BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

British Columbia Hydro and Power Authority

WHOLESALE TRANSMISSION SERVICES

DECISION

April 23, 1998

Before:

Lorna R. Barr, Deputy Chair
Kenneth L. Hall, P.Eng., Commissioner
Paul G. Bradley, Commissioner

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1.0 INTRODUCTION

1.1 Background

British Columbia Hydro and Power Authority ("B.C. Hydro", "the Applicant", "the Utility") is a Provincial Crown Corporation whose mandate is to generate, transmit and distribute electricity in British Columbia. B.C. Hydro does so throughout British Columbia except for a few municipalities served by municipal utilities and in the Kootenay and South Okanagan areas which are served by West Kootenay Power Ltd. ("WKP"). B.C. Hydro operates under the *Hydro and Power Authority Act* and is subject to regulation by the British Columbia Utilities Commission ("the Commission", "the BCUC").

On November 10, 1995, B.C. Hydro filed an Application to provide Wholesale Transmission Services ("WTS"), including related ancillary services, within its service area. After a hearing, which took place in the spring of 1996, the Commission issued a Decision dated June 25, 1996 that approved a set of WTS tariffs for B.C. Hydro. However, in the 1996 Decision, the Commission stated that the approved tariffs required further analysis. In particular, the Commission stated that it was concerned with (1) the methodology used by B.C. Hydro to determine those assets whose costs are to be recovered in the transmission tariff and (2) the rate design method employed by B.C. Hydro. In response to the first concern, the Commission directed B.C. Hydro to file new rates, no later than January 1, 1997, based on a study which more precisely identified its transmission revenue requirement. In particular, the Commission directed that the new transmission revenue requirement should reflect the relative benefits which generation-related transmission assets provided to the generation and transmission functions, the extent to which 138 and 69 kV lines provide transmission benefits and the role of DSM with respect to transmission. In response to the second concern, the Commission directed that the rates based on the new transmission revenue requirement should reflect long-run marginal costs and locational considerations, while also being designed to collect the full revenue requirement. The January 1, 1997 filing date was later amended to February 17, 1997.

On February 17, 1997, B.C. Hydro filed a new WTS Application with the Commission which contained B.C. Hydro's response to the Commission's directions. Included in this filing was a proposal for a single wholesale transmission tariff, based on capacity reservations. The proposed tariff consisted of a two-part rate: one part reflecting locational long-run incremental costs ("LRIC") and the second part (access fee) collecting the balance of the revenue requirement. As part of the February filing, B.C. Hydro requested interim approval of the proposed rates effective April 1, 1997. This was granted by way of Commission Order No. G-31-97. No process was established for the disposition of this Application at that time due to the scheduled Retail Access and Unbundled Tariff Hearing. After cancellation of that hearing, Commission Order No. G-53-97, dated May 15, 1997, established that B.C. Hydro's

February 17, 1997 WTS Application would be disposed of through negotiated settlement to commence September 22, 1997, or by public hearing if a settlement were not achieved.

However, on June 20, 1997, B.C. Hydro made a substantial revision to the February 17, 1997 filing and requested that the revised WTS Application ("the Application") be given interim approval. In essence, these revisions brought B.C. Hydro's proposed tariff into conformity with the Federal Energy Regulatory Commission's ("FERC") Order No. 888-A pro forma tariffs and resulted in the abandonment of the two-part capacity reservation tariff. Commission Order No. G-77-97 granted interim approval of the revised Application effective August 1, 1997. In the covering letter, the Commission stated that the issues related to electricity trade and the impact that the revenues from these trades have on maintaining low rates for B.C. Hydro's customers required that interim approval be given. However, the Commission stated that it was concerned that the amended Application constituted a significant departure from the February 17, 1997 filing, and in particular, from certain specific directions made by the Commission in its June 25, 1996 Decision. As a result, the Commission made plain that the interim approval was given on a without-prejudice basis to the Commission's final determinations and that the Commission no longer viewed a negotiated settlement as the proper method for disposition of this Application.

