. The BCOAPO also notes that BC Hydro had indicated two available options for reviewing costs in the deferral account: at the time they were entered into the account, or at the time they were to be withdrawn from the account for recovery in rates (Ex. 46; BCOAPO Final Argument, p. 9). The BCOAPO also argues that the Commission Panel should recommend that SD8 be reworded to allow the Commission to both define equity compositions and determine the appropriate ROE consistent with the regulation of other utilities (BCOAPO Final Argument, pp. 8-10). Finally, the BCOAPO argues that the $200 million cap on Trade Income be adjusted annually for inflation.

The JIESC also recommended adoption of a Revenue Requirements approach to the Heritage Contract with specific details of the actual revenue requirement, the appropriate deferral accounts and appropriate performance-based regulatory structure to be determined in the next BC Hydro Revenue Requirements proceeding. In the view of the JIESC, the Revenue Requirements model clearly preserves the benefits of the embedded cost resources of BC Hydro for its customers through the use of an appropriate methodology for dealing with risk and the continued regulation of the Heritage Resources (JIESC Final Argument, p. 5).

The JIESC supports the Trade Income proposal by BC Hydro, and believes that the $200 million allocated to ratepayers is justified because the ratepayers are taking all the risk. The JIESC argues that this arrangement is appropriate because the ratepayers are bearing the cost of the facilities which will generate the Trade Income, and therefore they should receive the income.

The IPPBC supports the Revenue Requirements model, but does not support the recommendations of BC Hydro in the Heritage Contract with respect to the quantity of heritage energy under average water conditions (IPPBC Final Argument).

The CEC also supports a Revenue Requirements model and the position that the Heritage Contract supply the benefit of all of the energy, capacity and ancillary services of the Heritage Resources to the Heritage Beneficiaries (CEC Final Argument, p. 7, 9). The CEC proposes a start date of March 31, 2004. Aquila Networks Canada (British Columbia) Ltd. ("Aquila") and the University of British Columbia ("UBC") also supported the BC Hydro proposal for a Heritage Contract.

BC Citizens for Public Power and the Office and Professional Employees International Union ("BCCPP") oppose the implementation of the Heritage Contract as proposed. They believe that the Heritage Contract "….will place the entire burden of a dramatic shift in government policy squarely on the shoulders of the ratepayers" (BCCPP Final Argument, p. 8). BCCPP proposed a fixed rate for energy in the initial term of the Heritage Contract with no specific cap on the heritage energy supplied. In the view of BCCPP, any severe shortfall in revenue requirement could be mitigated by a deferral account in which all trade revenues would be allocated.

CBTE, which proposed a Fixed Price/Fixed Quantity approach to the Heritage Contract, did not support the BC Hydro proposal. CBTE based its opposition to the Revenue Requirements model primarily on its interpretation of the Energy Plan. In the view of CBTE, the Energy Plan was intended to mark a fundamental shift in the evolution of the electricity industry in BC and contemplates a Heritage Contract which "*locks in*" the price and quantity of electricity to be supplied to ratepayers from Heritage Resources, thereby "*entrenching*" benefits of the resources for ratepayers (emphasis CBTE's). CBTE argues that the Revenue Requirements model proposed by BC Hydro is simply a return to regulation in which the ratepayers assume all risks and the system benefits are neither locked-in nor entrenched (CBTE Final Argument, p. 2).

2.5 CBT Energy Proposal

CBTE proposes a Fixed Price/Fixed Quantity contract that fixes the amount of energy set aside in the Heritage Contract and the price the distributor is to pay for that quantity of energy (Ex. 16, p. 6). Under the CBTE proposal, BC Hydro Generation would independently manage the resources on behalf of the owner and would provide a fixed amount of energy at a fixed (i.e. predetermined) price. There would be no need to regulate BC Hydro Generation's activities. BC Hydro Generation would be entitled to use any energy that is surplus to the fixed quantity provided to BC Hydro Distribution under the Heritage Contract (Ex. 16, p. 10).

BC Hydro Distribution would be responsible for paying BC Hydro Generation the predetermined price for the quantity of heritage energy supplied under the Heritage Contract. BC Hydro Distribution would manage the Heritage Contract and would not be required to accept any energy above the quantity set in the contract. BC

Hydro Distribution would remain fully regulated and would procure new resources and act as the supplier of last resort. BC Hydro Distribution would be able to use the heritage energy only for native load; any unused portion of the contract quantity could be sold by BC Hydro Generation on behalf of BC Hydro Distribution for a commission of ten percent (Ex. 16, pp. 11-12).

CBTE submits that separation between BC Hydro Distribution and Generation is implied by Policy Action #8 and that the Fixed Price/Fixed Quantity contract proposed by CBTE provides the financial and operational separation called for in the Energy Plan (Ex. 16, p. 4; Ex. 24, pp. 1-3).

Initially, the Heritage Contract would provide for 49,000 GWh annually (based on the estimate in BC Hydro's proposal) to be supplied by BC Hydro Generation to BC Hydro Distribution. The capacity associated with this supply of energy is not to exceed 10,000 MW, inclusive of all applicable generation ancillary services. The CBTE proposal suggests that ratepayers pay a fixed unit price, set by the Commission on the basis of the levelized cost of the Heritage Resources.

CBTE proposes that the Commission review the Heritage Contract after five years and undertake a study to ensure that the evolution of the market is compatible with the goals of the Energy Policy. Additionally, a four-year notice period should be given prior to any adjustment in the Heritage Contract.

The Fixed Price/Fixed Quantity model would require the Commission to make an initial determination of the manner in which the shareholder is to be compensated for bearing the contract risk, and the magnitude of such compensation. CBTE proposes that the contract would be re-opened for reasons of force majeure or other extraordinary events.

In its initial June 6, 2003 submission, CBTE proposed that the quantity established in its proposed Fixed Price/Fixed Quantity model would decrease by one percent per year in order to compensate for potential risk associated with hydrology, market changes and other anticipated changes (Ex. 16, pp. 7). CBTE added that this annual reduction in the obligation would mitigate the risks related to the reduction in the productive capacity of the Heritage Resources as they age, and would compensate the generator for firming up the hydroelectric resources that are subject to natural variation in precipitation and changes in operational requirements (Ex. 16-2, p. 1).

CBTE also proposed that a premium be added to the levelized cost of the Heritage Resources in order to compensate the generator for taking volumetric and other risks. CBTE proposed that the Commission set the level of the premium and estimated that it should be between zero and five percent of the Heritage Price (Ex. 16, p. 8). The zero to five percent premium was meant to compensate the generator for risks associated with setting the price over 10 years, particularly risks related to the possibility of unanticipated increases over forecast costs for the 10 year period including such costs as operation and maintenance costs, taxes, water rentals, interest costs and gas costs (Ex. 16-2, p. 2). CBTE also indicated that risks could be addressed through a risk-adjusted ROE (Ex. 25, p. 3).

During the hearing, CBTE provided further analysis of the risk premium that should be attached to the price of a Fixed Price/Fixed Quantity contract (Ex. 16-5). The analysis is based on a probabilistic model incorporating the expected value of each input parameter and the variability attached to each parameter. Once bounds and profiles of the parameters are identified, along with the correlation between the parameters, the model will calculate the aggregate expected values and probability distributions using a Monte-Carlo simulation approach. CBTE used BC Hydro information where it was available, and other sources where it was not.

A highly significant variable in the model is the variability of water for hydroelectric generation and its impact on income. To incorporate this variable into the model, CBTE uses 60 years of water data, randomly selecting one year of the 60 as a base year and substituting the water data for the base year and the following nine years into the model for the years beginning in 2005 (T8: 1831). CBTE wished to determine the distribution of income around the revenue requirement (T8: 1826-1831).

Through multiple runs of the model, CBTE generated a series of probability curves for each one of the years of the proposed contract period. The probability analysis considered the possibility of some variables, such as the currency exchange rate, moving systematically in one direction over the ten-year period of the Heritage Contract. Such possibilities were included in the Monte-Carlo simulation of the model to produce more extreme outcomes of the probability distribution (T10: 2102).

CBTE's analysis indicates that the average annual variability over the length of the contract was approximately $70 million on a base revenue requirement of approximately $1.2 billion. CBTE's analysis suggests that, in the base case with no reduction in the energy requirement incorporated into the model, the probability of not achieving the average target revenue was 49 percent. The probability curve developed by CBTE also indicates that additional Trade Income about $100 million would be zero on average (Ex. 16-5, slides 12 and 13; T8: 1833).

In order to establish a base that would create a 70 percent confidence level of generating a positive income, CBTE concluded that $35 million (one-half of one standard deviation of the income variability) in additional income was needed for the generator. In CBTE's view, this could be created by:

- reducing the Heritage Contract supply obligation (quantity) by 0.5 percent (revised from the original 1 percent) per year;
- increasing the Heritage Contract price by three percent;
- increasing the before-tax return on equity on the Heritage assets by 3.5 percent; or
- reducing the proxy facility charge so that the generator retains a larger share of Trade Income (Ex. 16-5, slides 13, 14, 17; T9: 1988, 1994).

CBTE states that any of these methods would allow the generator to recover $35 million more on average than its revenue requirement (T9: 1986). Risks related to changes in tax regimes, water rental fees or other taxes, and inflation would be accounted for in the $35 million premium (T10: 2093-2095). CBTE's proposal structures the contract so that it is "front-end loaded" such that there is an overpayment of the revenue requirements in the initial years and an underpayment in the final years. CBTE states that the front-end loading reduces the probability of "...a major financial calamity for the generator developing because of a series of bad years..." (T10: 2112).

CBTE also states that its later analysis demonstrates that the level of risk is lower than might be expected for a predominantly hydroelectric system, and that the lower level of risk results from the thermal capabilities available to BC Hydro (Ex. 16-5, slide 19). CBTE notes that this makes the BC Hydro risk profile quite different from the Quebec model because the higher proportion of thermal generation in the BC Hydro system (approximately 10 percent for BC Hydro, versus approximately five percent in Quebec) reduces the risk significantly (T8: 1841; T9: 1865).

CBTE agreed during the hearing that its model of a Fixed Price/Fixed Quantity contract did not incorporate the risk that operating and maintenance costs or generation business sustaining costs could be higher than forecast. However, CBTE did not consider that the exclusion of these risks would affect the overall risk profile of the generator under a Fixed Price/Fixed Quantity contract (T9: 2035, 2038). CBTE subsequently provided a sensitivity analysis of changes in various items including operating and maintenance costs, business sustaining costs, and return on equity. Its analysis indicates that the effect of a combined change in water rental fees, operating and maintenance costs, business sustaining costs, and depreciation and amortization was a change in the risk premium of $2 million to $3 million depending on the assumptions on variation (Ex. 24-3, p. 20).

CBTE states that it would be helpful if the Commission Panel determined that the Heritage Contract should be a Fixed Price/Fixed Quantity contract and, if it is concerned about the reliability of the supporting numbers, the precise price and quantity could be determined at BC Hydro's first revenue requirements proceeding (T9: 1873-74). CBTE acknowledges that the price to be included in such a contract would benefit from further development, especially by BC Hydro (T10: 2129-2130). CBTE also proposes that contract re-openers or force majeure provisions could be used to adjust the price or quantity during the term of the contract in the event of exceptional circumstances.

As a proxy for trade revenue CBTE proposes a contribution of $100 million by BC Hydro Generation to BC Hydro Distribution, which CBTE considers a form of "facility rent", rather than a sharing of the trade revenue. CBTE bases the amount of $100 million on BC Hydro's forecast of Powerex's revenues, which BC Hydro estimates as between $75 to $125 million (Ex. 8, p. 29). CBTE indicates that such a fixed contribution should eliminate the need for regulation of BC Hydro Generation and Powerex. CBTE supports its position against any regulatory oversight of the trading activities of Powerex by reference to the complexities involved in monitoring forecast, real time and after-the-fact trades, and the tracking of the numerous trading functions on a daily basis (CBTE Argument, p. 22,23). CBTE submits that Commission oversight over the Generation line-of-business should be limited to ensuring that the Heritage Resources are properly maintained.

Average Pricing Inefficiencies

Average pricing inefficiency relates to the situation where BC Hydro Generation averages the costs of managing the resources and presents a fixed average price to the BC Hydro Distribution line of business (T10: 2170). Specifically, when the fixed price is higher than the market price, the take-or-pay provision in the Fixed Price/Fixed Quantity model may force BC Hydro Distribution to accept the heritage supply rather than procure the less costly supply.

CBTE submits that any inefficiencies inherent in the Fixed Price/Fixed Quantity model would be minor, and could be offset by what they considered to be efficiencies embedded in their model compared to BC Hydro's Revenue Requirements model. CBTE states that the risk of average pricing inefficiencies would normally occur only when Burrard Thermal has to be operated to satisfy the Heritage obligation, and with the proliferation of efficient thermal units in the marketplace, less costly IPP purchases would, in most situations, displace the operation of Burrard Thermal.

CBTE agrees that there is greater potential for inefficiencies under the Fixed Price/Fixed Quantity model than under the Revenue Requirements model (T10: 2181). However it argues that the streamlining of operations under their model would make efficiency gains possible, since the generator would have a stronger focus on managing the generation resources, which can lead to additional optimization to enhance trade income. CBTE concludes that in terms of efficiency, the difference between the two models should be considered insignificant.

2.6 Responses to CBT Energy Proposal

BC Hydro submits that the additional cost of a Fixed Price/Fixed Quantity contract compared to the Revenue Requirements model, based on the same percentage supply obligation (of total heritage supply) as in the Hydro Quebec contract, would be approximately $163 million annually, significantly higher than the risk premium estimated by CBTE (Ex. 9, Response to BCUC IR No. 1-20.3). BC Hydro states that analysis of the risk profiles of BC Hydro Generation and BC Hydro Distribution would require consideration of their size, customer profile, supply obligations and supply alternatives. BC Hydro cites various risk factors, such as market prices for electricity and natural gas being higher than forecast, lower than forecast water inflow conditions, unanticipated generation outages, and cost increases outside of BC Hydro's control. It states that quantifying and monetizing such risks would be an inherently subjective exercise leading to an uncertain result. While BC Hydro acknowledges that these risks could be mitigated by generous "re-opener" clauses, doing so would, in the extreme, lead to a result no different from the BC Hydro proposal (Ex. 9-2, Response to BCUC IR No. 2-110.2).

BC Hydro argues that the CBTE model does not account for all of the relevant risks including the following:

- operations and maintenance expenses and business sustaining expenses being higher than forecast;
- extended generation outages;
- operating constraints being imposed on the generator (T9: 2030-2037; Ex 25, pp 3-4); and
- BC Hydro's Burrard Thermal Plant being decommissioned (Ex. 1, p. 43; T9: 2048-2052; T10: 2085-2086).

BC Hydro further argues that CBTE's model was not transparent enough to assess whether or not CBTE's treatment of the asymmetry of risk regarding trade revenues and water conditions was adequate (BC Hydro Final Argument, p. 20). CBTE's evidence is that, even though the price data CBTE used to derive its forecast of electricity prices excludes 2000-2001 price data related to the California crisis, the full amount of the volatility is factored in (T9: 1983). BC Hydro disputes the exclusion of that data and the validity of the resulting analysis. BC Hydro further argues that CBTE's assessment of the default risk by the generator is misleading, noting that the cumulative probability of bankruptcy is much higher than appeared in the CBTE evidence. BC Hydro estimates the cumulative probability of a $400 million default would be between ten and fifteen percent by 2015 (Ex. 16-5, slide 22; BC Hydro Final Argument, p. 20).

The JIESC does not support the Fixed Price / Fixed Quantity approach, and rejects CBTE's argument that it is more consistent with the Energy Plan than BC Hydro's proposal. The JIESC identifies a myriad of events and situations that can adversely impact a Fixed Price/Fixed Quantity Heritage Contract including: returns to either party being inadequate to defray costs; inappropriate forecasting of heritage electricity production levels and associated costs over a ten-year period; lack of firmness of the Heritage Reference Price developed by BC Hydro and used by CBTE in its analysis; the appropriateness of any risk premium developed by CBTE; and inadequate accounting for unforeseen operating and business risks. The JIESC argues that CBTE's estimate of $35 million, as an appropriate risk premium, should be met with "significant skepticism". The JIESC considers the exercise undertaken by CBTE to be a very difficult one requiring forecasts of a substantial number of variables over a 10-year period. The JIESC considers CBTE's model and methodology to be vague and untested (JIESC Final Argument, pp. 8-9). The JIESC further submitted that: "there is no evidence that either BC Hydro or the Provincial Government is prepared to accept the risk inherent in a Fixed Price / Fixed Quantity model in return for an additional $35 million of return on equity, or any other amount" (JIESC Final Argument, pp. 8-9). Accordingly, the JIESC recommends that the Fixed Price/Fixed Quantity model be rejected.

The IPPBC also does not support the Fixed Price/Fixed Quantity proposal, and believes that it is neither feasible nor practical. The IPPBC submits that, as proposed by CBTE, the Fixed Quantity/Fixed Price proposal contains the potential for many contract re-openers, which would in effect "…appear to be the same idea as flow-through provisions in electricity purchase contracts" (IPPBC Final Argument, Section 3). The IPPBC further states that even though risk premiums are associated with the CBTE proposal, such premiums do not guarantee fulfillment of obligation.

Nor does the BCOAPO support the Fixed Price/Fixed Quantity approach, which it believes is not in the best interest of ratepayers (BCOAPO Final Argument, p. 5). The BCAOPO submits that there is no guarantee that BC Hydro's ratepayers would in fact be protected from risk under a Fixed Price/Fixed Quantity model, even after paying the risk premium. The BCOAPO also rejects CBTE's argument that the Terms of Reference did not contemplate that BC Hydro Generation would be closely regulated by the Commission.

The CEC does not support the Fixed Price /Fixed Quantity model and submits that, while it appears to give customers certainty with respect to the price and quantity of heritage electricity, "...it in fact provides no real certainty and in the end will cost the customers more." (CEC Final Argument, p. 31).

CBTE argues that it did consider the risks BC Hydro has raised. CBTE states that risks related to water use planning changes would have to be addressed through contract re-openers, but that such re-openers would have to be considered in determining the appropriate risk premium. CBTE further argues that, in considering the risk of operating and maintenance costs being higher than forecast, CBTE relied on BC Hydro's evidence that such cost components were relatively stable. Moreover, CBTE notes that it provided sensitivity analysis of changes in such items and argues that the variability of those cost items would not materially affect the risk premium (CBTE Final Argument, Appendix A, pp. 3-4).

CBTE considers the risk premiums and bankruptcy potential raised by BC Hydro to be unsubstantiated scare tactics to dismiss the Fixed Price/Fixed Quantity model. CBTE further argues that although BC Hydro does say that the risk can be quantified, it says that experts would be required to quantify the risk premium, but that BC Hydro did not attempt to retain such experts (CBTE Final Argument, pp. 9-10).

CBTE reiterates its position that the risk premium is lower than it first estimated because only a small portion of the Heritage Contract energy is exposed to market price variability, and secondly, the generator can effectively hedge its costs against market prices through the use of Burrard Thermal (CBTE Final Argument, p. 19).

2.7 Ancillary Services Requirements to BC Transmission Corporation

Most of the ancillary services requirements of BCTC are generation related (see Section 2.1) and therefore will normally be sourced from BC Hydro Generation. Any ancillary services supplied to BCTC from BC Hydro (BC Hydro has a responsibility to continue to offer WTS service [T2: 266]), will be recovered as part of the BC Hydro revenue requirement. Ancillary services required by BC Hydro will be self-supplied pursuant to a BCTC tariff. Transactions pursuant to the Transfer Pricing Agreement are also provided by the Heritage Resources. Self-supply and Transfer Pricing Agreement transactions may reduce the availability of ancillary services to BCTC.

2.8 Legislative Changes to Implement the Heritage Contract

Paragraph 1 in the Terms of Reference asks for the Commission's Recommendations on what changes, if any, should be made to legislation, regulations, special directions or special directives affecting BC Hydro or the Commission or both in order to implement the Energy Plan and the Heritage Contract.

BC Hydro proposes that the Heritage Contract could be legally implemented by appropriate amendments to SD4 to BC Hydro, and SD8 to the Commission, and provides the Commission with the amended versions as appendices to the Utility's Final Argument. The amended Special Directive and Special Direction (which include further revisions by the Commission Panel) are attached to this Report as Appendices C and D, respectively.

BCOAPO agrees with BC Hydro that changes to SD4 and SD8 would suffice to implement the Heritage Contract, but that such changes would not likely be adequate to implement the Fixed Price/Fixed Quantity proposal.

CBTE does not propose any specific form of legislation, but emphasizes that: "...any fixed price/ fixed quantity contract should be implemented through legislation...." CBTE further adds that the legislation could identify the specifics of the Heritage Contract such as energy entitlement, parties to the contract, contract start date and end date, and that renewal provisions and prices should be set by the Commission (CBTE Argument, p. 24).

The CEC proposes that "...the Government of BC enact legislation to establish an independent corporate trust with a Board of Directors appointed by the Government from the ratepayer constituencies...." (CEC Final Argument, p. 6). The CEC submits that this corporate trust would be the legal entity to hold the Heritage Contract in trust for the Heritage Beneficiaries, and would be a party to the Heritage Contract for the supply of the heritage electricity. The CEC further states that it does not believe that mere changes to SD4 and SD8 would be adequate to protect the rights of the ratepayers.

BC Hydro has emphatically rejected the CEC proposal, citing CEC's failure to lead evidence in support of its proposal at the Inquiry, and stating that the proposal's lack of clarity and specificity prevented a thorough evaluation of its feasibility (BC Hydro Reply Argument, p. 8).

The JIESC proposes that the Heritage Contract be enshrined in legislation.

2.9 Contract Term and Renewal

Participants' views on an appropriate contract renewal provision are linked to their views on an appropriate contract term. BC Hydro proposes a four-year notice period prior to the expiry of the Heritage Contract. The JIESC submits that: "the longer customers believe that they will continue to receive the benefits of the low imbedded cost Heritage assets the more attractive British Columbia will be as a place to do business and invest" (JIESC Final Argument, p. 9). The JIESC therefore recommends that the Heritage Contract be renewed on a rolling 20-year basis. The CEC proposes a ten-year term with provisions for automatic annual renewal on a ten-year rolling basis. The IMEU suggested a fifty-year Heritage Contract with formal review for extension at that time.

Most participants prefer a combination of contract duration and renewal provision that provides the most certainty for the longest period of time.

2.10 Commission Panel Views

Heritage Contract

The Commission Panel appreciates that BC Hydro and CBTE provided competing Heritage Contract structures for its review. The Commission Panel also appreciates the views and analysis made by the other participants in the process. Both BC Hydro and CBTE argue that their respective proposals are more consistent with the Terms of Reference and the Energy Plan.

BC Hydro argues that the purpose of the Heritage Contract is to serve two key objectives from the Energy Plan: low electricity rates and secure reliable supply. BC Hydro further argues that other objectives are to be served by the Energy Plan but not by the Heritage Contract (BC Hydro Final Argument, p. 2).

CBTE argues that "locking in" the benefits of the Heritage Resources is fundamental to the Energy Plan, and that the Energy Plan must be considered in the context of the work of the Energy Policy Task Force appointed by the Government in 2001 and early 2002. In the view of CBTE, "...the thrust of the task force review process resulting in the Energy Plan was the need to make fundamental changes to the electricity industry in British Columbia. Status quo was not an option" (CBTE Final Argument, pp. 3-4). CBTE also emphasizes the discussion in the Energy Plan of Policy Action #1, which states that the Heritage Contract is similar to arrangements that have been adopted in Quebec (CBTE Final Argument, pp. 5-6).

CBTE's most significant criticism of the Revenue Requirements model is that it does not effect the changes that it argues are contemplated in the Energy Plan. It states that the Revenue Requirements model is an acceptance of the status quo. If the Government intends to implement significant changes to the structure of the electricity sector by means of the Heritage Contract, the Fixed Price/Fixed Quantity contract may be preferred.

The Commission Panel agrees with the interpretation of BC Hydro that the Heritage Contract is, above all, intended to secure the dependable low-cost electricity from the Heritage Resources for BC Hydro's consumers. In reaching its conclusions, the Commission Panel notes repeated references in the recital clauses of the Terms of Reference to the regulation of BC Hydro's rates in order to ensure adequate supplies of dependable, low-cost electricity provided at low and stable rates to BC Hydro's customers.

In the Commission Panel's view, the key issue is which contract structure provides the most assurance that these objectives will be achieved. The Commission Panel is not persuaded that there must be change to the traditional form of regulation unless an alternative can be shown to provide greater benefits to ratepayers. The Commission Panel also concludes that either form of contract "locks in" the benefits to ratepayers, but with fundamentally different distributions of risks.

The Revenue Requirements model essentially follows past regulatory practice with respect to the allocation of risk. In line with the regulatory compact, periodic adjustments to rates award Utility shareholders a return commensurate with investments of comparable risk. The Fixed Price/Fixed Quantity model with its guaranteed contract shifts more risk to the Utility shareholder and makes provision for added compensation.

The Commission Panel concludes that although the Fixed Price/Fixed Quantity model may result in average pricing inefficiencies, such inefficiencies may reasonably be expected to be offset by efficiencies gained from a more focused mandate of BC Hydro Distribution and BC Hydro Generation. The Commission Panel concludes that the selection of the Heritage Contract model should not turn on considerations of efficiency or inefficiency that might arise from such selection. Therefore the Commission Panel does not consider this further.

The Commission Panel is cognizant of the number of uncertainties in the changing North American energy market that will have an impact on BC during the initial 10-year term of the Heritage Contract. The impossibility of addressing these in specific terms within a Fixed Price/Fixed Quantity contract implies the need for a significant risk premium. It is not clear that the Commission could utilize the CBTE methodology to formulate a risk premium that would place BC Hydro in conformity with other regulated utilities. It is also unlikely that ratepayers would willingly accept the increased cost that would result from such a risk premium.

The Revenue Requirements model proposed by BC Hydro offers flexibility by maintaining regulatory oversight by the BCUC. The degree of oversight could be relaxed and replaced by appropriate incentive mechanisms as experience is gained. Moreover, Policy Action #5 of the Energy Plan does not contemplate the deregulation of a significant portion of BC Hydro, as is proposed by CBTE.

During the Inquiry, BC Hydro's proposal for a Heritage Contract had the support of almost all participants with the exception of CBTE. BC Hydro states in Reply Argument (p. 1):

> The most significant observation to be taken from the intervener Final Arguments is the near-unanimous support of BC Hydro's revenue requirements model for the Heritage Contract.… BC Hydro respectfully submits that the Commission has an obligation to advise government of this very high level of support for the revenue requirement model and ought to further advise government that in this proceeding there was no viable alternative approach presented, let alone an alternative that should be imposed on customers against their will.

In the Commission Panel's view, the objectives outlined earlier in this section are better served through the Revenue Requirements model. The Commission Panel also affords weight to the preference of BC Hydro's customers. Accordingly, the Commission Panel concludes that the Province should adopt a Heritage Contract structured upon the Revenue Requirements model proposed by BC Hydro. In response to those parties who wished the greatest possible certainty with respect to the term of the Heritage Contract, the Commission Panel concludes that the Heritage Contract should have a ten-year term and provision for automatic annual renewal. Termination may occur at the end of the ten-year term by a Government policy direction.

The Commission Panel also accepts the arguments of those parties who argued that generation projects that derived substantial benefit from, or were reliant on, existing Heritage Resources should be considered part of the Heritage Resources. In the view of the Commission Panel, SD8 should be amended to allow for Commission review to determine whether such projects should be included as Heritage Resources in the Heritage Contract. The amendments to SD8 should include a provision that the Commission may revise the amount of heritage energy or the HPO should there be a significant change in circumstances affecting the capability of the Heritage Resources or the costs of generation. Such a change might be the result of a capital addition or capital extension.

Finally, some parties expressed concerns about the definition of equity components established by SD8. There is sufficient customer concern that the Government should consider reviewing SD8 and SD4 regarding the definition of equity and deferred credits. If, as a result of that review, it decides to revise the definition of equity and deferred credits in SD8, then issuing such revisions prior to January 31, 2004 would be desirable so as to incorporate the revisions into BC Hydro's anticipated Revenue Requirements application.

Trade Income

The Commission is to make specific recommendations with respect to the allocation of Trade Income pursuant to Term of Reference subparagraph 3(h)(ii). Trade Income is defined as the audited net income of Powerex which is based on generally accepted accounting principles. The audited net income of Powerex is determined, in large part, by the pricing of power transactions between Powerex and BC Hydro. The pricing of those power transactions is determined pursuant to the terms of the Transfer Pricing Agreement.

The Revenue Requirements model as proposed by BC Hydro introduces significant changes with respect to Trade Income. As stated by BC Hydro's counsel, the "resolution of that [Trade Income] … is the biggest change that the regulatory model introduces and it's far from trivial change. I think it's a really significant change" (T11: 2253). The Commission Panel agrees. In accepting BC Hydro's proposed Heritage Contract and treatment of

Trade Income, the Commission Panel has placed considerable weight on the support of the customers and the clarity that the BC Hydro model provides on the issue of Trade Income.

The only alternative to BC Hydro's Trade Income proposal was the CBTE Trade Income proposal. However, the CBTE Trade Income proposal was dependent on the CBTE Heritage Contract model and is therefore, not helpful in the context of the BC Hydro Heritage Contract model.

The share of trade revenue that will accrue to the Government under the BC Hydro proposal is that amount that exceeds $200 million in any given year. No sharing is proposed below $200 million. BC Hydro's evidence is that only under unusually high water years will trade revenue exceed $200 million.

Under generally accepted regulatory practices, all the benefits derived from regulated assets are allocated to customers. Trade Income is a benefit derived from regulated assets, but is determined pursuant to the terms of the Transfer Pricing Agreement that establishes the price of power for sale and purchase transactions between BC Hydro and Powerex. Provided that the Revenue Requirements model is accepted by the Government, then in BC Hydro's opinion the Transfer Pricing Agreement: 1) should not be amended without regulatory approval; 2) is an "energy supply agreement" as defined in section 71; and 3) should not be the subject of legislation, regulations or special directions.

Within the range $0 to $200 million the net income of Powerex is allocated to customers. As a result, the risk for trades after Powerex pays BC Hydro the transfer price results from the activities of Powerex but is borne by the customers within the specified range for Trade Income. Therefore, under the BC Hydro proposal the benefits derived from regulated assets and the risks associated with the trading activities of Powerex are either allocated to or borne by the customers.

BC Hydro's Heritage Contract and its treatment of Trade Income can be severed, that is, changes to its treatment of Trade Income can easily be accommodated within BC Hydro's Heritage Contract. Consequently, the Government could replace the proposed allocation with another allocation as it is an issue independent of the Heritage Contract. A change to the allocation of Trade Income could be effected by a change to the definition of Trade Income in SD8 (attached as Appendix D). The Commission Panel's Recommendation #18 would then not be accepted by the Government, but would then need to be amended to incorporate the sharing mechanism.

Trade Income and Regulatory Oversight

The appropriate regulatory role of the Commission Panel depends on the elements of sharing and incentive mechanisms associated with Powerex's trade activity.

Trade Income with No Sharing between Zero and $200 Million

BC Hydro states that it believes that "... the Commission should continue to ensure that it is informed regarding Powerex's trading activity by requiring the continued production of Export Trade Reports, but should not become directly involved in overseeing Powerex's activities" (BC Hydro Final Argument, p. 13). The Commission Panel is not persuaded that remaining informed through reports such as the Export Trade Reports is a role of regulation, nor that effective regulation is possible through such reports.

Storage from the Heritage Resources facilitates the trade activities of Powerex that are Transfer Pricing Agreement transactions. The Transfer Pricing Agreement ensures that transactions between BC Hydro and Powerex are at a transfer price based on a market index. Therefore, the benefits of storage accrue to customers through the operation of the trade account, as defined by the Transfer Pricing Agreement, and Trade Income, as defined by SD8. If BC Hydro's proposal is adopted, that is, no sharing of Trade Income between zero dollars and $200 million, the Commission Panel is satisfied that the alignment of interests of BC Hydro Distribution, BC Hydro Generation, and Powerex would render regulatory oversight of Powerex unnecessary.

Trade Income with Sharing between Zero and $200 Million

BC Hydro submits that, if there is sharing of Trade Income under the $200 million cap, a misalignment of incentives for BC Hydro Distribution will result when making a choice between increasing Trade Income or increasing IPP purchases (T4: 950). The Commission Panel is not persuaded that such a sharing would have a significant impact on the choice of BC Hydro Distribution between increasing Trade Income or increasing IPP purchases. If Trade Income is defined as the net income of Powerex, all transactions of Powerex will be the subject of sharing. Therefore the Commission Panel believes that if there is to be sharing, the Commission should then determine the appropriate regulatory framework.

Trade Income with No Sharing, together with an Incentive Mechanism for Powerex

The Commission Panel accepts BC Hydro's proposal with respect to Trade Income, characterized here as "Trade Income with No Sharing", together with an incentive mechanism for Powerex.

More, or different, regulatory oversight may be required if an incentive mechanism is implemented. Although a Powerex witness said that no consideration had been given to an incentive mechanism yet (T4: 744) the Commission Panel believes that such an incentive mechanism should be considered in the future, after BC Hydro's revenue requirement proceeding. The appropriate regulatory oversight will depend on the incentive mechanism and, therefore, the Commission Panel believes that regulatory oversight should be defined together with approval of the incentive mechanism.

3 STEPPED RATES

3.1 Introduction

The Energy Plan adopts stepped rates as one means to support the Plan's objectives to assure low electricity rates, provide secure reliable supply, encourage private sector investment opportunities and ensure environmental responsibility.

Policy Action #14 of the Energy Plan specifies that under new rate structures large electricity consumers will be able to choose a supplier other than the local distributor. This policy action contemplates that new stepped pricing will provide an incentive for large industrial or transmission rate customers to purchase from IPPs, or to self-generate, when they can do so less expensively than the Utility's cost of new supply. Policy Action #21 stipulates that new rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency. Taken together, Policy Actions #14 and #21 refer to stepped rates as a pricing structure intended to spur purchases from IPPs or investments in energy efficiency. However, these policy actions, and the stepped rates they contemplate, are anticipated to provide benefits that broadly support all the overarching objectives of the Energy Plan.

Paragraph 4 of the Terms of Reference directs the Commission to make specific recommendations relating to any changes it believes are desirable in the rates of transmission voltage customers to accomplish the objectives set out in the Energy Plan. Subparagraph 4(b) directs the Commission to make specific recommendations on the detailed provisions of new stepped rate schedules as described in the Energy Plan, including load aggregation by a customer with facilities at more than one location.

Policy Action #21 specifies a principle that to keep rates low overall, the stepped rate structure will be revenue-neutral. The Energy Plan defines a revenue-neutral two-step electricity rate as charging less for an initial block of energy consumed and more for a second block, relative to the prevailing flat rate, while at total existing consumption (the sum of the first and second block initially), the total cost to the consumer and the total revenue to the distribution company offering the rate remains unchanged (Ex. 1, p. 33).

3.2 BC Hydro Stepped Rate Proposal

Guiding Principles

BC Hydro's April 30 Stepped Rate Proposal (Ex. 8-1) defined three principles for a stepped rate: it should be a mandatory tariff; it should be revenue or bill neutral at historical consumption levels; and it should be margin-neutral at all consumption levels. In BC Hydro's view, failure to adhere to these principles will cause cost-shifting between customers.

By proposing that the stepped rate be a mandatory tariff, BC Hydro is applying the principle that customer decisions at the margin should respond to the cost of new supply, rather than to an existing embedded cost rate or a blended rate of old and new costs. BC Hydro identifies that the continuation of Rate Schedule 1821 ("RS 1821") would result in an inability to achieve Energy Plan Policy Actions #14 and #21. BC Hydro has interpreted the Energy Plan and the Terms of Reference for the Inquiry to imply that the stepped rate should apply to RS 1821 and all related schedules.

The principle of revenue or bill neutrality at historic consumption levels reflects a requirement that a customer's bill should remain unchanged after the implementation of a stepped rate if the customer does not change its consumption relative to past levels.

BC Hydro proposes that the stepped rate should be margin neutral at all consumption levels. Margin in this context is defined as revenue less cost, adjusted for risk. BC Hydro's principle of margin neutrality is intended to ensure that bill credits granted to customers for their energy savings do not exceed BC Hydro's risk-adjusted value of the saved energy, and that the incremental costs and risks of acquiring new supply are recovered in bills sent for additional growth. That is, BC Hydro requires margin-neutrality to ensure that a stepped rate design does not shift costs to non-participating customers. According to BC Hydro:

> A rate design is margin-neutral if BC Hydro's net margin from all of its activities, including sales of energy to retail customers and wholesale market trading, does not change incrementally from implementation of the rate design. (Ex. 8-1, p. 21)

These three principles are the basis of BC Hydro's proposals for stepped rate design.

BC Hydro also notes that:

> Rates that are margin neutral must also make use of access rules to prevent margin loss due to rate arbitrage. The rate arbitrage problem is introduced by allowing customers to freely switch

> among different stepped rate contracts and alternative avenues for access to the wholesale market. If customers are allowed to continually switch back and forth between different rate designs, rate schedules or suppliers, depending on which one provides immediate gain, the resulting rate arbitrage has the potential to shift costs to non-participants. (Ex. 8-1, p. 9)

Stepped Rate Parameters

Exhibit 8-1 offered a general framework and principles for initiating a discussion of stepped rates for transmission voltage customers. This proposal did not include a specific rate design because BC Hydro did not fully understand customer preferences for a particular design and the specific options that it should include.

Exhibit 8-1 included a detailed Stepped Rate Design Report by Energy and Environmental Economics, Inc. ("E3") that discussed detailed stepped rate design options, including an assessment of the objectives and risks associated with the various options. In particular, the report compared a simple two-tiered stepped rate design with designs that included a shopping credit mechanism wherein customers are credited for reduced energy consumption based on the cost of new supply.