Commission Order No. G-83-97 established that a public hearing into the revised Application would begin on November 17, 1997. However, in October, the Commission received a request from the Council of Forest Industries, the Mining Association of British Columbia and certain Electro-Chemical Producers ("the Industrial Customers") for a postponement of the hearing. After canvassing the Utility and the Registered Intervenors, Commission Order No. G-105-97 was issued which rescheduled the hearing to commence on January 19, 1998.

There were nine hearing days during which the Commission heard evidence from four B.C. Hydro witness panels on policy matters, transmission revenue requirement, rate design and terms and conditions. In addition, the Commission heard evidence from WKP, a group of Large Industrial Customers, and the Bonneville Power Administration ("BPA"). Further, the Commission accepted submissions from the Association for the Advancement of Sustainable Energy Policy ("AASEP") and from the Grid Company of Alberta ("Gridco"). The evidentiary portion of the hearing ended on January 29, 1998 with final argument received thereafter.

1.2 Description of Current Application

As indicated above, the February 17, 1997 filing was an attempt by B.C. Hydro to provide WTS tariffs which were consistent with the directions contained in the Commission's June 24, 1996 Decision, both with respect to the transmission revenue requirement and rate design. The revisions contained in the

June 20, 1997 filing brought the Application into conformity with FERC Order No. 888-A. As a result, the Application no longer reflected all of the directions contained in the original Decision, particularly as these directions applied to rate design.

With respect to rate design, the main revisions to the February 17, 1997 filing were as follows:

1. *Inclusion of a separate Network Integration Transmission Service along the lines approved in the 1996 Commission Decision and contained in FERC Order 888-A.*. The February 17, 1997 filing had removed the distinction between Network and Point-to-Point Service and instead offered a single tariff, based on capacity reservations, for all Wholesale Transmission customers and B.C. Hydro on a comparable basis. The June 20, 1997 filing brought back both forms of service.

2. *Elimination of the deviations in the February 1997 Tariff to cover Network customers under the single capacity reservation tariff.* The Terms and Conditions approved by the 1996 Commission Decision were based on separate Network and Point-to-Point Services. Since the February 17, 1997 filing did not contain a specific provision for network service, it was necessary to alter the original Terms and Conditions to reflect the conditions for service of customers with multiple points of receipt and delivery. In the June 20, 1997 filing, these deviations were eliminated.

3. *Use of a single part rate form, consisting of a reservation charge, for Long-Term Point-to-Point service.* The February 1997 Tariff provided for a two-part rate form, consisting of a reservation charge with a path specific LRIC component, together with an access charge set to collect the Transmission Revenue Requirement.

4. *Adoption of the industry standard Loss Compensation charge based on system average losses instead of incremental losses.* The February 17, 1997 filing had proposed a loss compensation service which included a credit for transactions resulting in reduction of system losses. It had also removed the asymmetric treatment of losses that had been contained in the 1996 filing.

5. *Modifications to the Energy Imbalance schedule to bring it into line with the industry standard.*

6. *Further unbundling of Ancillary Services resulting in additional schedules.* Under both the February 17, 1997 filing and the June 20, 1997 filing, Ancillary Services are cost-based.

In addition, the June 20, 1997 filing retained certain rate design changes that had been proposed in the February 17, 1997 filing. These included:

1. *An auction mechanism for allocation of capacity at the B.C. - Alberta intertie.*

2. *A change to the way in which Short-Term Firm Service was charged.* Under the tariffs approved by the 1996 Decision, Short-Term Firm Service was charged a seasonally differentiated fixed price. Under the new Application, B.C. Hydro proposed to charge for Short-Term Firm Service based on the charge for Short-Term Non-Firm Service plus a flexible premium of no less than one mill. The rate for Short-Term Firm Service is capped at the Long-Term Firm Service Rate, adjusted for the time period.