A simple two-tiered rate design requires decisions about the following design parameters: a Tier 1 rate, a Tier 2 rate, and a percentage of Customer Baseline Load ("CBL") to be billed at each rate (the Tier 1/Tier 2 Split). A revenue-neutral two-tiered rate necessarily requires that any two of these three parameters be set directly, with the remaining parameter derived as a function of the other two to ensure that the revenue collected under the stepped rate equals the revenue that would have been collected under a single rate (like RS 1821).

A shopping credit mechanism paired with a two-tiered stepped rate provides a bill offset for reduced Tier 2 energy consumption based on the cost of new supply. Its purpose is to afford greater flexibility to setting the stepped rate parameters without diminishing the incentives for conservation and energy efficiency that the overall rate design is intended to provide.

BC Hydro initially proposed that the stepped rate include a shopping credit mechanism. BC Hydro sees merit in the shopping credit mechanism for a number of reasons. It believes that the mechanism would allow it to offer direct access under a retail tariff without completely unbundling retail rates, it lends itself to phased-in and flexible implementation, and it would allow it to more clearly identify and mitigate any associated risks. However, BC Hydro learned through customer consultations that there is little support for the shopping credit mechanism. BC Hydro therefore concluded in its further proposal regarding stepped rates (Ex. 8-2) that a stepped rate with a shopping credit would not be successful if customer opposition to the shopping credit inhibited the price signal the design was intended to send. On that basis, BC Hydro abandoned its shopping credit approach, and proposed instead a simple two-tiered rate that it believed adhered to its guiding principles for stepped rate design.

Two-tiered Stepped Rate Proposal and Argument

BC Hydro submits that all parties agreed that a basic stepped rate design will include a Tier 1 rate, a Tier 2 rate and an amount of energy, as a percentage of CBL, billed at each of the two rates (the Tier 1/Tier 2 Split). BC Hydro maintains that so long as the revenue neutrality principle is maintained, the stepped rate that it proposes will be cost based and customers need have no fear that their rates, taken as whole, will vary significantly from cost.

Tier 2 Rate

BC Hydro believes that the two most important parameters about which policy choices should be made are the determination of the Tier 2 rate and the percentage of CBL energy billed at the Tier 1 and Tier 2 rates (Ex. 8-2, p. 4). Of these two parameters, BC Hydro believes that the choice of the methodology for determining a Tier 2 rate is paramount. BC Hydro notes that a Tier 2 rate based on the cost of new supply, as called for by the Energy Plan, will likely be considerably higher than the cost of its existing resources. For this reason, it is concerned that a poorly designed Tier 2 rate could lead to customer decisions that result in cost-shifting among and between customers, and between customers and the shareholder. This concern is reflected in BC Hydro's principle that the stepped rate be margin-neutral.

BC Hydro proposes that the Tier 2 rate be set at BC Hydro's opportunity cost[1], which it believes reflects its true cost of new supply. BC Hydro notes that its opportunity cost is a function of the market price of energy imports or exports relative to its current value of energy. BC Hydro states that to promote a level playing field between supply from BC Hydro, IPPs, customer-based generation ("CBG") and conservation, the Tier 2 rate must be no lower than its opportunity cost. BC Hydro believes that a Tier 2 rate lower than its opportunity cost may not provide a sufficient incentive for customers to change their consumption patterns, resulting in missed savings opportunities. BC Hydro also believes that a Tier 2 rate must be no higher than its opportunity cost in order to avoid providing an artificial incentive for customers to reduce purchases from BC Hydro, leading to lost margin,

[1] *Opportunity cost* is an economic term that embodies the concept that the true cost of any action can be measured by the value of the best alternative that is foregone when the action is taken.

and ultimately higher rates (Ex. 8-2, Ex. 38).

BC Hydro interprets "new supply" to mean future supply; that is, supply that has not yet been obtained. BC Hydro proposes that an appropriate proxy of its opportunity cost of future supply is the expected cost of purchasing electric energy for a one-year period. On this basis, BC Hydro proposes that the Tier 2 rate be based on the forward market price of a one-year contract for Mid-Columbia ("Mid-C") delivery. BC Hydro suggests that such a price can be obtained through one-year Mid-C product quotes from brokers or energy exchanges, and approved through a Commission process. BC Hydro views the Mid-C market as competitive and robust, in terms of both the number of transactions and the number of participants. BC Hydro believes that a one-year forward Mid-C price provides an objective, verifiable reference point for ratemaking purposes.

BC Hydro notes that it does not expect its Tier 2 rate proposal to be perfectly margin neutral, given the complexity, administrative cost and volatility that such a Mid-C based rate would entail. However, BC Hydro believes it is an acceptable compromise between avoiding cost shifting and providing a stable price for investment.

BC Hydro prefers, at least initially, a Tier 2 price that is set for one year. BC Hydro believes that it would be risky to guarantee a Tier 2 rate for longer than one year when it is uncertain what its revenue requirement will be for the stepped rate class. It is also concerned that locking in the rate for more than one year increases the risk that the Tier 2 rate will turn out to be an inappropriate reflection of BC Hydro's cost of supply.

BC Hydro submits that all parties except the JIESC accept that it is appropriate to offer a one-year price for customers who are only prepared to commit to wholly or partially leaving BC Hydro service for a one-year period. BC Hydro proposes that, after BC Hydro and stakeholders have become more experienced with the stepped rate, Tier 2 options that include a longer-term price and time-of-use pricing could be considered. However, BC Hydro would require that the term upon which such a Tier 2 price is determined should correspond to the commitment on the part of the customer. BC Hydro would require a commitment to price, term, quantity, and shape, as well as a proper imbalance charge. In general, BC Hydro believes that any Tier 2 rate would need to reflect its opportunity cost over the corresponding term in order to mitigate arbitrage risk.

Tier 1/Tier 2 Split

BC Hydro believes that of the two remaining stepped rate parameters, the Tier 1 rate and the Tier 1/Tier 2 Split, it is most prudent to set the Tier 1/Tier 2 Split. BC Hydro suggests that this approach is more supportive of the

Energy Plan objectives to encourage conservation and investments in energy efficiency or alternative supply.

BC Hydro proposes that Tier 1 consumption should initially be set at 90 percent of the CBL of industrial customers, with Tier 2 consumption set at 10 percent of CBL. BC Hydro believes that this Tier 1/Tier 2 Split "strikes the correct balance between volume risk for BC Hydro and customer opportunity" (Ex. 8-2, p. 7). BC Hydro notes that a very small percentage of energy available at the Tier 2 rate (for example, 2 percent of CBL) would not provide a significant increase in the incentive for customers to invest in energy efficiency or alternative supply, as compared to the existing 1821 rate. Conversely, BC Hydro contends that significantly increasing the amount of Tier 2 energy beyond 10 percent of CBL at this time would result in an unacceptable risk of cost-shifting as the amount of customer load reductions increase.

Tier 1 Rate

BC Hydro proposes that the Tier 1 rate should be derived as a function of the Tier 2 rate and the Tier 1/Tier 2 Split to ensure revenue and bill-neutrality at the CBL of industrial customers.

BC Hydro contends that a stepped rate design that otherwise set the Tier 1 rate and derived the Tier 1/Tier 2 Split is impractical and could increase the risk of cost-shifting. BC Hydro argues that it would be difficult to administer a rate design in which the Tier 1/Tier 2 Split floats with changes to revenue requirements. Moreover, BC Hydro expects that customers would prefer the certainty of a fixed volume of their load exposed to market-based pricing, rather than a volume that varies from one year to the next. If the Tier 1/Tier 2 Split floats, customers could find that their Tier 2 volumes could actually increase after making investments to reduce their usage.

BC Hydro is not necessarily opposed to a Tier 1/Tier 2 Split that floats according to its revenue-requirements. BC Hydro could implement a rate with fixed Tier 1 and Tier 2 rates and a floating Tier 1/Tier 2 Split. However, BC Hydro would require that the Tier 1 rate be set to recover all of the fixed costs of the Heritage Resources, costs that BC Hydro incurs to serve the industrial class. BC Hydro rejects the JIESC proposal that the Tier 1 rate be based only on Heritage hydro resources, in part because BC Hydro contends that industrial customers who reduce their Tier 2 load in response to the stepped rate would avoid paying for the fixed costs of heritage thermal resources, resulting in a shift of these costs to other customers. BC Hydro is also concerned that the JIESC's proposal to include these fixed costs in the Tier 2 rate will lead to a Tier 2 rate greater than its opportunity costs, with the consequent arbitrage risks and cost-shifting implications discussed earlier.

BC Hydro proposes that if the Commission accepts a design where the Tier 2 rate is market-based and the Tier 1 rate is based on the cost of the Heritage Resources, the Tier 1 rate should include all of the fixed costs (but not the variable costs) of the heritage thermal resources.

Customer Baseline Load

BC Hydro suggests that most stakeholders agree that CBLs are necessary to implement stepped rates since an estimate of historical consumption is required as a reference point to determine a cut-off between Tier 1 and Tier 2 consumption and to ultimately ensure that the stepped rate design is revenue and bill-neutral at historical consumption levels. BC Hydro also suggests that most stakeholders agree that the CBL methodology under Real-Time Pricing (RS 1848) has been successful and could be applied to stepped rates. Hence, BC Hydro proposes the following (Ex. 8-2, pp. 7-9):

- CBLs should be based on an average of the last three years of consumption for both demand and energy, but that allowances should be made for anomalies in the production cycle of the customer.
- The sum of individual CBLs should be compared to existing total consumption of the RS 1821 customers, and the overall allocation under the CBLs normalized to equal existing total consumption.
- CBLs should be fixed so long as customers consume within a plus or minus 10 percent deadband around CBL. The deadband is intended to provide customers some flexibility to manage normal load variations.
- A review of whether an adjustment to CBL is required would be triggered if a customer's actual consumption fell outside the deadband; that is, less than 90 percent of its CBL or greater than 110 percent of its CBL.
- The Commission would approve CBLs and subsequent adjustments to them, and resolve any associated disputes.

BC Hydro suggests that whether an adjustment to CBL is warranted would depend on whether declines in consumption are related to the objectives of the Energy Plan that the stepped rate is designed to serve, or whether increases in consumption are associated with increases to productive capacity. A reduction to CBL may be required if declines in consumption are not associated with energy efficiency investments or IPP supply, for example. An increase to CBL may be required if production capacity increases at existing facilities, adjustments that BC Hydro asserts would allow new load to be treated equitably with load growth at existing facilities.

BC Hydro proposes that CBLs be reduced to account for any PowerSmart and CBG investments that are coincident with stepped rate implementation, so long as these investments are financially supported by BC Hydro. This would prevent a customer receiving both the benefit of BC Hydro's investment and a commensurate benefit for reduced consumption of Tier 2 energy.

Load Aggregation

BC Hydro has proposed that customers with facilities at more than one location should not be able to aggregate their loads into one combined CBL. One suggested benefit of "load aggregation" is that it could allow customers with multiple locations to justify investments in energy efficiency that would otherwise be uneconomic. BC Hydro contends that incentives under Tier 2 together with PowerSmart and CBG Programs will accommodate any considered investments.

BC Hydro is concerned that customers should not be encouraged to aggregate their CBLs and then achieve significant savings by simply closing down one of their facilities. It contends that this would disadvantage customers with only one facility, and in general not be in the public interest. BC Hydro would have no objection to load aggregation if there were limitations that addressed this concern. BC Hydro accepts that an appropriate limitation, if suitably developed, would be only to allow load aggregation across operating facilities.

Demand Charge

BC Hydro proposes that an industrial customer's demand charge should be based on a fixed CBL for capacity demand, calculated according to the method proposed for a customer's CBL for energy consumption. The demand charge would be fixed so long as a customer's energy consumption remained within a deadband of plus or minus 10 percent. BC Hydro proposes that the demand charge would be adjusted to reflect any changes to a customer's CBL of energy consumption (BC Hydro Final Argument; T6: 1352). BC Hydro recognizes that, if stepped rates were implemented prior to its revenue requirement and rate design proceedings, the demand charge should be set to equal the existing RS 1821 demand charge.

BC Hydro asserts that aggregating demand charges would shift costs to other customers. If a customer's demand charge was based on a single aggregate peak demand, as opposed to the sum of two non-coincident peak demands, BC Hydro contends there would be no consequent short or medium-term benefit to BC Hydro or its other customers.

3.3 Submissions and Arguments of Inquiry Participants

Joint Industry Electricity Steering Committee

The JIESC notes that industrial customers did not ask for stepped rates. However, the JIESC would accept mandatory stepped rates provided they are cost-based, predictable and stable. They would otherwise request that stepped rates not be implemented, but rather that targeted programs be continued.

The JIESC recommends that the stepped rate be cost-based. It believes that this would be most easily accomplished with reference to BC Hydro's Heritage Resources. The JIESC notes that BC Hydro has suggested that there is no link between stepped rates and the Heritage Contract; however, the JIESC believes that stepped rates are the vehicle for delivering the benefits of the Heritage Resources to industrial customers.

The JIESC argues that the amount of energy billed at the Tier 1 rate should be based on a clearly defined portion of the Heritage Resources, preferably, the Heritage hydro resources. The amount of energy billed at the Tier 2 rate should be based on the amount of all other BC Hydro resources, including purchased electricity. The JIESC argues that rates based on cost are seen to be sustainable and not subject to countervail arguments in export markets, and as such will promote investment and economic growth.

The JIESC submits that earlier material provided by BC Hydro suggests that on the basis of the JIESC proposal, the Tier 1 cut-off is in the range of 87 to 90 percent of CBL. The JIESC contends that BC Hydro has arbitrarily chosen a 90/10 split between Tier 1 and Tier 2 and that there is no evidence to suggest that a larger split might expose BC Hydro to undue risk in terms of load loss. The JIESC believes that until the actual quantity of Heritage Resources is verified in a rate design review, it is appropriate to set the Tier 1 cut-off at 90 percent as a proxy. The JIESC submits that its approach results in a price differential sufficient to ensure that appropriate incentives exist to spur efficiency and self-generation investments, or IPP purchases. The JIESC submits that the weighted average of Tier 1 and Tier 2 rates and volumes will equal the weighted average rate for RS 1821 customers. Further, it notes that if its cost-based approach leads to a weighted average rate that differs from RS 1821, then the cost-based rates should be implemented.

The JIESC submits that Tier 2 rates based on the actual cost of all non-hydro BC Hydro resources would in fact be based on a portfolio of resources that includes some market purchases, natural gas generation, CBG and green power generation. These resources, largely gas based, should accurately "reflect" BC Hydro's cost of new supply.

The JIESC opposes BC Hydro's approach to base the Tier 2 rate on a Mid-C one-year forward price. The JIESC contends that this price is not transparent and lacks simplicity, predictability and stability. It believes that the one-year price is a short-term indicator, a price signal that is too volatile and will therefore act more to frustrate than encourage long-term investments in energy efficiency.

The JIESC submits that BC Hydro has not attempted to propose a cost of new supply, as the phrase is used in the Energy Plan; a one-year Mid-C price is quite different than the cost of resources BC Hydro must acquire to serve its customers. The JIESC argues that load growth will not be served by market purchases, but rather through incremental sources, such as the Vancouver Island Generation Project, or through tendered proposals for CBG or green power generation. The JIESC proposes that an estimate of the costs of these resources would clearly reflect the cost of new supply but may be subject to considerable debate between affected parties as to cost and weight.

The JIESC disagrees with BC Hydro's concerns about cost-shifting and BC Hydro's position that net revenue reductions from the industrial customers from stepped rate implementation should be isolated within the industrial class. The JIESC argues that all classes will benefit from conservation and efficiency investments by industrial customers. To reduce demand from BC Hydro, industrial customers will need to purchase from IPPs, construct co-generation facilities or invest in energy efficiency using scarce resources otherwise available for other aspects of business enterprise. And to the extent they can do this, the JIESC argues that BC Hydro can divert this saved power to serve growing residential and commercial demand, resell it, or store it for later use or sale.

The JIESC also made comments on BC Hydro's concern that including the fixed costs of non-hydro Heritage Resources in the Tier 2 rate could increase the risk of arbitrage and consequent cost-shifting. The JIESC argues that BC Hydro ignores the long-term prospect that the cost of BC Hydro's existing generation assets should be equal to, or less than, the cost of replacement generation. BC Hydro focuses instead on an expectation that the JIESC's proposed Tier 2 price may exceed BC Hydro's opportunity cost for limited periods of time. The JIESC argues that the solution to arbitrage risk is to implement appropriate notice periods rather than setting a Tier 2 rate equal to a short-term market price. The JIESC points out that neither it nor other parties have proposed that industrial customers should be given market access under which they could choose on a day-to-day basis to take the lower of Tier 2 or market prices. The JIESC asserts that BC Hydro's assessment of the potential cost of arbitrage risk is improper because it was based on such a possibility.

The JIESC proposes that individual customers negotiate their CBLs with BC Hydro and be supervised by the Commission. It agrees that CBLs should be based on past experience adjusted for anomalies. The JIESC contends that a methodology consistent with that utilized with Real-Time Pricing (RS 1848) can work. The

JIESC also agrees that CBLs may be adjusted to recognize increases or decreases in production that exceed a deadband of plus or minus 10 percent.

The JIESC proposes that PowerSmart and CBG Programs should continue in conjunction with stepped rate implementation. The former would support larger targeted initiatives, with stepped rates providing incentives for undefined and smaller initiatives.

The JIESC supports aggregation of CBL loads at different plants under the expectation that this would make some Demand Side Management ("DSM") programs or generation projects economic. The JIESC argues that limiting load aggregation to operating facilities removes the incentive that load aggregation may provide to customers to shutdown individual facilities.

The JIESC disagrees with BC Hydro's proposal to determine demand charges based on CBL demand. The JIESC proposes that demand charges should be calculated as they currently are, based on actual metered demand at the customer's site. The JIESC argues that this method will send the appropriate price signal for use of the transmission system. For example, if an industrial customer purchased from an IPP instead of from BC Hydro, that customer's demand charge would remain the same as if the load had been supplied by BC Hydro. However, the JIESC argues that demand charges should be reduced when industrial customers make investments, such as cogeneration, that reduce their demand on the system. The JIESC proposes as well that aggregation of demand charges should be allowed because it would encourage customers to manage their combined peaks, ultimately reducing demand and benefiting transmission and generation systems.

Commercial Energy Consumers

The CEC submits that a stepped rate design should be consistent with the following requirements (CEC Final Argument, p. 53):

- The Tier 1 rate must be set at a rate that captures BC Hydro's low cost resource base.
- The Tier 2 rate must reflect the cost of new supply.
- The rate design must not shift costs among customers or impose new uncompensated risks on other customers.
- The rate design must be neutral with respect to customer choice of energy supplier (BC Hydro, IPP, or marketer), self-generation or DSM.
- The rate design must be easy to understand and implement with minimal regulatory process.

The CEC approach to stepped rate design would require that the Tier 1 / Tier 2 Split be derived on the basis of determining the Tier 1 and Tier 2 rates. The CEC proposes that the Tier 1 rate should be priced at the cost of all Heritage Resources. The CEC states that on this basis the Tier 1 cut-off point would equal 97 percent of CBL, with 3 percent of CBL available at the Tier 2 price.