3. *The development of price indices for loss compensation service.*

As indicated above, the June 25, 1996 Decision directed B.C. Hydro to develop a Transmission Revenue Requirement that reflected the relative benefits which generation-related transmission assets provide to the generation and transmission functions, the extent to which 138 and 69 kV lines provide transmission benefits and the role of DSM with respect to transmission. The Transmission Revenue Requirement contained in the February 17, 1997 filing reflected B.C. Hydro's view that 5/7th of the generation related transmission assets, 100 percent of the 138 and 69 kV lines and none of the demand-side management ("DSM") costs should be functionalized to transmission. The June 20, 1997 filing did not significantly alter the February 17, 1997 filing with respect to this issue.

2.0 TRANSMISSION REVENUE REQUIREMENT

During the course of the 1996 WTS hearing, the Commission heard substantial debate concerning:

- the relative benefits which generation-related transmission assets provide to the generation and transmission function;
- the extent to which 138 kV and 69 kV lines provide transmission benefits; and
- the role of DSM with respect to transmission.

Based on evidence at that hearing, the Commission concluded that further study was needed to more precisely identify the benefits provided to transmission by these assets. Accordingly, the June 25, 1996 Decision directed B.C. Hydro to undertake a set of studies that would more precisely identify the benefits under discussion. Further, the decision directed B.C. Hydro to file new rates reflecting the results of these studies.

2.1 Generation Related Transmission Assets

In its June 25, 1996 Decision, the Commission judged that B.C. Hydro had not justified the functionalization of generation related transmission assets ("GRTAs") to transmission. The Commission agreed with B.C. Hydro that remote generation sources may provide benefits to the transmission network in the event of an emergency and may be called upon to provide ancillary services. However, the Commission determined that the Utility had not demonstrated the magnitude of the benefit provided by these assets.

Accordingly, the Commission did not accept that the evidence provided justified functionalizing 100 percent of the cost of GRTAs to transmission. The Commission directed B.C. Hydro to develop a new transmission revenue requirement that reflected the relative benefits provided by the GRTAs to both the generation and transmission functions.

2.1.1 B.C. Hydro Proposal

In its June 20, 1997 Application, B.C. Hydro filed rates based on a transmission revenue requirement ("TRR") that reflected an allocation of the GRTAs between generation and transmission based on the Utility's assessment of the relative benefits that these assets provide to the two functions.

B.C. Hydro took the position at the outset of this hearing that the assets which comprise the GRTAs had been explicitly defined by the Commission in its June 25, 1996 Decision as those facilities linking the remote generation to the first inter-connection point (T: 446). Further, B.C. Hydro asserted that its interpretation of the Commission's definition of the GRTAs was well established and tested by the actions of the Utility leading up to this hearing (T: 668).

The assets in question have an associated revenue requirement of $77 million. According to B.C. Hydro, there is no industry precedent for splitting the functionalization of these assets based on their relative benefits to generation and transmission. B.C. Hydro, therefore, developed a methodology based on a hypothetical construction of thermal generators located at the load-side termini of the assets that B.C. Hydro interpreted to be in dispute (Exhibit 5, Tab Mansour, Attachment 1). In place of the remote hydro facilities in the Peace and Columbia regions, thermal generating facilities were nationally constructed at Williston and Nicola.

This methodology was developed in a study titled A Comparison of the Benefits Provided by Generation-Related Transmission Assets to the Generation and Transmission Functions in B.C. Hydro's System ("the Comparison Report").

B.C. Hydro's position is that the nature and flexibility of the existing remote hydro facilities allows the system to be operated in a more cost efficient manner than would be possible with a thermal equivalent system located closer to the load. This flexibility is offered in the form of generation shedding, series compensation, high-speed re-closing, and electric braking. B.C. Hydro maintains that the hydro-based system offers value in these areas which exceeds the costs of the disputed facilities.

The Comparison Report concluded that in place of seven 500 kV lines connecting Mica, Revelstoke, and the Peace River plants to the integrated grid, five equivalent length and cost 500 kV lines would be required to connect thermal facilities at Williston and Nicola. These were added as follows:

- two from Williston to Kelly Lake;
- one from Kelly Lake to the Lower Mainland; and
- two from Nicola to the Lower Mainland.

B.C. Hydro argued that such a substitution would preserve the same performance levels as the existing system, recognizing the hydro system's operating flexibility.