The CEC believes that the Mid-C one-year forward price is only an appropriate price signal for shorter-term conservation efforts, not efficiency investments. On this basis, it argues that the anticipated 97/3 Tier 1/Tier 2 Split under its proposal is a correct starting point because it confines BC Hydro's Mid-C Tier 2 price to a relatively small volume. The CEC asserts that conservation efforts could run counter to the economic objectives of the Energy Plan; hence, it prefers that a lower percentage of Tier 2 consumption should be available to support these efforts.

The CEC proposes that a stepped rate design offer more than a single Tier 2 rate in order to provide the appropriate incentives for longer-term savings. In particular, the CEC proposes the establishment of a longer-term "Tier 2 investment price" to signal energy efficiency investments or IPP supply.

The CEC envisions that such a Tier 2 investment price should be matched with appropriate commitments to capacity, shape, duration, flexibility, and other terms and conditions as necessary. The CEC speculates that an appropriate measure of this price signal could be determined by monitoring a long-run marginal or incremental cost, referencing BC Hydro's offers to purchase non-Heritage Resources or establishing an iterative, least-cost bidding process for the right to serve the block of energy to be made available at the Tier 2 investment price. The CEC submits that the bidding process is the best approach. It submits that a Tier 2 investment price would not disadvantage new loads because it would be available to the best investment opportunities. It argues that the process appropriately balances supply and demand, mitigating any concerns that BC Hydro may have about maintaining margin-neutrality. The CEC asserts further that appropriate access rules will ensure that the Tier 2 investment price will not result in cost-shifting.

The CEC estimates that energy demand will grow to 7 percent of CBL in the "relatively near future". Such growth would be incremental to the 3 percent of Tier 2 consumption made available at the Mid-C price. The CEC proposes that growth in demand be priced at its Tier 2 investment price. However, it proposes that such a price should be made available to 7 percent of industrial CBL load immediately upon stepped rate implementation, not simply to the anticipated incremental growth as it occurs. This, the CEC argues, will account for the lag time associated with planning and delivering efficiency investments. The CEC submits that expansions in productive capacity should not be penalized, as is the case under a 10 percent CBL deadband. The CEC proposes that if it can be demonstrated that a customer's consumption growth is being driven by increases to its production capacity, then that customer's CBL should be increased, regardless of the level of its total consumption relative to its existing CBL plus 10 percent. The CEC proposes that in such situations CBLs should be adjusted annually.

The CEC also proposes that the CBLs of customers should be reduced where it can be demonstrated that declines in consumption between 3 percent and 10 percent of CBL are related only to capacity reductions (reductions up to 3 percent would never result in a CBL adjustment). The CEC contends that this would allow the implementation of the Energy Plan to avoid contributing to the loss of production, jobs, and economic growth in the name of administrative efficiency.

The CEC agrees with BC Hydro that the derivation of CBLs should not double count the benefits associated with any PowerSmart or CBG investments that coincide with pending or actual stepped rate implementation. The CEC accepts that CBLs should be adjusted to account for any PowerSmart or CBG investments funded by BC Hydro, but it believes that retroactive adjustments should be made on the basis of the value of energy savings relative to BC Hydro's initial funding of the programs.

The CEC supports load aggregation provided it does not result in facility shutdowns that cause cost-shifting to the other customer classes. The CEC asserts that load aggregation is of much less concern under its proposed framework for stepped rate design, given that only 3 percent of industrial load will be available for capacity reductions without a corresponding CBL adjustment. The CEC also proposed that buying pools be allowed.

CBT Energy

CBTE proposes a revenue-neutral stepped rate based on the following design considerations. The Tier 1 rate should be based on the average cost of Heritage hydroelectric resources, the Tier 2 rate should be based on the long-term cost of acquiring new supply, and the Tier 1/Tier 2 split should be derived as a function of the two rates and adjusted as necessary to recover changes in revenue requirements.

CBTE submits that BC Hydro's proposed short-term price signal for setting the Tier 2 rate does not meet the spirit of the Energy Plan and will not support the intended objectives of stepped rates. CBTE believes that a long-term cost is more appropriate for providing meaningful incentives under stepped rates.

CBTE proposes that the Tier 2 rate be based on a filed resource procurement plan prepared by BC Hydro's distribution line-of-business, reviewed by key stakeholders and approved by the Commission. CBTE believes that although a resource procurement plan would include gas price forecast uncertainties, a Tier 2 rate set on this basis would be less volatile than a one-year Mid-C price given the longer-time horizon on which such forecasts would be based. CBTE submits that future adjustments to the Tier 2 rate would only be considered when the distributor's procurement plan changes in a significant way, for example, through acquisition of a large block of electricity or expiry of a major contract with an IPP (Ex. 16-1, p. 3).

CBTE estimates that a Tier 1 rate set at the average cost of BC Hydro's hydroelectric Heritage Resources would equal $19/MWh. Assuming a Tier 2 rate equal to $65/MWh, CBTE estimates that the Tier 1 cut-off would be roughly 85 percent of CBL. CBTE submits that Tier 2 consumption equal to 15 percent of CBL, or roughly 450 MW, would provide sufficient incentives for conservation and IPP supply. CBTE proposes that to protect BC Hydro from stranded costs, the impact of any particularly large industrial load displacement could be evaluated by the Commission, at BC Hydro's request.

CBTE supports BC Hydro's proposed methodology for establishing CBLs. CBTE submits that if a CBL is changed, the respective Tier 1 and Tier 2 consumption allocations should be adjusted in proportion to the ratio between the historical and new CBL.

CBTE supports load aggregation with certain defined restrictions in line with the proposal that aggregation of CBLs should only be allowed for operating facilities.

Independent Power Producers Association of BC

The IPPBC proposes that the Tier 1 rate be based on the volume of all the Heritage Resources and their associated costs. The Tier 2 rate would be based on the non-Heritage Resources, for example, purchases from IPPs, or other sources of energy available and acquired by BC Hydro on a least cost basis. The IPPBC expects that the actual Tier 2 rate would be established by BC Hydro, or at a negotiated price under contract with an IPP.

Under this approach, the split between Tier 1 and Tier 2 is the actual split between Heritage and non-Heritage Resources. The IPPBC estimates that the Heritage Resources comprise about 87.5 percent of the total generation required to meet BC Hydro's current domestic load. This figure is based on the IPPBC's argument that output from the Heritage Resources would be set at 46,000 GWh, based on its assessment that this is the expected output from these Resources during average water years (as noted previously in section 2.1). The amount of Tier 2 energy, initially 12.5 percent of total generation, would be expected to increase gradually in the future as consumption levels increase.

The IPPBC argues that its design is beneficial because it is inherently revenue-neutral and not susceptible to arbitrage. It believes that it is also favourable because it allows for a billing approach that lets all BC Hydro Distribution customers see the difference between the cost of "old" and "new" electricity supply on their monthly bills. The IPPBC submits that its proposal creates a level playing field for the provision of energy in the Tier 2 market, thereby encouraging private sector investment in BC.

The IPPBC's proposal is indicative of its strong support for cost-based Tier 1 and Tier 2 rates for energy. Further, it submits that its proposal does not affect the underlying costs of the BC Hydro system, but rather provides a clear base for Heritage and non-Heritage cost of service models.

The IPPBC shares similar concerns to other parties regarding BC Hydro's proposal to base the Tier 2 rate on a one-year forward Mid-C price, which it states is not a liquid, published one-year forward price. It expects that the price would be volatile, leading to questionable outcomes for investments such as Demand Side Management or IPP supply.

The IPPBC argues that BC Hydro's concerns regarding cost-shifting and arbitrage are overstated. It submits that cost shifting will not be a concern if third party purchases do not exceed annual load growth, estimated at 1.6 percent in BC Hydro's May 2003 *Electricity Load Forecast*, or nearly half of the available market to IPPs (3.5 percent in the IPPBC's estimation). The IPPBC believes that it is difficult to envision how customers could be burdened with the costs of unutilized capacity if industrial load reductions are less than normal load growth. The IPPBC submits that if BC Hydro requires a one-year notice period, it can adjust its purchasing behavior to ensure there are no stranded assets resulting from third party purchases. Further, it notes that a one-year notice period would remove any BC Hydro concerns about cost-shifting that could result from industrial customers arbitraging daily loads between BC Hydro and third party supply. The IPPBC proposes that industrial customers should be allowed to choose a supplier other than BC Hydro Distribution for their Tier 2 requirements, effective immediately upon the adoption of stepped rates.

The IPPBC submits that concerns about cost-shifting and arbitrage are overwhelmed by the anticipated benefits of an appropriately designed stepped rate structure. It expects that, as the cost of new electricity supply increases, greater levels of conservation, energy efficiency investments or third party purchases by industrial customers will save the remaining customer classes the cost of newer, more expensive electricity.

BC Old Age Pensioners Organization

The BCOAPO generally supports BC Hydro's proposal. It agrees with the fundamental design idea that the priority should be to set the Tier 2 rate and the Tier 1/Tier 2 Split. This support underscores its interest to ensure that stepped rates meet the objectives as considered in the Energy Plan while not causing a shift in the revenue requirement allocation from transmission customers to other customer classes.

The BCOAPO submits that the appropriate proposal needs to ensure that there is no interclass or intraclass cost-shifting. The BCOAPO recognizes the divergence of opinions on the principles and design parameters of stepped rates, but it is convinced that on balance, the BC Hydro proposal is the most appropriate. However, the BCOAPO submits that the Commission should "only recommend qualified acceptance of stepped rates for transmission level customers at this time subject to reviewing the actual numbers in BC Hydro's 2004 applications" (BCOAPO Final Argument , p. 12).

BC Citizens for Public Power

The BCCPP is opposed to the implementation of stepped rates. It argues that stepped rates do not meet the stated objectives of the Energy Plan; they will neither increase the security and reliability of supply nor increase private sector opportunities.

The BCCPP argues that an increase in the number of companies serving a given area and load may increase, not decrease, the risk of system failure, thereby reducing energy security and reliability. Further, it argues that the process of contracting IPP supply could further diminish security and reliability because of the risk that contracted IPPs would be unable to complete projects that have displaced or delayed BC Hydro driven projects, such as Site C.

Other Intervenors

Other intervenors did not provide substantive submissions on stepped rates, because either they were primarily interested in Heritage Contract issues or they felt their positions were well represented by the submissions of other intervenors.

3.4 Applicability of Stepped Rates to Non-Industrial Customers

BC Hydro interprets the Energy Plan as requiring the application of the stepped rate to RS 1821, and all rates that are directly derived from RS 1821 including RS 3808, the rate under which Aquila purchases its power. BC Hydro notes that Aquila informally put forward a position that the stepped rate should not apply to it and that BC Hydro supports Aquila's position (Ex. 10, Tab "Aquila", Response 28.0).

Aquila is an investor-owned electric utility in south-central BC serving some 90,000 customers directly and an additional 50,000 customers indirectly through power sales to one investor-owned and five municipal utilities. Aquila offers retail access to both its industrial and wholesale customers. Ninety-four percent of Aquila's sales are to residential and commercial customers (Ex. 14-1, pp. 3-4, p. 10).

The total amount of power supplied by BC Hydro to Aquila makes up less than one-third of Aquila's total energy requirements, and is supplied under RS 3808. The amount of power available to Aquila under RS 3808 is capped at 200 MW. While the rates charged for power under RS 3808 are equal to the rates charged under BC Hydro's RS 1821, RS 3808 contains several features that distinguish it from RS 1821 (Ex 14-1, pp. 7-9).

Aquila submits that Policy Actions #14 and #21 relating to new rate structures for large electricity consumers are intended to provide incentives to BC Hydro's <u>end-use</u> customers (Aquila's emphasis) to use electricity in an economically efficient manner and thereby minimize the impact of market distortions. Aquila notes that it is a distributor of electricity and provider of transmission service and not an end-use consumer. It submits that applying stepped rates to Aquila will not enhance the goals of the Energy Plan and will increase Aquila's rates to its customers who already face rates higher than BC Hydro's (Ex. 14-1).

Aquila argues that if stepped rates were applied to Aquila, the entire decision that led to the creation of RS 3808 would have to be revisited. Aquila notes that it already faces a market signal rather than a blended signal in its cost of acquiring incremental resources and so it already faces a functionally stepped rate (T8: 1690, 1787). Aquila argues that applying stepped rates to it would be counter-productive since the Power Purchase Agreement between BC Hydro and Aquila achieves the results intended by the Energy Plan (Aquila Final Argument, p. 4).

Two other customers of BC Hydro: the City of New Westminster ("New Westminster", the "City") and the University of British Columbia ("UBC", the "University") submit that the stepped rate provisions should not apply to them.

New Westminster operates its own distribution utility. The City consumes some power for its own use, but distributes most of its electricity to residential and commercial customers. It has no industrial load. New Westminster's power supply is purchased from BC Hydro under a purchase agreement with BC Hydro that takes the form of an RS 1821 agreement, but which contains additional provisions necessary for a wholesale purchase agreement (New Westminster Final Argument, p. 3). The City states that self-generation could require legislative changes and a referendum, and that it is not currently considering self-generation. New Westminster submits that, as a distribution utility, stepped rates should not apply to it (Ex. 39).

The City states that it has maintained a policy that its ratepayers will see the same cost of electricity as those of neighbouring municipalities and argues that the imposition of stepped rates on the City would result in discriminatory treatment of its customers (New Westminster Final Argument, p. 5). The City further argues that as a wholesale customer, it already has options to choose a supplier other than BC Hydro and therefore stepped rates are not necessary to foster private power development and efficient consumer energy use. The City submits that the Commission can conclude that:

- a separate rate class is not necessary because customers with dramatically different non-mandatory market options already exist under RS 1821;
- those customers with non-mandatory options should be in a separate class; or
- the City's filed energy purchase agreement is sufficient to meet rate design and regulatory requirements (New Westminster Final Argument, p. 6).

BC Hydro supplies all electricity to UBC under RS 1821. The University then distributes the electricity to its buildings, land lease tenants and separate University businesses, which are billed by UBC for the electricity consumed. Approximately 55 percent of the electricity consumed is for academic and ancillary departments, and approximately 45 percent is for use by tenants. The University states that its energy demand is very weather dependent and the demand is therefore largely outside of its control. The University submits that its activities are more consistent with those of a utility than of an industrial customer and, as a utility, it should not be billed under a stepped rate structure by BC Hydro (Ex. 39).

The University states that it charges rates similar to BC Hydro rates for residential and commercial customers while the academic group funds and pays for their costs in a method that meets the Ministry of Advanced Education guidelines. UBC argues that stepped rates could increase rates charged by it to accommodate the new costs and such rates could be higher than BC Hydro rates for similar customers, leading to discriminatory treatment of UBC's residential and commercial customers. The University submits that adverse rate impacts to end-use customers could not necessarily be flowed through to those customers, leading to the absorption of increased costs by the University and reduced funding for academic programs and goals. Therefore, UBC would prefer a blended rate, which could be under either a new rate class or a supplement to RS 1821. UBC submits that the final decision as to the appropriateness of a rate class or rate design should be the result of a Rate Design application rather than as the result of evidence in the Inquiry (UBC Final Argument, pp. 4-5).

Both New Westminster and UBC agree with Aquila's interpretation of the Energy Plan and support Aquila's argument that the stepped rates are intended to apply to large end-use customers rather than those BC Hydro customers who distribute much of their electricity to others.

The JIESC commented that while it does not necessarily oppose exclusion of some customers from stepped rates there must be good reason to do so. It argued that the Commission's views on acceptable reasons for such exemptions should be made clear and that excluded customers should form a new rate class with the rates for that class based on the cost of serving it.

3.5 Time-of-Use Rates

Policy Action # 21 of the Energy Plan states, in part (p. 33):

> The BC Utilities Commission will conduct a hearing to develop new stepped and time-of-use pricing for BC Hydro's industrial and large commercial customers….Time-of-use rates will encourage customers who can manage the timing of their electricity use to shift consumption to low-priced off-peak periods. Both rate structures will benefit British Columbians by deferring the environmental impacts of new power development.

Term of Reference No. 4 for this Inquiry directs the Commission to make specific recommendations relating to the changes it believes are desirable in the rates of transmission voltage customers to accomplish the objectives of the Energy Plan, including:

> 4(b) The detailed provisions of new stepped rate schedules as more fully described in the Energy Plan….

BC Hydro's submissions to this Inquiry did not include a proposal on time-of-use rates. BC Hydro indicated that it questioned whether there was any particular need to deal with time-of-use rates in the Inquiry, notwithstanding the reference to such rates in the Energy Plan, given that BC Hydro has the ability now to offer time-of-use rates (T3: 491). BC Hydro counsel suggested that the Terms of Reference do not require the Commission to make particular recommendations on time-of-use rates (T3: 492). The Commission Panel responded that there are provisions in the Terms of Reference that give it considerable latitude with respect to defining the scope of the

Inquiry, and noted further that it would not discourage questions on time-of-use rates during the hearing (T3: 496).

BC Hydro indicates that the second tier of a stepped rate could include a time-of-use component and such a rate could be another pricing option in a two-tier regime (Response to BCUC IR1: 79; T6: 1237; T6: 1399-40). BC Hydro suggested, however, that another reason it did not include time-of-use rates as a stepped rate pricing option was that it intended a smooth and practical implementation of Policy Action # 21. In BC Hydro's estimation, this would require implementing a relatively simple stepped rate proposal initially, while leaving it open to modification as experience and learning were acquired as to the effectiveness of the stepped rate (T7: 1414-7).

BC Hydro offered a Time-of-Use Pilot Program during 2000 and 2001. It filed two evaluation reports of this program (Exhibits 51 and 52), which summarized program impacts, areas for improvement, and specific pricing considerations. BC Hydro noted that the mechanics of time-of-use rates are not difficult to design and implement for industrial customers because all the meters are there and the relevant information is readily at hand (T6: 1214-5). BC Hydro understands that its customers would desire that time-of-use rates be voluntary. BC Hydro notes that it could design a time-of-use rate, as a stepped rate pricing option, that reflected its opportunity costs across different time periods, without increasing the risk of arbitrage relative to a flat Tier 2 rate (T7: 1421).

The JIESC supports the implementation of a voluntary time-of-use rate on the same schedule as stepped rates (T8: 1654, T8: 1759, JIESC Final Argument, p. 36). The JIESC proposed that in addition to the mandatory Tier 2 rate, there would be a voluntary alternative available to industrial customers as part of the stepped rate design where the variations by time of day that went into the flat Tier 2 rate were recognized (T8: 1655). A voluntary rate available to interested customers would not penalize customers with little or no flexibility in their production scheduling. The JIESC believes that time-of-use rates may be useful to change patterns of consumption on Vancouver Island and to reduce the demand of industrials that have storage on their systems, or otherwise have scheduling flexibility. The potential benefit is cost savings to all customer classes from a reduced need for new generation or transmission (JIESC Final Argument, p. 36).

CBTE makes no specific submission on time-of-use rates other than to state its support that the Commission Panel should include recommendations on such rates (T9: 1934). The CEC submits that the Commission Panel should recommend that BC Hydro be directed to consult with customers about time-of-use rates, and subsequently file a time-of-use rate application in conjunction with a stepped rate filing (CEC Final Argument, p. 14).

3.6 Commission Panel Views

Stepped Rate Design

The stepped rate is defined by three parameters: a Tier 1 rate, a Tier 2 rate, and an amount of energy allocated to each rate (the Tier 1/Tier 2 Split). The evidence and argument of Inquiry participants highlighted the merits and anticipated impacts of alternative design options for setting these parameters. The Commission Panel's recommendations on stepped rates have considered the merits of these design options in the context of the objectives of the Energy Plan and its specific imperatives for stepped rates. The focus of the debate has highlighted that policy-level decisions on overall stepped rate design are currently required, while more detailed considerations would be determined through a Commission review of a stepped rate application.

Tier 2 Rate

BC Hydro specified three principles for a stepped rate; it should be mandatory, revenue-neutral and margin-neutral. BC Hydro proposed that the Tier 2 rate should equal its short-term opportunity cost, primarily to support its principle that the rate should be margin-neutral and limit cost-shifting between customers, or between customers and the shareholder. BC Hydro proposed that an effective proxy for its short-term opportunity cost is a one-year forward Mid-C market price.

Although there was near consensus that the Tier 2 rate should reflect BC Hydro's opportunity cost of new supply, there was dispute about whether that opportunity cost should be measured according to short-term or long-term opportunities. Key to this debate was significant argument that suggested a short-term price signal, such as a one-year forward Mid-C price, would not stimulate purchases of IPP supply or otherwise spur investments in energy efficiency and customer-based generation.

The Commission Panel agrees with BC Hydro and several intervenors that the Tier 2 rate parameter is of primary importance to the design of a stepped rate to provide a price signal of the cost of new supply. However, the Commission Panel believes that a Tier 2 rate based on a volatile short-term, one-year forward Mid-C price would not adequately signal the types of behaviour or investment contemplated by the Energy Plan as the outcome of stepped rates. The Commission Panel believes that an appropriately designed Tier 2 rate based on the long-term cost of acquiring actual new energy supply would be more supportive of the objectives of the Energy Plan, as was intended in the Policy Actions for stepped rates. Further, the Commission Panel notes that the Energy Plan does not refer to the principle of margin-neutrality as a necessary guide for stepped rate design. Nonetheless, the

Commission Panel does not expect an appropriately designed stepped rate to entail a significant risk of cost-shifting.

Therefore, the Commission Panel concludes that the Tier 2 rate should reflect the long-term opportunity cost of new supply defined with reference to BC Hydro's expected resource acquisition costs. The Commission Panel concludes that there should be a single Tier 2 rate initially; with the possibility of multiple rates should experience indicate it to be desirable.

Tier-1/Tier 2 Split

BC Hydro proposed that the Tier 1/Tier 2 Split should be fixed at 90/10, underscoring its determination that it is more important to set this parameter and then derive the Tier 1 rate, than the reverse. The Commission Panel agrees that a 90/10 split ensures that the Tier 2 quantity is sufficiently large to satisfy the Energy Plan's objective of providing better price signals for conservation and energy efficiency, while not so large as to expose BC Hydro to significant price or volume risk. Further, the Commission Panel accepts that setting the Tier 1/Tier 2 Split may increase the stability of the Tier 1 rate, with associated implementation and administrative benefits.

The Commission Panel is cognizant that fixing the Tier 2 rate and the Tier 1/Tier 2 split may result in unacceptable increases to the Tier 1 rate if load growth is served through new supply resources. Therefore, the Commission Panel concludes that stepped rates should be initially designed with a 90/10 Tier 1/Tier 2 Split, with the provision that the Tier 2 percentage be allowed to increase (upon a rate design application) to reflect the percentage of actual Tier 2 volumes when it grows to be greater than 10 percent of total BC Hydro resources.

Tier 1 rate.

With the Tier 2 rate and the Tier 1/Tier 2 Split specified, the constraint of revenue neutrality for transmission level customers determines the Tier 1 rate. The Commission Panel accepts the determination of the Tier 1 rate as a consequence of the determinations made for the Tier 2 rate and Tier 1/Tier 2 Split.

Customer Baseline Load

The ultimate design of a two-tiered stepped rate that adheres to the principle of revenue-neutrality requires that a CBL be determined as a reference point for historical energy consumption levels. Participants in this hearing accept that CBLs need to be determined for industrial customers to implement stepped rates.

The Commission Panel accepts the proposals of BC Hydro and the JIESC, and the general consensus among all Intervenors, that the methodology to derive CBLs for energy consumption should be based on that employed under Real-Time Pricing (RS 1848). Therefore, the Commission Panel believes that a stepped rate design should include a provision that CBLs should be based on an average of the last three years of energy consumption, but that allowances should be made for anomalies in the production cycle of the customer. Each individual CBL of RS 1821 customers should be adjusted pro rata, such that the sum of the individual CBLs equals the existing total consumption of RS 1821 customers.

The Commission Panel supports the notion that customers should be given some flexibility to manage normal variations in load around their CBLs. This will provide a degree of certainty to BC Hydro and its customers, streamline the administrative process, and otherwise protect BC Hydro and its customers from undue burden. Therefore, the Commission Panel concludes that CBLs should not be changed so long as customers consume within a plus or minus 10 percent deadband around CBL.

In the Commission Panel's view, should stepped rates be implemented, the Commission should approve CBLs and subsequent adjustments to them, and resolve any associated disputes. The Commission Panel determines that BC Hydro should propose, as part of a stepped rate application, explicit conditions under which CBL adjustments should or should not be made when consumption is outside of a plus or minus 10 percent deadband. As part of its proposal, BC Hydro should specify the mechanism under which new load or new customers would be incorporated into a stepped rate pricing structure.

Load Aggregation

Load aggregation in the context of stepped rates is the aggregation of historical loads across a customer's multiple facilities into a single CBL on which stepped rates would then be based for that customer. Load aggregation would be of benefit if it improves the economics of specific efficiency investments, self-generation initiatives, or IPP purchases. Such investments may be uneconomic on a unit cost basis relative to the avoided cost, or Tier 2 rate, unless a greater amount of potential energy savings were available at little or no incremental cost. A larger CBL available under load aggregation would provide a greater amount of energy priced at the Tier 2 rate. The economics of such investments could improve to the extent that additional Tier 2 energy savings lowered the unit costs of the investments.

Allowing load aggregation would have a negative public impact if it simply permits a customer to close a facility, rather than make a defined investment, to achieve the benefit of reduced consumption from BC Hydro. This result could inappropriately shift costs to other customers or customer classes, or to the shareholder.

The Commission Panel concludes that the likely benefits of load aggregation for operating facilities only are aligned with the objectives of the Energy Plan.

Demand Charge

The Commission Panel recognizes that the implementation of stepped rates is intended to meet objectives that by their nature would result in customers changing the amount of load taken from BC Hydro, through self-generation or IPP purchases. Under these circumstances, it is important to consider how BC Hydro's transmission costs should be appropriately recovered. The main issue is whether the demand charge should be collected on a baseline level of capacity usage (CBL demand) or charged on the basis of actual demand.

The Commission Panel is persuaded that transmission cost charges should be based on actual demand. Basing the demand charge on actual demand provides the incentive for customers to invest in load factor improvement or self-generation, without hindering BC Hydro's revenue recovery in the long-term. It is in the interest of all customers to improve the efficient use of transmission capacity (through reduced peak consumption, for example). It would be appropriate for BC Hydro in a revenue requirements filing to apply to correct any under-collection of transmission costs that may result from such customer behaviour (which may be the case if, for example, BC Hydro has not anticipated this outcome in the forecasts of previous filings). In the alternative, under a CBL demand, self-generating customers would continue to pay the same demand charges, regardless of their efforts to reduce demand from BC Hydro. This runs counter to the objectives of stepped rates.

The Commission Panel concludes that until such time that transmission cost charges are determined through BC Hydro and BCTC revenue requirement and rate design applications, demand charges under stepped rates should continue as they are currently levied under RS 1821.

Renewal / Review Provisions

The Commission Panel believes the stepped rate structure, implemented according to the principles it has set forth, serves the Energy Plan by encouraging transmission customers to invest in energy conservation and self generation or by making purchases from IPPs. At the same time, it encourages the private sector to develop new generation. However, these goals do entail risk for BC Hydro.

Two risks arise with the implementation of stepped rates. First, establishing the Tier 2 rate at long-term acquisition cost increases the likelihood of discrepancy between it and BC Hydro's procurement cost, to the extent that there is a component of short-term purchases in a given time period. Second, the possibility was raised that a Tier 2 rate reflecting market price might deter new investment or drive it to other jurisdictions (T3: 664). The latter seems unlikely, however, inasmuch as the component of the rate structure based on Heritage Resources will contribute to a lower average for the total rate.

The discussion of the cut-off parameter noted that, given load growth, a rigid 90/10 cut-off would lead to an increasing Tier 1 rate, thereby obscuring the value of the Heritage Resources while understating the opportunity cost of new supply. Accordingly, future adjustment may be appropriate.

Given initial uncertainty over the risk that stepped rates may pose for BC Hydro, it will also be desirable to monitor the effect of stepped rates. In the Commission Panel's view, at the end of a three-year period the Commission should evaluate the effect of stepped rates and advise Government.

Applicability of Stepped Rates to Aquila, New Westminster, and UBC

Although there are characteristics of RS 1821 in Aquila's RS 3808, it is a separate rate. The Commission Panel notes that Aquila's position is supported by BC Hydro even though its technical reading of the Energy Plan differs from that of Aquila. The Commission Panel agrees with both Aquila and BC Hydro that a stepped rate should not be required to apply to Aquila at this time.

The Commission Panel also concludes that the customer characteristics of New Westminster, as a distribution utility, more closely resemble those of Aquila than that of an industrial customer. Moreover, while New Westminster is served under a form of RS 1821, the agreement between BC Hydro and the City contains additional provisions for service to a wholesale customer. Therefore, the Commission Panel concludes that New Westminster should be exempted from the application of stepped rates at this time.

UBC has customer characteristics of both a distributor and an industrial or large commercial customer. The Commission Panel is persuaded by the arguments of the University that application of stepped rates to UBC could lead to customers served by it being charged higher rates than neighbouring residential and commercial customers served directly by BC Hydro. The Commission Panel is also persuaded by the University's concerns that if it is unable to pass-on higher costs caused by stepped rates to its customers, then those costs might have to be absorbed by the University to the detriment of its programs. Therefore, the Commission Panel concludes that stepped rates should not be applied to UBC at this time, and that the appropriate rate structure for the University be reviewed in BC Hydro's rate design hearing

Time-of-Use Rates

Time-of-use rates are considered in Policy Action #21 as one rate design option to support achieving the objectives of the Energy Plan. The Commission Panel recognizes that Policy Action #21 contemplates that the Commission will conduct a hearing, in part, to develop new time-of-use pricing for BC Hydro's industrial and large commercial customers. The Commission Panel notes that time-of-use rates are not specifically referred to in the Terms of Reference for this Inquiry. The Commission Panel agreed with the submission of BC Hydro that the Terms of Reference do not require the Commission to make particular recommendations on time-of-use rates. However, the Commission Panel also decided as a principle not to limit questions relating to time-of-use rates.

The Commission Panel agrees with intervenor submissions that time-of-use rates would be beneficial to BC Hydro and its customers, both directly and indirectly. The JIESC indicated that some large industrial customers would likely benefit from the time-of-use rates, which could result in benefits also accruing to BC Hydro from more efficient use of the transmission system. The Commission Panel believes that the design and implementation of time-of-use rates has been adequately tested through BC Hydro's recent Time-of-Use Pilot Program. Therefore, the Commission Panel concludes that BC Hydro should file a time-of-use rate application as part of, or concurrent with, a stepped rate application for transmission voltage customers.

4 INDUSTRIAL ACCESS TO THIRD PARTY SUPPLY

4.1 Submissions and Argument

The Terms of Reference direct the Commission to make specific recommendations regarding the rates of transmission voltage customers to accomplish the objectives set out in the Energy Plan, including:

> The terms and conditions that should govern existing and new large industrial or transmission rate customers' access to transmission for the purpose of acquiring power from other energy suppliers' generation; and
>
> The principles which should govern the terms and conditions under which large industrial or transmission rate customers wishing to obtain generation from alternate suppliers may decline to obtain service from BC Hydro or may apply to obtain service from BC Hydro thereafter. (Ex. 2, subparagraphs 4(a) and 4(c))

The ability of an end-use customer such as a large industrial or transmission rate customer to purchase power for some or all of its own needs is commonly termed "retail access". This Report adopts that definition. During the Inquiry, two related terms were used: "Transmission access" and "Generation access". Transmission access means the access by an IPP or a marketer to transport power on the BC Hydro transmission system, whether for the use of a BC Hydro customer or for delivery to a customer outside of the BC Hydro service area. Generation access refers to the rights and obligations of BC Hydro customers that may wish to obtain service from a supplier other than BC Hydro, and that may wish to return to BC Hydro supply at a later date.

The IPPBC estimates that the total market available to the IPP and marketer community, assuming that competition for the industrial market share would be limited to the Tier 2 energy block, would be approximately 1,892 GWh of load and 230 MW of capacity. As a proportion of the total BC Hydro load, the IPPBC estimates that these amounts equal approximately 3.5 percent of energy consumption and 2 percent of capacity. Competing against IPPs and marketers for this portion of the load would be DSM, self-generation and BC Hydro/Powerex (Ex. 27, p. 13). The IPPBC further states that securing electricity purchase contracts will be difficult for several reasons, including: the inherently lower cost structure of BC Hydro Tier 2 electricity; the need to clearly demonstrate savings to customers; the tendency of customers to undertake DSM first; the reluctance of customers to sign long-term supply contracts; and potentially attractive self-generation and import options (Ex. 27, p. 17).

In order to have access to this limited market, the IPPBC argues that industrial customers should be allowed to choose a supplier other than BC Hydro for their Tier 2 requirements effective immediately upon the adoption of stepped rates. CBTE and the JIESC agree with the IPPBC that retail access for industrial customers should not be delayed.

BC Hydro argues that the derivation of distinct rates for ancillary services and "...more robust terms and conditions to avoid arbitrage between supply from BC Hydro and other sources" need to be developed before retail access is permitted. BC Hydro submits that responsibility for development of access principles relating to generation access and the prevention of generation arbitrage are the exclusive responsibility of BC Hydro. It considers the development of rates, terms and conditions of access to transmission service to be the responsibility of BCTC (Ex. 29, p. 2). Therefore, BC Hydro argues that the Commission should recommend to Government that retail access not be introduced until BCTC assumes responsibility for open access transmission and can make adjustments to the rates, terms and conditions of access to transmission service.

Ancillary Services

Ancillary services are interconnected operations services that are required to transfer electricity between a buyer and a seller, which a transmission provider must include in an open access transmission tariff. BC Hydro currently offers the following ancillary services to users of its transmission system under its WTS tariff (Ex. 10, Response to CEC, question 30.0; Ex. 8-2, p. 10):

- System Control and Dispatch;
- Reactive Supply and Voltage Control;
- Regulation and Frequency Response;
- Contingency Reserve – spinning;
- Contingency Reserve – supplemental;
- Energy Imbalance; and
- Compensation for Transmission losses.

BC Hydro argues that the prices at which various ancillary services would be supplied by BCTC need to be determined before customers can make full use of retail access. The IPPBC submits that IPPs cannot make sales to industrials (Ex. 27, p. 15) or compete on a level playing field with BC Hydro and Powerex without access to ancillary services on the same terms and conditions. In response to IPPBC questioning, BC Hydro stated that it is obligated to provide ancillary services to third parties in support of WTS and it will continue to do so if required. (T4: 865).

BC Hydro also supplies standby power under RS 1880: Transmission Service – Emergency, Maintenance and Special Supply. BC Hydro submits that while the rate should be retained for existing generation, it should be modified to make it appropriate for the stepped rate (Ex. 8-2, p. 11).

The IPPBC submitted that an industrial customer could use RS 1880 to reduce its "demand charge spikes" due to normal outages at self-generation units. It considered that lack of IPP/marketer access to the 1880 rate would violate the principle of a level playing field by reducing the cost of load shaping and backstopping for self-generation relative to IPPs and other third party providers.

Energy Imbalances

BC Hydro states that because the stepped rate virtually assures that customers who choose to pursue retail access or CBG will continue to take part of their load from BC Hydro, it needs a way to distinguish how much energy is taken from BC Hydro and how much is taken from the alternative supplier (T6: 1316-1317; BC Hydro Final Argument, p. 33). BC Hydro submits that if retail access is implemented before new imbalance charges are developed by BCTC, BC Hydro will need to establish an energy imbalance charge (Ex. 8-2, p. 11).

To deal with imbalances, BC Hydro would require a customer taking alternative supply to provide a forecast hourly schedule of the load shape being delivered to the customer and would charge an energy imbalance charge to the extent that the schedule was not actually supplied (i.e. under-delivery) within a range, or "deadband". BC Hydro suggests that the width of the deadband should be comparable to the +/-1.5 percent deadband in the WTS tariff, but need not be that precise amount.

BC Hydro would not compensate the alternative supplier for positive imbalances (i.e. over-delivery) outside the deadband, arguing that this would create an incentive for parties to provide BC Hydro with large amounts of unneeded generation, potentially creating reliability problems due to unscheduled deliveries (Ex. 29, p. 6; BC Hydro Final Argument, pp. 13, 33-34).

BC Hydro submits that under retail access an appropriate imbalance charge for negative balances would be the higher of the prevailing Tier 2 rate and the cost of acquiring the imbalances from the market (Ex. 29, p. 6). BC Hydro recognizes that whether the imbalance charge is set at the higher of the market price or the Tier 2 Price, or just the market price, is a question of which party would benefit from the opportunity cost of the energy used to correct the imbalance. BC Hydro argues that an imbalance charge that is just market plus administrative costs would shift the benefit to the IPP/customer at the expense of BC Hydro and its other customers (BC Hydro Final Argument, pp. 34-35).

CBTE states that it generally agrees with BC Hydro's position on generation access principles except on the issue of imbalance charges. CBTE considers BC Hydro's proposed asymmetrical treatment of imbalances to be unnecessary and unfair to IPPs. CBTE argues that the price paid for imbalances should be symmetrical (CBTE Final Argument, p. 27).

The JIESC argues that imbalance charges should only be imposed for imbalances outside of a reasonable band. The JIESC argues that imbalance charges should be market-based and symmetrical for both negative and positive imbalances. Anything else, in the JIESC's submission, puts the IPP or the industrial customer at too much risk to proceed (JIESC Final Argument, p. 31).

Storage

A valuable component of the BC Hydro Heritage Resources is the ability to "store" electricity, in a practical sense, by manipulating the accumulation, storage and use of water in the reservoirs of BC Hydro's hydroelectric system for generating purposes. A letter from the Ministry of Energy and Mines dated May 12, 2003 clarifying the intent of the Energy Plan in the context of the Inquiry made the following comment about storage.