From the Comparison Report (and related studies), B.C. Hydro developed four possible alternatives for analyzing the outcomes in a manner consistent with the Commission's determination. These are labeled as Alternatives A through D.

Alternative A was derived from B.C. Hydro's analysis that roughly $55 million of the $77 million total GRTA revenue requirement provides benefits to transmission. Therefore, this amount (i.e., 5/7th of the total) should be added to the TRR for the non-generation-related transmission assets.

Alternative B compared the annualized costs of the hypothetical thermal system to the annualized costs of the hydro system, and concluded that the difference ($89 million) is the benefit to the hydro system of the $22 million of GRTAs functionalized to generation. This alternative was offered as justification for the 5/7th figure calculated in Alternative A.

Alternative C calculated a benefit to generation of $110 million from the GRTAs. Along with the benefit-to-transmission figure of $55 million (from Alternative A), this suggests a 2:1 relative benefits ratio, or a functionalization of 1/3rd of the GRTAs to transmission and 2/3rds to generation.

Alternative D suggested a 100 percent allocation of the GRTAs to transmission, based on B.C. Hydro's interpretation of the methodology used in Alberta.

From these four alternatives, B.C. Hydro concluded that allocating 5/7th of the GRTAs to transmission and 2/7th to generation is reasonable and supported by the analysis. This 5/7th ratio was, therefore, taken as the relative benefit of the GRTAs to transmission, and was applied to all of the disputed assets, including substation facilities (i.e., the entire $77 million of the GRTAs).

With B.C. Hydro's filing of its direct evidence, an alternative proposition emerged from the Utility. While the definition of the GRTAs remained fixed, the Utility's proposal for their treatment changed.

B.C. Hydro expressed this new approach when it stated that if it looks, walks and talks like a transmission asset then that is what it is and that is how it should be treated (Exhibit 5, Barnett, p. 12).

B.C. Hydro viewed this approach – which, in its Final and Reply Arguments it referred to as "If It Looks, Acts, Talks and Walks Like Transmission, Then It Probably Is" – as an effort "to characterize facilities based on what they are (T: 1449).

If adopted, this approach would include all of the $77 million of revenue requirement associated with the GRTAs in the TRR, based on B.C. Hydro's proposed definition of 'cut-offs' at either end of the transmission system. At the generation-end, B.C. Hydro proposed that the cut-off needs to occur as the power leaves the generator. For the other (distribution) terminus, B.C. Hydro proposed the high-end of the step-down transformer.

B.C. Hydro noted evidence to suggest that its generation-side approach is consistent with most FERC jurisdictions, while its distribution-side approach is conservative; a number of other jurisdictions draw the cut-off at the low-end of the step-down transformer (T: 1449-1450).

Also in its Final Argument, B.C. Hydro identified a second variant of the "If It Looks, Acts, Talks and Walks Like Transmission, Then It Probably Is" approach. This variant, according to B.C. Hydro, is used by Bonneville Power Administration, and differs only in detail from the methodology proposed by B.C. Hydro. Specifically, this alternative would define transmission as beginning at the first node on the system (moving away from the generator, this would be the first substation encountered by energy moving toward load, and would generally be located very near to the generating facility). At the other end, BPA's practice differs more sharply from B.C. Hydro's proposal, as the American utility allocates to transmission all expenses down to the low-side of the step-down transformer.

As to its preferred approach for the GRTAs, B.C. Hydro endorsed either of these variants on the grounds that they are simple and capable of fair and consistent application (T: 1453). As well, B.C. Hydro argued that any concerns about the burden that these approaches might impose on particular classes of customer – or any limiting effect they might have on competition – are best addressed through rate design, not through artificially structuring the revenue requirement (T: 1787).

In contrast, B.C. Hydro described the relative benefits approach as complex, uncertain in result, fraught with the potential for future controversy, and inconsistent with past and evolving practice. As such, B.C. Hydro took the position that the Commission should abandon this approach (T: 1439).