> The storage system is a key component of the heritage assets, which are first and foremost dedicated to domestic customers. The surplus capability of the storage system is, and will continue to be, used to optimize the economic value of the publicly owned system to provide benefits to BC Hydro customers and the provincial shareholder. This means the value of electricity being acquired by distributors under competitive processes will be a function of the timing, firmness, and reliability of the power being offered by private sector developers. (Ex. 2-2)

BC Hydro takes the position that Exhibit 2-2 made it clear that questions of IPP or third party access to storage is beyond the Terms of Reference of the Inquiry (T6: 1244).

The IPPBC disputes BC Hydro's characterization of the letter and submits that it was not a letter from the Minister and there was no evidence that it was written on behalf of the Minister (T6: 1245). The IPPBC argues that if the BC Hydro group of companies has access to storage and the IPPs do not, then the IPPs are not competing on "...a level playing field" (T11: 2276). The IPPBC argues "it should be made clear that the definition of ancillary services includes storage on the same basis that the BC Hydro group of companies has access to it either under the Powerex contract or internally" (T11: 2277).

The IPPBC raises a further concern about how storage would be provided as an ancillary service given that ancillary services are a transmission issue, and consequently would be expected to be part of a BCTC filing, while storage is a generation issue. In the view of the IPPBC, BCTC should be a party to the Heritage Contract (T11:

2278-79).

Availability of Transmission Capacity

The IPPBC also argues that if industrial customers switch from BC Hydro supply to IPP supply, there should be space available on the transmission system for the IPP sales to those industrial customers, because currently space is being used to deliver the power to them. The IPPBC requests that the Commission make recommendations with respect to availability of transmission capacity, so that the Government can issue a response that would remove any potential Commission concerns about "...transcending its regulatory boundaries" in ruling on the issue. The IPPBC submits that it is not looking for anything discriminatory, but is simply asking that rules be put in place so that another party, such as Powerex or BC Hydro, cannot book all the transmission capacity (T11: 2280-81).

Interim Access

BC Hydro states that, if the Commission recommends retail access prior to 2005, the most straightforward way to provide such access would be for the customer to take its entire load to the wholesale market and make use of BC Hydro's existing Point-to-Point ("PTP") wholesale transmission tariff. However, for several reasons, BC Hydro considers use of the PTP tariff to be an impractical solution and one that would not encourage retail access to develop (Ex. 29, p. 5). Chief among these reasons are the level of the PTP rate, complex issues that arise for customers that wish to serve only a portion of their load through third party supply, and the fact that BC Hydro considers its current WTS ancillary services charges to be inadequate for increased use due to retail access.

BC Hydro recommends that, if the Commission believes that retail access should be made available immediately, that such access should be made available under BC Hydro's Network Integration Transmission Service ("NITS") tariff (Ex. 29, p. 5). In order to use retail access under NITS, an industrial customer would need to make a bilateral arrangement with an IPP or marketer for energy supply. BC Hydro would nominate the supplier as a Network Resource. BC Hydro and the customer would have to agree to a forecast hourly schedule of generation to ensure that the shape of the energy supply was appropriate for the customer load and to enable BC Hydro to calculate imbalances (Ex. 29, p. 6; BC Hydro Argument, p. 33).

To prevent seasonal arbitrage, BC Hydro proposes to require customers to commit to a NITS arrangement for at least one year. BC Hydro also stated that a daily arbitrage risk would exist if direct access customers could choose between taking service from BC Hydro at the Tier 2 rate or from a third party supplier on a daily basis

(Ex. 29, p. 7). BC Hydro agreed that the introduction of an appropriate energy imbalance charge would mitigate the risk of arbitrage (T6: 1314-18).

The JIESC acknowledges that developing opportunities for IPPs in BC to do business with industrial customers as contemplated in the Energy Plan will require resolving issues of price, shaping, quantity, availability, back-up or reserves, transmission and load imbalances. The JIESC also accepts that if industrial customers wish to go to a third party supplier, when that is possible, such customers must give reasonable notice before leaving and returning (JIESC Final Argument, p. 31).

The JIESC recommends that access principles be limited to specifying the notice that should be given before an industrial customer leaves or returns to BC Hydro supply, and that RS 1821 Demand Charges cover IPP deliveries to industrial customers until BCTC has approved tariffs. Additional transmission charges should be limited to symmetrical market-based imbalance charges (JIESC Final Argument, p. 31).

Competition from PowerSmart, CBG and Public Corporations

The IPPBC argues that entities, such as CBTE, Columbia Power Corporation and BC Hydro (through Powerex, PowerSmart, CBG and the like) that receive special advantages or support from the Government or taxpayers should not be allowed to compete with IPPs in the Tier 2 market. The CEC states that it is unfair competition for the IPPs if BC Hydro is financing some options and not others, but the CEC submits that the solution is not necessarily to eliminate all other competition to the IPPs. The CEC argues that BC Hydro should be required to finance all options equally on a non-discriminatory basis to all sources, and that BC Hydro should perhaps be required to restrict its funding initiatives and restrict its demand-side management (PowerSmart) activities to education, awareness and promotion (CEC Final Argument, p. 35).

The JIESC argues that PowerSmart and CBG initiatives result in projects being implemented which otherwise might not occur and that such targeted initiatives should be continued (JIESC Final Argument, p. 37).

4.2 Commission Panel Views

BC Hydro does not support implementation of retail access on an interim basis prior to amended BCTC transportation service tariffs being in place. BC Hydro has also indicated that it could file its terms and conditions for generation access principles shortly after BCTC's transportation service rates are in place allowing retail access to be implemented on a permanent basis, likely by December 2004. BC Hydro considers retail access to be a complex issue with many implications, and cautions against implementing retail access on a piecemeal basis (T3: 628-629; T6: 1180-1181; BC Hydro Final Argument, p. 32). BC Hydro was generally supported in this regard by the BCOAPO (BCOAPO Final Argument, p. 13).

The JIESC, the IPPBC, CBTE and the CEC support implementing retail access more quickly. The CEC argues that the principles for retail access are available to the Inquiry and asks the Commission to recommend that BC Hydro be directed to bring forward retail access principles by March 31, 2004 based on the NITS tariff and that any customers who pursue retail access under the interim provisions be guaranteed to be able to use it for the duration of the project (CEC Final Argument, pp. 55, 82).

The IPPBC submits that there is a need for certainty in the rules for retail access (T2: 379). It agrees that temporary access principles are imperfect and would likely be a detriment to investment in new generation by IPPs, unless the Commission can provide interim retail access that allows the interim provisions to be maintained or “grandfathered” for those IPPs who engage in contracts to supply industrial customers under the interim provisions. The IPPBC indicates that there are several other conditions that it considers necessary before IPPs are likely to show interest in building new generation, including access to transmission capacity for domestic and export sales and access to BC Hydro’s storage (T7: 1534-1535; T11: 2319-2323).

The Commission Panel recognizes and supports the wishes of larger volume customers and IPPs to have the option of retail access available to them as soon as possible. That such access should be made available to them is clearly an objective of the Energy Plan and the Terms of Reference. However, it is equally important that the introduction of retail access not be rushed forward in a way that may lead to its failure. The potential benefits or costs of implementing retail access on a short-term, interim basis depend on whether interim measures can be put in place that allow, in a practical sense, retail access to occur while preventing potential arbitrage opportunities and cost-shifting between customer classes.

For these reasons, the Commission Panel concludes that interim retail access principles are likely to remain mostly unused, and thus will do little to provide encouragement to IPPs and marketers to compete for the Tier 2 industrial load. Without resolution on final BCTC Transmission Service and Ancillary Service charges, the certainty looked for by IPPs will not be present. Furthermore, risks of cost shifting from IPPs or industrial customers to BC Hydro or other customer classes would exist. The Commission Panel outlines in Chapter 5 a schedule for filings required to implement permanent retail access.

The Commission Panel accepts the arguments of the JIESC that targeted programs such as PowerSmart and CBG should continue, but recognizes that such programs diminish the load available for IPPs. However, Policy Action #20 directs electricity distributors to pursue clean energy, including efficiency improvements at existing facilities and cogeneration. Policy Action #23 (removing a disincentive for energy distributors to invest in conservation and energy efficiency) is consistent with utility investment in and expansion of programs such as PowerSmart.

The Commission Panel concludes that such programs should be allowed where a benefit to the ratepayers can be clearly demonstrated, or where the programs are aimed at saving or generating specific quantities of power in order to meet Clean Electricity targets. To balance the concerns of the IPP community and the goals of the Energy Plan, the Commission Panel believes that defined limits should be created for financing programs such as PowerSmart and CBG. The Commission Panel does not believe it is appropriate for it to make recommendations on the IPPBC requests that entities such as CPC, CBTE and Powerex be restrained from competing for Tier 2 industrial demand.

The Commission Panel is not persuaded that storage should be offered to third parties as a tariffed service. BC Hydro's storage is created by Heritage Resources and the benefits of those resources should go to the Heritage Beneficiaries. To provide those benefits on a cost of service basis would be to transfer the incremental benefits of those resources to parties other than the Heritage Beneficiaries. In the view of the Commission Panel that would be contrary to the intent of the Energy Plan.

5 COMMISSION PANEL RECOMMENDATIONS

The Terms of Reference set out two prime initiatives. First, benefits attributable to the existing low-cost electrical system are to be secured for British Columbians by means of a Heritage Contract. Second, more efficient use of energy resources and private investment in new generation are to be fostered by a stepped rate structure for transmission voltage customers. In normal circumstances, these two initiatives would compete against each other, but the stepped rate proposal allows the conservation and customer choice objectives to be achieved while maintaining low electricity rates for British Columbians.

The Energy Plan heralds a period of substantial renewal and change in British Columbia's Energy industry. Although the Energy Plan states that it will be fully implemented in 2004, it also called for this Inquiry to assist the Government in making more specific policy directions prior to the revenue requirements hearing of BC Hydro (Energy Plan, p. 11, 27). Many of the Policy Actions require specific determinations by the Commission after the Government responds to this Report. Policy Actions that relate to matters that require Commission Decisions before the end of 2004 include:

- Policy Action #5: The BC Utilities Commission 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 #15: The BC Hydro Transmission Corporation will improve access to the transmission system and enable IPP participation in US wholesale markets.
- Policy Action #16: The BC Utilities Commission will determine the terms and rates for this new transmission entity.
- Policy Action #21: New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.

The fifth recital of the Terms of Reference also places the Inquiry in the context of future proceedings:

> Whereas the Energy Plan contemplates that the Commission should conduct an inquiry to develop and refine certain policy areas relating to regulation of BC Hydro prior to the commencement of its review of BC Hydro's rates…

All of the recommendations are anticipated to be the subject of Commission proceedings in the next eighteen months.

There was a high degree of consensus amongst the participants on the broad policy issues. The BC Hydro proposal for a Heritage Contract had the support of almost all participants except CBTE. Many technical issues require determinations, but a significant issue for the Government will be the allocation of Trade Income. All of the customer groups supported BC Hydro's proposal that all Trade Income up to $200 million per year be allocated to the Heritage Beneficiaries. This allocation maximizes the benefits to all customers, but the Commission Panel heard little other evidence on the appropriate sharing of Trade Income between Powerex and the Government. A BC Hydro policy witness stated:

> As I said earlier, I think yesterday, our view in this from the beginning was, our main concern must be to maximize the total amount of wealth. The question of where it goes is really, to us, to BC Hydro is actually a secondary issue. More for the government and the Commission to discuss (T4: 743).

Trade Income needs to be considered in light of this policy testimony. In developing its proposal, BC Hydro made decisions that sought to ensure that there was an alignment of the interests of Powerex and BC Hydro's Generation and Distribution lines of business to maximize the total amount of wealth. The allocation of this wealth between the Government and BC Hydro's customers was a secondary consideration in BC Hydro's proposal.

When exercising its jurisdiction under the Utilities Commission Act ("UCA"), the Commission makes determinations that often "strike a balance" between customer and shareholder interests. BC Hydro's counsel stated that the "resolution of that [Trade Income] … is the biggest change that the regulatory model introduces and it's a far from trivial change. I think it's a really significant change" (T11: 2253). In making recommendations on the allocation of trade revenue pursuant to Term of Reference subparagraph 3(h)(ii), the Commission Panel recognizes that the interests of the shareholder were not represented.

In its recommendations regarding stepped rates, the Commission Panel places emphasis on the necessity of encouraging investment in new supply. This manifests itself in the recommendation that the Tier 2 rate should relate to the total long-term cost of new supply and should be measured by expected acquisition cost. Recognizing the innovative nature of stepped rate design, the Commission Panel's recommendations make provision for an evaluation report to Government after three years.

The Commission Panel is pleased with the extensive response to the Inquiry. Representatives from all BC Hydro customer groups, the Regional Districts, IPPs and other public interest groups participated in all phases of the proceedings. The Commission Panel has thoroughly reviewed the voluminous written and oral evidence presented during the Inquiry. The views of the Commission Panel and the conclusions drawn from the evidence are documented in this Report and form the basis for the recommendations that follow.

5.1 Term of Reference #3: The Heritage Contract

Recommendation #1

That the Heritage Contract attached as Appendix B be legislated as contemplated in the Energy Plan.

Recommendation #2

That the start date of the Heritage Contract should be April 1, 2004.

Recommendation #3

That the Heritage Contract have a ten-year term with provision for automatic annual renewal, subject to termination at the end of the ten-year term by a Government directive.

Recommendation #4

That the Heritage Contract provide that the Commission may modify the Heritage Payment Obligation to accommodate Performance-Based Ratemaking or any other determinations of the Commission.

Recommendation #5

That the British Columbia Transmission Corporation ("BCTC") be the sole supplier of transmission and ancillary services that can be provided from the assets of BC Hydro, except so far as such services may be self-supplied pursuant to a BCTC tariff or required for the transactions contemplated in the Transfer Pricing Agreement.

Recommendation #6

That the Commission allocate the benefits of the Heritage Resources among customer classes as part of its ratemaking jurisdiction pursuant to the Utilities Commission Act.

Recommendation #7

That Special Direction No. 8 be amended such that the Commission may review projects that may derive material benefits arising from the Heritage Resources to determine whether the project or projects should be included as Heritage Resources in the Heritage Contract. Further, that Special Direction No. 8 be amended to allow the Commission to revise the definition of Heritage Energy or Heritage Payment Obligation in the Heritage Contract if it is satisfied that a material change in circumstances has permanently affected the capability of the Heritage Resources or of BC Hydro's cost of generating the heritage energy.

5.2 Term of Reference #4: Transmission Voltage Customers and Generation Access

Recommendation #8

That stepped rates be implemented according to the principles and considerations set forth in Chapter 3. The principles are repeated below for convenience:

- the Tier 2 rate should reflect the long-term opportunity cost of new supply, where long-term is understood to include the acquisition cost required to obtain that supply;
- the quantity of power being sold to industrial customers at Tier 1 of the stepped rate should be initially set at 90 percent, and the Tier 2 quantity should make up the remaining 10 percent (the Tier1/Tier 2 Split); and
- the Tier 1 rate should be derived from the Tier 2 rate and the Tier1/Tier2 Split to achieve, to the extent reasonably possible, revenue neutrality.

Recommendation #9

That a report be submitted to the Government of a three year review of the impacts of the stepped rates, including customers' demand response and the percentage of customers' load served by third party suppliers.

Recommendation #10

That prior to the completion of the rate design hearing the initial determination of the stepped rates and time-of-use rates be based on the same revenue requirement used for determination of the Rate Schedule 1821 rates.

Recommendation #11

That load aggregation within a multiplant ownership be allowed so long as it is restricted to operating units.

Recommendation #12

That the Customer Baseline Load ("CBL") used for applying stepped rates to industrial customers should be based on past experience adjusted for anomalies and reviewed annually. Further, that the Commission will continue to approve CBLs and to resolve disputes as necessary.

Recommendation #13

That time-of-use rates should be implemented at the same time as stepped rates.

Recommendation #14

That industrial and large commercial customers eligible for BC Hydro's Rate Schedule 1821 be required, at their election, to take service from BC Hydro from either the stepped rate or the time-of-use rate. Rate Schedule 1821 would be terminated.

Recommendation #15

That Aquila, New Westminster and UBC, as entities that distribute all or a significant portion of their load to others, be exempted from the application of stepped rates at this time and form a new rate schedule(s).

Recommendation #16

That BC Hydro's targeted PowerSmart and Customer Based Generation programs should be continued at funding levels justified on the basis of the Tier 2 rate, and that the programs be reviewed with the changes required for retail access for large power consumers.

5.3 Term of Reference #8: Legislation, Regulation and Special Directions

Recommendation #17

That the Government revise Special Directive No. 4 as set out in Appendix C

Recommendation #18

That the Government revise Special Direction No. 8 as set out in Appendix D

Recommendation #19

That Special Direction No. 8 be revised to establish a Heritage Deferral Account to become effective on the same date as the Heritage Contract and that any balance in the Rate Stabilization Account ("RSA") should be transferred to the Heritage Deferral Account.

Recommendation #20

That the Government review Special Direction No. 8 and Special Directive No. 4 regarding the definition of equity and deferred credits to determine if a revised Special Direction is required.

Recommendation #21

That Powerex file an application with the Commission for approval of an incentive mechanism that provides for an incentive to Powerex related to its trading activities prior to April 1, 2005. Such an incentive mechanism may provide for sharing of the amount set out in subparagraph 3(h)(ii) of the Terms of Reference, provided that the amount eligible to be shared by Powerex does not exceed $20 million.

Recommendation #22

That the appropriate level of regulatory oversight by the Commission of Powerex be limited to the review of the income statement of Powerex. That the Commission review the extent of the appropriate regulatory oversight of Powerex when, and if, an incentive mechanism for Powerex is approved.

5.4 Scheduling

The Inquiry addressed the schedule of certain future applications. The response of participants to the issue of the scheduling of proceedings was based on their views about the orderly sequencing of applications and their beliefs of what level of detail would be needed to successfully initiate stepped rates and transmission access.

BC Hydro and Intervenors representing distribution voltage customers generally preferred a mid-2005 effective date to complete the BC Hydro and BCTC revenue requirements and rate design hearings prior to establishing stepped rates and retail access (T11: 2316). The large commercial and industrial customers preferred a 2004 effective date (CEC Final Argument, p. 81; JIESC Final Argument, p. 37). The IPPBC preferred a 2004 effective date, but with conditions that were related to practical considerations of third party supply to serve transmission voltage customers.

Together, the following sections recommend a schedule that should accomplish full implementation of the Policy Actions related to stepped rates and retail access for industrial consumers prior to the end of 2004.

BC Hydro Revenue Requirement Scheduling

BC Hydro stated that it will be making a Revenue Requirements application for approval of interim rates effective April 1, 2004. This would require BC Hydro to file its Revenue Requirements application by March 1, 2004. BC Hydro contends that it is impossible to file its Revenue Requirements application concurrently with its rate design application (T11: 2338), a position the Commission Panel accepts. The Commission Panel notes that a later filing date of the rate design application would not delay the implementation of the Energy Plan.

Recommendation #23

That the Government accept a filing date for the BC Hydro revenue requirement application that is no later than March 1, 2004.

BCTC Rate Filing Scheduling

BC Hydro submits that retail access on an interim basis could be accommodated without any changes to the WTS. BC Hydro notes that transmission services would be the subject of a 2004 filing by BCTC. BC Hydro proposes that the terms and conditions of transmission services required for retail access could be deferred to the 2004 BCTC proceeding, at which time BCTC will have been able to consider fully the issues relevant to its tariffs and retail access. BCTC committed to filing a tariff providing for access to transmission voltage customers sufficiently early in 2004 to permit access by the end of 2004 (T11: 2325). A filing date of June 1, 2004, although possibly preferred by BCTC, could be expected to delay retail access to April 1, 2005.

Policy Actions #15 and #16 relate to the rates to be approved for the BCTC. Pursuant to section 4(1) of the TCA:

> The transmission corporation must, on or before December 31, 2004 or such other date as the Lieutenant Governor in Council may prescribe, seek an order from the commission approving the transmission corporation's first schedule of rates for transmission service to be provided by the transmission corporation.

In the absence of an LGIC Order prescribing a date earlier than December 31, 2004, the reference dates in the Energy Plan and the TCA need to be reconciled. The TCA date was set after the Energy Plan was released; therefore, it may follow that the later date has superseded the earlier date. If the TCA date is the filing date of the BCTC application then an effective date for retail access can be reasonably forecast to be the fourth quarter of 2005. During the proceeding, BCTC said it would endeavour to file an application by the end of the second quarter of 2004, maybe as early as March or April 2004 (BC Hydro Final Argument, p. 37).

Recommendation #24

That an LGIC Order be issued, pursuant to section 4(1) of the Transmission Corporation Act, prescribing a date of March 1, 2004 if retail access is to be implemented prior to 2005.

Stepped Rates and Retail Access Scheduling

The Commission Panel recognizes that the success of retail access is largely dependent on the success of stepped rates. Retail access requires both an approved BCTC tariff, which provides for access to transmission voltage customers, and approved generation access principles, which establish the terms for transmission voltage customers to take third party supply.

The Commission Panel finds that very limited benefits can be expected to be derived from retail access prior to determinations related to access to transmission, which will be the subject of the BCTC application. For reasons stated below, the Commission Panel finds that the earliest practicable date for implementing retail access is the end of 2004.

BC Hydro believes that it would be premature to design generation access principles before the BCTC tariffs and the stepped rate design are known (Ex. 8-2, p. 10). Provided that the principles for stepped rates are established by reply of the Government to the Commission Panel's recommendations and that the BCTC tariffs are filed pursuant to the recommendation above, the Commission Panel concludes that BC Hydro can apply for the stepped rates, time-of-use rates, and generation access principles as part of the same filing and be approved by December 31, 2004.

The current ratemaking provisions of the UCA provide the Commission with the necessary jurisdiction to approve stepped rates. Given this jurisdiction, if the Government accepts the Commission Panel's recommendations on stepped rates, no further direction from the Government is required. The Commission would then proceed with the implementation of stepped rates.

The Commission Panel concludes that stepped rates, time-of-use rates and generation access principles should have the same effective date, so that transmission voltage customers can assess the full range of choice to be afforded to them.

Recommendation #25

That BC Hydro file an application, within 30 days of the Commission Decision in the BCTC tariff filing pursuant to section 4(1) of the Transmission Corporation Act, seeking approval for stepped rates, time-of-use rates and generation access principles, and PowerSmart and Customer Based Generation programs.

Rate Design Scheduling

BC Hydro has not changed its rate design since 1992. Undertaking a full rate design study after such a long period will require significant effort by BC Hydro, especially given the separation of Generation, Transmission, and Distribution, and the extended period of the rate freeze. It is reasonable to expect that there will be significant changes to BC Hydro's bundled rates, including changes to the allocation by customer class of the revenue requirement and to the billing determinants for each customer class.

BC Hydro contends that the BCTC transmission rates and the BC Hydro revenue requirements have implications for the design of BC Hydro's bundled rates (T11: 2341-2342). Therefore, both matters should be approved prior to the filing of the rate design application. The Commission Panel concludes that the filing of the rate design application should be delayed until late 2004 or early 2005, so that stepped rates and retail access tariffs can be approved prior to the end of 2004.

Recommendation #26

That BC Hydro file a rate design application prior to April 1, 2005.

Table 2: Anticipated Timeline of Future Filings

	2004				2005			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
BC Hydro Revenue Requirements								
BCTC: Transmission Access								
Stepped Rates, TOU Rates, Generation Access								
Rate Design								

5.5 Other Matters

<u>Recommendation #27</u>

That the determination of Generation Related Transmission Assets ("GRTAs") for the BC Hydro Wholesale Transmission Service rates, be accepted for the purposes of the BCTC tariff filing to be made pursuant to section 4(1) of the TCA, and that functionalization of GRTAs otherwise continue to be within the jurisdiction of the Commission.

Dated at the City of Vancouver, in the Province of British Columbia, this 16th day of October 2003.

Original signed by:
Robert H. Hobbs
Chair

Original signed by:
Kenneth L. Hall
Commissioner

Original signed by:
Paul G. Bradley
Commissioner

APPENDIX A – TERMS OF REFERENCE

See attachment.

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 0253 *, Approved and Ordered* MAR 25 2003

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that pursuant to section 5 of the *Utilities Commission Act,* the Lieutenant Governor in Council requests the British Columbia Utilities Commission to provide recommendations relating to the matter of a heritage contract and other electricity policy matters as specified in the Terms of Reference attached as Schedule A to this Order.

Minister of Energy and Mines

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section:- *Utilities Commission Act, s. 5*

Other (specify):-

March 11, 2003

341 /2003/16

SCHEDULE A

TERMS OF REFERENCE

IN THE MATTER OF the Utilities Commission Act ("the *Act*")

and

IN THE MATTER OF Recommendations Relating to a Heritage Contract for BC Hydro's Existing Generation Resources, and to Stepped Rates and Transmission Access

WHEREAS, under Section 5(1) of the *Act*, the Lieutenant Governor in Council ("LGIC") may request the BC Utilities Commission ("BCUC" or "Commission") to provide advice on any matter the LGIC specifies; and

WHEREAS on November 25, 2002, the Province of British Columbia announced its new Energy Plan, the four cornerstones of which are: low electricity rates and public ownership of BC Hydro; secure and reliable energy supply; more private sector opportunities; and environmental responsibility and no nuclear power sources; and

WHEREAS the Energy Plan outlines several 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 #5 that the Commission will once again regulate the rates charged by BC Hydro; and

WHEREAS the Energy Plan contemplates that the Commission should conduct an inquiry to develop and refine certain policy areas relating to regulation of BC Hydro prior to the commencement of its review of BC Hydro's rates and should submit a report to government describing changes to legislation and regulations that it believes are desirable in that connection; and

WHEREAS the Energy Plan contemplates a full review of BC Hydro's rate levels based on an application to be filed before March 31, 2004; 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 its distribution line of business for a term of ten years initially; and

WHEREAS the Energy Plan provides in Policy Action #2 that an appropriate level of trade revenues, net of incremental costs properly allocated by BC Hydro for internal management purposes, will continue to be assigned for rate-setting purposes to help maintain low and stable rates for BC consumers; and

WHEREAS trade revenues, net of incremental costs properly allocated by BC Hydro for internal management purposes, above $200 Million in any year will flow to the government for the benefit of all British Columbians; and

WHEREAS the Energy Plan contemplates large industrial or transmission rate customers and energy suppliers having access to transmission for the purpose of acquiring and providing energy for all or a portion of their needs based on principles to be established; and

WHEREAS the Energy Plan provides in Policy Direction #21 that new rate structures should be developed to send better price signals to large electricity consumers.

NOW THEREFORE the Commission shall conduct an inquiry pursuant to Section 5 of the *Act* in compliance with the following Terms of Reference:

1. The general purpose of the inquiry is to obtain the Commission's Recommendations on what changes, if any, should be made to legislation, regulations, special directions or special directives affecting BC Hydro and/or the Commission in order to implement the Energy Plan in connection with the issues identified in paragraphs 3 and 4 of these Terms of Reference.

   For greater certainty, the Commission shall provide Recommendations on whether the current rate stabilization account provided for in Special Direction 8 and Special Directive 4 should be eliminated and, if so, whether any alternative form of deferral account mechanism should be considered to implement the Commission's Recommendations with respect to paragraph 3 of the Terms of Reference, and on whether there is a need for revisions to paragraph 3 of Special Direction 8 to implement the Commission's Recommendations with respect to paragraph 4 of the Terms of Reference.

2. With respect to Policy Action #1 from the Energy Plan, the Commission shall make Recommendations concerning the terms and conditions which should be contained in a Heritage Contract based on the following assumptions:

   (a) The resources and obligations to which the Heritage Contract shall relate are those set out in Schedule A;

   (b) The classes of customers that are eligible to benefit from the Heritage Contract are those set out in Schedule B, as may be amended from time to time to reflect the introduction of new rate structures or options;

   (c) Except as expressly provided herein, the determination of rates for customers identified in Schedule B will not be considered until after the Commission's Recommendations have been provided to the Lieutenant Governor in Council pursuant to these Terms of Reference; and

   (d) The quantity of energy producible from the resources shall be determined assuming average water conditions for the duration of the Heritage Contract.

3. The Commission shall make specific Recommendations relating to the following matters concerning the Heritage Contract:

(a) The quantity of energy which will be available under the Heritage Contract;

(b) The cost of supplying the energy identified in subparagraph (a), including:

(i) All costs properly allocated to that activity by BC Hydro for internal management purposes;

(ii) An allowance for return on BC Hydro's equity invested in the assets identified in Schedule A; and

(iii) The portion, if any, of transmission assets that should be deemed to be "generation related" and which should be included in the heritage contract for costing purposes, and ultimately to be recovered in electricity rates of BC Hydro's distribution line of business;

(c) The price that BC Hydro's distribution line of business should be deemed to pay for the quantity of energy identified in subparagraph (a);

(d) Having regard for the considerations referred to in 3(h) below, the provisions that should be included in the Heritage Contract relating to capacity, shape, and scheduling flexibility to fairly allocate the benefits arising from the resources listed in Schedule A under average water arising from the resources listed in Schedule under average water conditions between the customers listed in Schedule B and BC Hydro;

(e) The principles and impacts of providing ancillary services requirements to BC Transmission Corporation;

(f) The extent to which the quantity, price or other terms or conditions relating to the acquisition of the heritage energy by the distribution line of business should vary during the initial ten-year term of the Heritage Contract:

(i) by reason of changed circumstance;

(ii) by reason of a determination that the allocation identified in subparagraph (b) is not appropriate;

(iii) by reason of capital maintenance or similar investments not intended to materially affect the productive capacity of the assets listed in Schedule A; and;

(iv) by reason of any other factor the Commission believes is important;

(g) The renewal provisions which should apply to the continuation of the Heritage Contract after the expiry of an initial ten-year term;

(h) The appropriate regulatory framework:

(i) which provides incentives to, and allows, BC Hydro and its affiliates and subsidiaries to make timely decisions to maximize trade revenues net of costs properly allocated by BC Hydro for internal management purposes in light of the determinations made pursuant to subparagraph (d); and

(ii) to allocate amounts of trade revenue, net of incremental costs properly allocated by BC Hydro for internal management purposes, up to a maximum of $200 million per year, between BC Hydro and customers listed in Schedule B in a manner that provides rewards to the party that takes the risk associated with realizing those rewards while minimizing the expenses and delays associated with regulatory oversight of activities relating to trade;

(i) The determination of the state date of the Heritage Contract including potential adjustments at the start of the Heritage Contract relating to capacity, shape and scheduling flexibility.

4. The Commission shall make specific Recommendations relating to any changes it believes are desirable in the rates of transmission voltage customers to accomplish the objectives set out in the Energy Plan, including:

(a) The terms and conditions that should govern existing and new large industrial or transmission rate customers' access to transmission for the purpose of acquiring power from other energy suppliers' generation;

(b) The detailed provisions of new stepped rate schedules as more fully described in the Energy Plan, including load aggregation by a customer with facilities at more than one location; and

(c) The principles which should govern the terms and conditions under which large industrial or transmission rate customers wishing to obtain generation from alternate suppliers may decline to obtain service from BC Hydro or may apply to obtain service from BC Hydro thereafter.

5. For the purpose of conducting this inquiry and obtaining stakeholder input, the Commission may seek and employ expert advice on various subjects and shall employ any or all of the powers provided to it under the *Act* and, in particular, may, in its sole discretion, employ diverse procedures to resolve specific issues within the Terms of Reference, including, as appropriate, workshops, mediation, dispute resolution mechanisms, pre-hearing conferences, and oral and written public hearings.

6. The Commission shall require BC Hydro to file by April 30, 2003 a proposal that identifies the detailed Recommendations and reasons that BC Hydro believes should be contained in the Commission's report to the Lieutenant Governor in Council.

7. The Commission shall invite comment on BC Hydro's proposal from all affected stakeholders and identify appropriate processes to consider it in compliance with paragraph 5.

8. The Commission shall submit a report to the Lieutenant Governor in Council by no later than October 17, 2003, listing its Recommendations and the reasons for the Recommendations, including proposed legislation, regulations, special directions to the Commission or special directives to BC Hydro, as it thinks fit.

9. The Commission shall consider any other matters that may be specified in supplementary Terms of Reference issued by the Lieutenant Governor in Council pursuant to Section 5 of the *Act*.

March 7, 2003

SCHEDULE A
BC Hydro's Existing Facilities

Resources

(a) Electric Facilities

Aberfeldie
Alouette
Ash River
Bridge River
Buntzen/Coquitlam
Cheakamus
Clowhom
Duncan
Elko
Falls River
G.M. Shrum
Hugh Keenleyside Dam (Arrow Reservoir)
John Hart
Jordan
Kootenay Canal
Ladore
La Joie
Mica
Peace Canyon
Puntledge
Revelstoke
Ruskin
Seton
Seven Mile
Shuswap
Spillimacheen
Stave Falls
Strathcona
Wahleach
Walter Hardman
Whatshan

(b) Thermal Facilities

Burrard Thermal
Fort Nelson
Prince Rupert

Other Rights and Obligations

Columbia River Treaty and Entity Agreements made thereunder
Skagit Valley Treaty
Canal Plant Agreement
Keenleyside Entitlement Agreement
Replacement Electricity Supply Agreement between the Province and Alcan
Power for Jobs

SCHEDULE B

Residential Service	General Service	Irrigation Service	Street Lighting Service	Transmission Service
1101	1200	1401	1701	1821
1103	1201		1702	1848
1105	1205		1703	1852
1107	1206		1704	3808
1111	1207		1755	TS #1
1113	1210		1761	
1117	1211		1770	
1121	1220			
1123	1222			
1127	1223			
1131	1233			
1132	1234			
1133	1241			
1134	1242			
1135	1243			
1137	1244			
1148	1255			
	1256			
	1265			
	1266			
	1277			
	1278			
	1288			

APPENDIX B – HERITAGE CONTRACT[2]

WHEREAS on November 25, 2002, the Province of British Columbia released Energy for Our Future, A Plan for B.C. (the "Energy Plan"); ~~announced its new 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 agree as follows.

Definitions

1. In this Agreement:

(a) "Agreement" means this Heritage Contract including Schedule A;

(b) "Ancillary Service Requirements" means services necessary to deliver energy;

(c) "BC Hydro" means the British Columbia Hydro and Power Authority;

~~(b) "Commission" means the British Columbia Utilities Commission;~~

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

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

(f) "Commission" means the British Columbia Utilities Commission;

(g) "Heritage Electricity" means the capacity, energy and ancillary services that BCH Generation is required to supply to BCH Distribution under this Agreement;

(h) "Heritage Energy" means the annual amount of energy delivered from the Heritage Resources (49,000 GWh under average water conditions), less the energy delivered under the Skagit Valley Treaty, as may be adjusted from time to time in accordance with Section 8;

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[2] The blacklining in this draft Heritage Contract shows changes from BC Hydro's proposed Heritage Contract. It is intended to reflect major changes to assist the reader. Minor changes are not blacklined.

(i) “Heritage Payment Obligation” means the annual payment determined in accordance with the procedure set out in Schedule A to this Agreement, as may be adjusted from time to time in accordance with Section 8;

(j) “Heritage Resources” means the Electric Facilities and Thermal Facilities prescribed in Schedule A to the Terms of Reference, together with the related civil works and plant;

~~(i) “Agreement” means this Heritage Contract including Schedule A;~~

(k) "Order" means an order of the Commission;

(l) “Terms of Reference” means Schedule A, Terms of Reference, to British Columbia Order-in-Council No. 0253, Approved and Ordered March 25, 2003;

(m) "Transfer Pricing Agreement" means the Transfer Pricing Agreement for Electricity and Gas dated April 1, 2003 between BC Hydro and Powerex Corporation; and

(n) “Year” means fiscal year.

Electricity Supply

2. BCH Generation will provide the full capacity of the Heritage Resources to BCH Distribution on a priority call basis.

3. BCH Generation will supply up to the Heritage Energy to BCH Distribution, as required by BCH Distribution.

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.

5. BCH Distribution will be responsible for obtaining transmission services.

Ancillary Services

6. BCH Distribution may use the capacity available to it under Section 2 to ~~either~~ deliver energy to meet customer demand ~~or~~ and to satisfy its Ancillary Service Requirements.

Payment

7. On an annual basis, BCH Distribution will pay BCH Generation an amount equal to the Heritage Payment Obligation.

Adjustment

8. The parties acknowledge that the Commission may by Order modify this Agreement, including the Heritage Energy or Heritage Payment Obligation and any such modification will automatically modify this Agreement, the Heritage Energy or 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. In the spirit of coordinated operation of the BC Hydro system, the parties will make reasonable efforts to resolve disputes arising in relation to this Agreement at the staff level through implementation planning, cooperation and consultation. Issues will be elevated to more senior management levels within each party as needed to achieve timely resolution.

Term and Termination

11. This Agreement shall commence on April 1, 2004 for a term (the "Term") of 10 years ending on March 31, 2014. The Term will be extended for an additional period of 12 months, each succeeding April 1, subject to a directive of the provincial government on or before April 1, 2005 or on or before any succeeding April 1, terminating the Agreement on 10 years' notice.

Dated this ____ day of ________, 2004.

___________________________	___________________________
BC Hydro Distribution	BC Hydro Generation

SCHEDULE A

HERITAGE PAYMENT OBLIGATION

The Heritage Payment Obligation is the sum of the following cost and revenue components related to the Heritage Resources actually incurred by BCH Generation in a Year and approved or determined by Order of the Commission, for inclusion in the Heritage Payment Obligation:

(i) cost of energy: the cost of water fees and energy purchases (gas and electricity) required to supply Heritage Electricity;

(ii) operating costs: all costs of operating and maintaining the Heritage Resources, including an allocation of corporate costs;

(iii) asset related expenses: the costs of owning the Heritage Resources including depreciation, interest, finance charges and other asset related expenses;

(iv) generation-related transmission assets: all costs or payments related to any generation-related transmission required by the Heritage Resources;

(v) return on equity: the applicable return on equity, currently based on Special Direction No. 8, on investments in Heritage Resources;

less,

(vi) other revenues: any revenues BCH Generation receives from other services provided from the Heritage Resources including revenues related to Skagit Valley Treaty obligations, revenues from provision of ancillary services to the transmission operator in respect of third party use of the transmission system, revenues from sales of surplus hydro energy pursuant to section 5 of the Transfer Pricing Agreement, and other miscellaneous revenues.