This treatment of generation integration leads makes linking IPPs to the integrated grid an important issue concerning the allocation of the GRTAs[1]. In an information request, BPA sought to explore the comparability between B.C. Hydro's treatment of the GRTAs, and its proposed treatment of radial lines linking generation owned by others (Exhibit 2, p. II-BPA IR 1, Question 23-1). In response to a follow-up question, B.C. Hydro stated that it would consider building generation leads for generating units owned by others and including those costs in the TRR if those facilities provided benefits to the system of a kind comparable to the benefits that B.C. Hydro asserted were provided by its own generation leads

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[1] Generation integration leads are normally defined as the section of line from the generation switchyard to the first node on the integrated grid. This definition works well on simple systems, but can become troublesome when applied to more complicated networks. This definitional problem was highlighted in the hearing, at which considerable debate surrounded both the definition of the GRTAs and the functionalization approach used by the Bonneville Power Administration.

(Exhibit 3, p. III-BCUC IR 2, Question 23-1). The question of whether this would hold true regardless of the nature of the generating facilities – i.e., hydro or thermal – was not addressed.

2.1.2 Criticisms of the B.C. Hydro Proposals

Criticisms were made of B.C. Hydro's proposed GRTA approach in several areas. In particular, it was asserted that B.C. Hydro:

- is incorrect in its definition of the GRTAs;
- has chosen an inappropriate size and location for the hypothetical thermal generators used in its relative benefits model;
- has disregarded historical evidence about why the transmission system developed as it did;
- has mis-defined and mis-interpreted the results of its relative benefits study;
- did not consider in its Comparison Report that the stability benefits of hydro are needed only because of the remoteness of those very facilities; and
- is inconsistent in its treatment of the GRTAs compared to IPP generation leads.

In addition, the Commission notes that Alternatives B and C in the Comparison Report relied on comparisons of the economic benefits of the existing hydro system relative to the notional thermal one. The Commission has two concerns in this regard. First, the annualized cost of new generation is treated as commensurate with that of a partially depreciated existing transmission system. Second, no account is taken of the likelihood that the notional thermal system could be built in stages. Although these concerns cast doubt on the magnitude of the net benefit that could be attributed to the hydro system, the Commission did take into account the logic of the arguments.

Definition of the GRTAs

Questions were raised at various points of this proceeding with respect to B.C. Hydro's definition of the GRTAs. As indicated earlier, B.C. Hydro's definition of the GRTAs is driven by decisions made in the 1993/94 FACOS study which was filed in the previous WTS hearing. As such, the GRTAs include the 500 kV transmission system north of Williston and east of Nicola and Ashton Creek.

The evidence of Mr. Nieboer, a witness for WKP and the Industrial Customers, sought to expand the Commission's relative benefits direction to all B.C. Hydro transmission assets.

Although B.C. Hydro was unequivocal that, apart from the GRTAs as the Utility has defined them, there could be no doubt about the appropriate allocation of other transmission assets (T: 495), the Industrial Customers disagreed with B.C. Hydro's definition, seeing it as too selective (T: 1472).

Size and Location of the Hypothetical Thermal System

The location of the generators used in B.C. Hydro's hypothetical thermal system to determine the relative benefits of the GRTAs raised concern with several intervenors. B.C. Hydro acknowledged that the outcome of its approach is sensitive to the location of the hypothetical thermal alternatives, and that there can be no clear way of demonstrating the appropriateness of any particular location (Exhibit 2, p. II, BCUC IR 1, Question 62-1).

According to the Industrial Customers, by locating the hypothetical thermal plants at the load-side termini of what B.C. Hydro defined as the GRTAs, the Utility overstated the costs and understated the benefits of a thermal equivalent and, therefore, overstated the benefits accruing from remote hydro. The Industrial Customers argued that a meaningful thermal alternative must locate the thermal plants taking into account the location of the energy source and the location of the loads.

With respect to the size of the facilities "constructed" in the hypothetical thermal alternative, Mr. Nieboer stated that even if the hypothetical thermal system were a relevant model, at these remote locations the notional thermal generators described by B.C. Hydro are too large (Exhibit 41, p. 12). By Mr. Nieboer's calculations, the hypothetical thermal equivalent suggested by B.C. Hydro is capable of producing at least 60 percent more energy than the hydro plants it replaced.

The Historic Development of B.C. Hydro's System

Several intervenors expressed concern that by choosing a hypothetical thermal model to address the question of relative benefits, B.C. Hydro ignored historical evidence about how the electrical grid evolved, and why certain assets were acquired in the first place. These intervenors dismissed suggestions that the system's development was driven primarily by political decisions, saying, instead, that B.C. Hydro's contemporary internal documents show a system built on economic grounds where competing projects were tested on the basis of the total cost of generation and transmission.

Moreover, many intervenors noted that B.C. Hydro's own consultant, R.J. Rudden and Associates, had adopted a similar view in a report attached to B.C. Hydro's 1993/94 FACOS study. That report stated that remote generation provides for cheaper generation but carries with it an additional transmission cost. Accordingly, the report viewed the cost of that remote generation as part of the cost to generation that should not be functionalized to transmission (Exhibit 16, R.J. Rudden and Associates, p. 8).

Interpretation of the Relative Benefits Study

As indicated earlier, B.C. Hydro considered four alternative interpretations of the results of its Comparison Report under the heading "Comparison of the Benefits Provided to Generation and Transmission."

Several intervenors expressed dissatisfaction with B.C. Hydro's interpretation of its own results. For example, the Alberta Department of Energy ("ADOE") submitted Final Argument that contained criticisms of Alternatives A, B, and D, as they are described in B.C. Hydro's Comparison Report.

With respect to Alternative A, ADOE stated that B.C. Hydro had determined the relative benefits of transmission assets to transmission and generation, and then switched to absolute terms in assigning the $55 million in benefits to transmission. ADOE stated that it would appear equally justifiable for the shift to absolute terms to be done in favour of assigning the absolute benefit of $110 million to generation. ADOE stated that Alternative B, which B.C. Hydro characterized as support for Alternative A, contained a fallacious argument. ADOE agrees with B.C. Hydro that the $89 million in savings to the system provided by the "extra" $22 million in GRTAs offers justification for B.C. Hydro's remote generation facilities. However, ADOE disagrees that this provides justification for allocating 5/7th of the GRTA costs to transmission (T: 1721).

ADOE was also critical of Alternative D, stating that B.C. Hydro had mischaracterized this approach when it described it as being analogous to the approach taken in Alberta. ADOE stated that B.C. Hydro's characterization of the Alberta legislation was incorrect.

The Industrial Customers also criticized Alternative D, calling it superficial. As well, they disputed Alternatives A, B, and C, on the grounds that these alternatives have their roots in the hypothetical thermal system, which the Industrial Customers argued "… offends common sense to such a degree that is has no value and should be dismissed summarily." (T: 1473).

Enron Capital and Trade Resources Canada Corporation ("ECT Canada") also raised a number of concerns about B.C. Hydro's Comparison Report, including the Utility's definition of viable alternatives. ECT Canada was critical of B.C. Hydro's decision to ignore an alternative which assigns 100 percent of the GRTAs to generation, as in the 1993/94 FACOS study. ECT Canada indicated that this approach is valid because it is reflective of the way in which the system is planned and operated (T: 1559).

ECT Canada also leveled criticism at all four of B.C. Hydro's listed alternatives. ECT Canada stated that Alternative D is not responsive to the Commission's direction to assess relative benefits and while

Alternative A does speak to the relative benefits to transmission, it is silent on the relative benefits to generation. With respect to Alternatives B and C, ECT Canada asserted that these alternatives indicate only that the generation savings of $110 million are more than sufficient to offset 100 percent of the revenue requirement associated with the GRTAs (T: 1560).

Stability Requirements and Benefits of Remote Hydro

As indicated earlier, B.C. Hydro justified its hypothetical thermal alternative by noting that hydro generating facilities are capable of supporting system stability to a far greater extent than are thermal generating facilities. B.C. Hydro developed its hypothetical thermal system in consideration of the need to replicate this stabilizing capability.