APPENDIX C – SPECIAL DIRECTIVE NO. 4[3]

Special Directive No. 4 to the British Columbia Hydro and Power Authority:
Revised to Effect (in part) BC Hydro's Heritage Contract Proposal

Application

1. This Special Directive is issued by the Lieutenant Governor in Council to the British Columbia Hydro and Power Authority ("BC Hydro") under authority of section 35 of the Hydro and Power Authority Act (the "Act") as it pertains to annual payments to the provincial government of an amount specified in this Special Directive.

Return on Public Investment

2. For the purpose of this Special Directive only, the following definitions shall apply:

   "Commission" means the British Columbia Utilities Commission constituted under the *Utilities Commission Act*;

   "debt" means the sum of revolving borrowings, bonds, notes and debentures, net of related sinking funds, temporary investments, term debentures receivable and repurchased debt, at the end of the financial year;

   "distributable surplus" means consolidated net income from all sources including electricity trade income as computed by BC Hydro according to generally accepted accounting principles and confirmed by BC Hydro's external auditors,

   (a) ~~after any rate stabilization account transfers pursuant to paragraph 3 and 4 and~~ before any deduction for any amounts paid or payable in accordance with a directive issued under section 35 of the ~~Hydro Power and Authority~~ Act; and

   (b) less interest during construction adjusted for depreciation to prevent double counting;

   ~~"equity" means the sum of retained earnings and deferred credits, at the end of the financial year;~~

[3] The blacklining in this Special Directive No. 4 shows changes from the original. It is intended to reflect major changes to assist the reader. Minor changes are not blacklined.

"deferred credits" means the sum of ~~the rate stabilization account~~ deferred revenue, contributions arising from the Columbia River Treaty and contributions in aid of construction at the end of the financial year;

"equity" means the sum of retained earnings and deferred credits, at the end of the financial year.

~~3. If the consolidated net income, before any rate stabilization account transfers, is less than the amount needed by BC Hydro to achieve an annual rate of return on equity pursuant to Special Directive No. 8 to the Commission, then the consolidated net income shall be increased accordingly by an appropriate transfer from the rate stabilization account, provided,~~

~~(a) there is a positive balance in the rate stabilization before the transfer, there is a zero or positive balance in the rate stabilization account after the transfer, and the debt/equity ratio of BC Hydro after the transfer is not greater than 80:20;~~

~~4. If the consolidated net income, before any rate stabilization account transfers, is greater than the amount needed by BC Hydro to achieve an annual rate of return on equity pursuant to Special Directive No. 8 to the Commission, then the consolidated net income shall be decreased accordingly by an appropriate transfer to the rate stabilization account;~~

3. On or before June 30 of each year, the BC Hydro Board of Directors shall confirm a payment to the provincial government (the "payment") for the previous financial year as determined below.

4. The payment shall equal 85 percent of the distributable surplus for the financial year provided the debt/equity ratio of BC Hydro after deducting the payment is not greater than 80:20. If the payment would result in the debt/equity ratio exceeding 80:20, then the payment shall be reduced to the extent necessary to maintain the debt/equity ratio at 80:20 after deducting the payment.

5. The payment determined by paragraph 4 shall be paid into the provincial government's consolidated revenue fund by no later than June 30 each year.

6. The Special Directive is effective for the financial year ending March 31, 2000, and all subsequent financial years.

Revocation of Special Directive No. 2

7. The Special Directive revokes and replaces Special Directive No. 2 dated November 13, 1992.

APPENDIX D – SPECIAL DIRECTION NO. 8[4]

Special Direction No. 8 to the British Columbia Utilities Commission: Revised to Effect (in part) BC Hydro's Heritage Contract Proposal

1. In this Special Direction:

"Act" means the *Utilities Commission Act*;

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

"Commission" means the British Columbia Utilities Commission;

"debt" means the sum of revolving borrowings, bonds, notes and debentures, net of related sinking funds, temporary investments, term debentures receivable and repurchased debt, at the end of the financial year;

"deferred credits" means the sum of deferred revenue, contributions arising from the Columbia River Treaty and contributions in aid of construction at the end of the financial year;

"equity" means the sum of retained earnings and deferred credits, at the end of the financial year;

"government policy directive" means a directive in writing to BC Hydro from the minister charged with the administration of the *Hydro and Power Authority Act*;

"heritage contract" means the document attached as Appendix A to this Special Direction;

"heritage deferral account" means the accounting mechanism established pursuant to paragraph 5.1;

"heritage energy" means the amount of energy defined in the heritage contract;

"heritage payment obligation" means the payment amount defined in the heritage contract;

"heritage resources" means the facilities defined in the heritage contract;

"total invested capital" means debt plus equity, at the end of the financial year;

[4] The blacklining in this Special Direction No. 8 shows changes from the original. It is intended to reflect major changes to assist the reader. Minor changes are not blacklined.

"trade income" means the audited net income of Powerex Corporation, according to generally accepted accounting principles unless otherwise determined by the Commission, adjusted by:

(a) where audited net income is less than zero, adding the amount necessary to make it zero; and

(b) where audited net income is greater than $200 million, subtracting any amounts in excess of $200 million.

2. This Special Direction is issued to the Commission under section 3 of the *Utilities Commission Act*.

3. In designing BC Hydro electricity rates, the Commission shall ensure that those rates contribute to conservation and efficient electricity use by reflecting the total cost of new sources of electricity 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.

3.1 Notwithstanding paragraph 3, in designing electricity rates for BC Hydro's industrial and large commercial customers, the Commission shall ensure that those rates are stepped rates and time-of-use rates consistent with the policy of the provincial government following recommendations contained in the Commission's report to the Lieutenant Governor in Council dated October 17, 2003.

4. Subject to paragraph 5.2, in determining whether the rates of BC Hydro are sufficient to yield a fair and reasonable compensation for the services provided by it, or a fair and reasonable return on the appraised value of its property, the Commission must ensure the rates permit BC Hydro to collect sufficient revenues in each financial year to:

(a) sustain an operating and capital regime that continues to provide a quality and reliable electricity service;

(b) meet other expenses reasonably incurred in accordance with government policy directives including, but not limited to,

(i) directives for the construction or operation of a plant or system, or an extension to either of them, by BC Hydro, and

(ii) directives that BC Hydro enter into contracts;

(c) meet all debt service, tax and other financial obligations; and

(d) achieve an annual rate of return on equity equal to that allowed on a pre-income tax basis by the most comparable investor-owned energy utility regulated under the Act.

4.1 In assessing BC Hydro's rates pursuant to paragraph 4 the Commission shall, with respect to determining forecast cost of energy:

(a) treat the heritage contract as if it were a legally binding agreement between two arms-length parties; and

(b) determine the cost of energy required by BC Hydro to meet its domestic service obligations in excess of the energy supplied under the heritage contract on a cost-of-service basis, subject to any mechanism, formula or method employed by the Commission in setting BC Hydro's rates pursuant to section 60 (b.1) of the Act.

4.2 On application by BC Hydro or any other interested party, the Commission may revise the definition of "Heritage Energy" or "Heritage Payment Obligation" in the heritage contract, in accordance with section 8 of the heritage contract, if the Commission is satisfied that a change in circumstances has permanently affected the capability of the heritage resources or BC Hydro's cost of generating the heritage energy.

4.3 On application by BC Hydro or any other interested party, the Commission may revise the definition of "Heritage Resource" in the heritage contract, if the Commission is satisfied that a capital addition or a capital extension is intended to derive material benefits from heritage resources. The Commission may order a revision to the amount of the heritage energy and heritage payment obligation for the incremental power output, or any portion thereof, of a capital addition or a capital extension.

5. The return on equity in paragraph 4 (d) must be calculated using forecast consolidated operating income from all sources, including a forecast of trade income.

~~where projections of consolidated net income include an amount of electricity trade income consistent with the Commission's forecast of annual net export revenue under average water conditions, as contained in the Commission's report to the Lieutenant Governor in Council dated June 30, 1992, as amended on BC Hydro's Energy Removal Certificate application, and~~

~~where projected consolidated net income, before any rate stabilization account transfers, is less than the amount needed by BC Hydro to achieve an annual rate of return on equity pursuant to paragraph 4 (d), an allowance for an appropriate transfer from the rate stabilization account provided~~

~~(i) there is projected to be a positive balance in the rate stabilization account before the transfer,~~

~~(ii) there is projected to be a zero or positive balance in the rate stabilization account after the transfer, and~~

~~(ii) the debt/equity ratio of BC Hydro and after the transfer is not greater than 80:20.~~

5.1 The Commission shall establish the heritage deferral account for the purpose of recording any differences between forecasts of the heritage payment obligation and the heritage payment obligation, and any differences between forecasts of trade income and trade income.

5.2 (a) If there is a positive balance in the heritage deferral account when the Commission is assessing BC Hydro's rates pursuant to paragraph 4, the Commission may reduce the amount otherwise determined pursuant to paragraph 4 by an amount less than or equal to the balance of the heritage deferral account. When there are reductions pursuant to paragraph 4, the heritage deferral account shall be debited by an equal amount.

(b) If there is a negative balance in the heritage deferral account when the Commission is assessing BC Hydro's rates pursuant to paragraph 4, the Commission may increase the amount otherwise determined pursuant to paragraph 4 by an amount no greater than the absolute value of the balance of the heritage deferral account. When there are increases pursuant to paragraph 4, the heritage deferral account shall be credited by an equal amount.

6. Notwithstanding paragraph 4 (d), in setting BC Hydro electricity rates, the Commission shall ensure that rates are smooth, stable and predictable.

6.1 Smooth, stable and predictable rates for the purpose of setting BC Hydro electricity rates means that, with the exception of pass through items pursuant to section 61 (4) of the Act, general electricity rate increases shall not exceed 1 percentage point above the rate of inflation for the remainder of the 1992/93 financial year and shall not exceed 2 percentage points above the projected rate of inflation on a year over year basis thereafter.

6.2 For the purpose of implementing rate design or of closing rates, individual electricity rate increases may exceed the limits set out in paragraph 6.1.

6.3 The rate of inflation in paragraph 6.1 means the change in the average level of the British Columbia consumer price index during the most recent three month period for which published statistics are available prior to BC Hydro's rate application filing, compared to the average level of the British Columbia consumer price index during the same three month period a year earlier, and published statistics shall mean those published by Statistics Canada.

6.4 The projected rate of inflation in paragraph 6.1 means the provincial Ministry of Finance and Corporate Relations' latest available forecast published prior to BC Hydro's rate application filing of future year over year changes in the average level of the British Columbia consumer price index.

7. In setting BC Hydro electricity rates the Commission shall ensure that rates are fair, just and reasonable.

7.1 Repealed.

8. Electricity rates set by the Commission in accordance with this Special Direction may generate annual distributable surpluses for BC Hydro. These surpluses shall only be calculated and allocated in a manner specified by the Lieutenant Governor in Council pursuant to section 35 of the *Hydro and Power Authority Act* .

9. Repealed.

APPENDIX E – APPEARANCES

G.A. FULTON H. CRAIG	British Columbia Utilities Commission, Counsel
C. SANDERSON, Q.C. J. CHRISTIAN I. WEBB	British Columbia Hydro and Power Authority
R.B. WALLACE	Joint Industry Steering Committee
C. WEAFER	B.C. Greenhouse Growers Association, Commercial Class Energy Customers of British Columbia Hydro and Power Authority, United Flower Growers Cooperative Association
P.J. LANDRY	CBT Energy Inc.
D. AUSTIN	Independent Power Association of British Columbia
R. GATHERCOLE S. KHAN	British Columbia Old Age Pensioners' Organization Council of Senior Citizens' Organizations, Federated Anti-poverty Groups of BC, Senior Citizens' Association of BC, End Legislated Poverty, West End Seniors' Network, Tenants Rights Action Coalition ("British Columbia Old Age Pensioners' Organization *et al*")
M. METCALFE	Office and Professional Employees' International Union, Local 378, B.C. Citizens for Public Power
C. BOIS	Aquila Networks Canada (British Columbia) Ltd., City of New Westminster, University of British Columbia
J.D.V. NEWLANDS	Elk Valley Coal Corporation
J. PEVERETT	British Columbia Transmission Corporation
J. TAYLOR	Leader Mining
A. WAIT	Self
I. MINTY	Self
R. CARLE	Interior Municipal Electrical Utilities

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British Columbia Hydro and Power Authority: Heritage Contract – Panel 2	KENNETH SPAFFORD CHRISTOPHER O'RILEY TONY MORRIS CAMERON LUSZTIG
British Columbia Hydro and Power Authority: Stepped Rates – Panel 3	CAMERON LUSZTIG COLIN FUSSELL
Independent Power Association of British Columbia – Panel	HARVIE CAMPBELL
CBT Energy Inc. – Panel	ZAK EL-RAMLY KENNETH EPP
The Joint Industry Electricity Steering Committee - Panel	GARY SALEBA DAN POTTS DAL SCOTT DENNIS FITZGERALD LLOYD GUENTHER
City of New Westminster, Aquila Networks Canada (British Columbia) Ltd. and the University of British Columbia – Panel	GORDON APPERLEY PENNY COCHRANE GEORGE ISHERWOOD

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APPENDIX H – LIST OF ACRONYMS AND ABBREVIATIONS

Act	Utilities Commission Act
Alberni-Clayoquot	Regional District of Alberni-Clayoquot
Aquila	Aquila Networks Canada (British Columbia) Ltd.
BC Hydro	British Columbia Hydro and Power Authority
BCCPP	BC Citizens for Public Power
BCOAPO	BC Old Age Pensioners' Organization *et al.*
BCTC	British Columbia Transmission Corporation
BCUC	British Columbia Utilities Commission
Burrard	BC Hydro's Burrard Thermal Generating Plant
CBG	Customer-Based Generation
CBL	Customer Baseline Load
CBTE	CBT Energy Inc.
CEC	Commercial Energy Consumers
City	City of New Westminster
Commission	British Columbia Utilities Commission
GRTA	Generation Related Transmission Assets
GWh	Gigawatt hours
HDA	Heritage Deferral Account
HPO	Heritage Payment Obligation
HSO	Heritage Supply Obligation
IMEU	Interior Municipal Electrical Utilities Group
IPP	Independent Power Producers
IPPBC	Independent Power Producers Association of BC
JIESC	Joint Industry Electricity Steering Committee
LGIC	Lieutenant Governor in Council
MWh	Megawatt hours
NCMA	North Central Municipal Association
New Westminster	City of New Westminster
NITS	Network Integration Transmission Service
PBR	Performance based ratemaking
PRRD	Peace River Regional District
PTP	Point-to-Point

ROE	Return on Equity
RSA	Rate Stabilization Account
SD4	Special Directive No. 4
SD8	Special Direction No. 8
TOU	Time-of-use
TCA	Transmission Corporation Act
TNRD	Thompson-Nicola Regional District
UBC	University of British Columbia
UCA	Utilities Commission Act
University	University of British Columbia
Utility	British Columbia Hydro and Power Authority
WTS	Wholesale Transmission Services

APPENDIX I – BC HYDRO DESCRIPTION OF THE TRANSFER PRICING AGREEMENT

The following description of the Transfer Pricing Agreement is extracted from BC Hydro's Final Argument at pages 10 through 12.

BC Hydro proposes to define Trade Income in Special Direction No. 8 as Powerex's audited net income, subject to a floor and ceiling of $0 and $200 million respectively.[1]

Powerex's audited net income will be calculated using generally accepted accounting principles as applied to transactions between Powerex and third parties, transactions between Powerex and BC Hydro, and associated transmission and other expenses. Transactions between Powerex and BC Hydro, including Powerex's use of the Trade Account, will be governed by the Transfer Pricing Agreement.[2]

There are three important elements of the Transfer Pricing Agreement that are relevant to BC Hydro's Heritage Contract proposal:

1. Sales of Surplus Hydro Electricity will accrue directly to the benefit of BC Hydro's ratepayers;
2. Point-to-point transmission costs incurred by BC Hydro in respect of Powerex's trading activities will be allocated against Powerex's net income; and
3. An appropriate cost of energy will be allocated to net electricity exports through the use of the Trade Account.

The first two provisions are important because they reduce the likelihood of the $200 million ceiling being reached. The third is important as it removes any inappropriate incentive that BC Hydro might have to draft reservoirs so as to increase net electricity exports in a particular year to increase Trade Income where it is otherwise close to $200 million. These elements are effected by the Transfer Pricing Agreement, through the following provisions.

Sections 5.1, 3.2.1, and 8.1.1 provide that if BC Hydro makes Surplus Hydro Electricity available to Powerex and a sale occurs, Powerex will pay to BC Hydro the Electricity Transfer Price for each MWh of Surplus Hydro

[1] Transcript vol. 5, p. 1114, line 21 to p. 1115, line 12 (O'Riley).

[2] Exhibit 43.

Electricity delivered to Powerex. The revenue received by BC Hydro from such sales directly offsets the Heritage Payment Obligation. The transfer appears as a cost to Powerex, reducing its net income.

Section 9.2 provides that Powerex shall pay to BC Hydro the point-to-point transmission costs incurred by BC Hydro for Powerex's trading activities, excluding sales of Surplus Hydro Electricity and certain other BC Hydro obligations. These costs reduce Powerex's net income.

Sections 6.1 and 6.2 provide that Powerex may sell to BC Hydro or purchase from BC Hydro electricity for trade purposes. Amounts sold to or purchased from BC Hydro for this reason are recorded in the Trade Account, which at any time may have a positive or negative balance.

Amounts sold to BC Hydro increase the balance of the Trade Account, and amounts purchased from BC Hydro decrease the balance of the Trade Account.[3]

The price Powerex pays for electricity purchased from BC Hydro is determined in Sections 8.2.1.2 and 8.2.2.1. Section 8.2.1.2 provides that if the Trade Account balance is positive, the price Powerex pays for net purchases (and which is debited from the Trade Account) is the weighted average cost of the electricity recorded in the Trade Account. Section 8.2.2.1 provides that if the Trade Account balance is negative the price Powerex pays for net purchases is the prevailing Electricity Transfer Price.[4] The effect of this distinction is to provide Powerex with a price signal that generally discourages it from taking the balance of the Trade Account negative unless market conditions objectively make it economic to do so. This also has the effect of discouraging Powerex from increasing net exports for the purpose of increasing Trade Income.

[3] It is important to bear in mind that the Transfer Pricing Agreement provides not only for transactions between Powerex and BC Hydro for trade purposes through the Trade Account, but also for BC Hydro to sell surplus hydroelectricity and to purchase electricity to meet its domestic needs. See Transcript vol. 5, p. 1115, line 18 to p. 1116, line 3 and vol. 4, p. 765, line 24 to p. 769, line 24 (O'Riley).

[4] The Electricity Transfer Price is described generally in Exhibit 8, section 3.3.4, as the Mid-Columbia index price plus the cost of transmission between Mid-Columbia and the BC border.