Intervenors pointed out what might be considered a circularity in the B.C. Hydro argument. The Industrial Customers stated that while hydro generation does bring benefits to a system, some of the problems in B.C. Hydro's system are caused by the remoteness of that generation (T: 1475).

Treatment of GRTAs compared to IPP Generation Leads

The appropriateness of B.C. Hydro's proposed policy of charging for new facilities was criticized in the pre-filed evidence of Drazen Consulting Group (Exhibit 37). Mr. Drazen and Ms. Pearson, testifying on behalf of the Industrial Customers, questioned whether protections exist in the proposed Tariff to ensure that the cost of independent suppliers' generation facilities will be treated in the same manner as new capacity from B.C. Hydro Power Supply. Mr. Drazen and Ms. Pearson asserted that B.C. Hydro has changed its position in this regard since the 1996 WTS hearing, and that the new approach offers insufficient assurance that IPP generation leads will receive the same treatment as lines connecting new B.C. Hydro generation to the grid (Exhibit 37, p. 13).

They noted that in response to information requests, B.C. Hydro indicated that treatment akin to the GRTAs would apply to IPPs that could demonstrate a comparable system benefit (Exhibit 3, p. III-BCUC IR 2, Question 23). Still, Mr. Drazen and Ms. Pearson argued that "since the determination of whether and how much certain facilities provide a benefit to generation and transmission is open to question, all stakeholders will not receive equal treatment unless the entity making the determination is independent from generation" (Exhibit 37, pp. 13-14).

2.1.3 Alternative Proposals

Alternative proposals for the definition and treatment of the GRTAs were explored in this proceeding under two broad themes. First, with respect to the Commission's relative benefits direction, Mr. Nieboer presented a methodology which he termed segmentation. This approach is fundamentally different from the Comparison Report methodology advocated by B.C. Hydro. Second, with respect to the "If It Looks, Acts, Talks and Walks Like Transmission, Then It Probably Is" approach, intervenors differed with B.C. Hydro on the functionalization methodology employed by BPA.

<u>The Relative Benefits Approaches</u>

In his direct evidence, Mr. Nieboer provided a segmentation study that he stated reflected the relative benefits which a broad spectrum of assets provides to the generation and transmission functions (T: 1324). Using load flow analysis, he attempted to demonstrate that roughly 70 percent of B.C. Hydro's 500 kV transmission assets should be viewed as connecting remote hydro generation to the major load centers in the Lower Mainland and on Vancouver Island. Specifically, he asserted that of more than 7000 MW sent into the generation-end of the transmission lines, more than 5000 MW are delivered to the load centers of Vancouver Island and the Lower Mainland. Accordingly, he asserted that this should be taken into account in distinguishing the generation and transmission benefits of 500 kV lines and, hence, their functionalization.

By extension, Mr. Nieboer asserted that "broad brush" cost analysis shows that between $1.59 and $1.92 billion of transmission assets (on a depreciated basis) needs to be "carefully examined as to where these costs should be properly allocated" (Exhibit 41, Appendix 1, p. 2).

Mr. Nieboer also stated that the broad system benefits attributed by B.C. Hydro to its remote hydro facilities are provided for in the pricing of ancillary services. Therefore, Mr. Nieboer expressed concern that B.C. Hydro not be credited for contributions to the system for which it will already receive compensation through the ancillary service schedules.

Several intervenors supported the approach suggested by Mr. Nieboer, although some took the view that more work is required to translate his ideas into a practicable solution. For example, the Industrial Customers argued that if the Commission feels that Mr. Nieboer's evidence lacks sufficient detail on which to base a final decision, the Commission could direct B.C. Hydro to enter into consultations with the stakeholders in this proceeding to seek agreement on asset allocations based on Mr. Nieboer's approach. If that did not work, the same group could draft terms of reference and choose a consultant to carry out a detailed study.

Fording Coal took a similar view, but argued that any study should be driven by the Commission; meanwhile, Mr. Nieboer's allocation approach should be adopted on an interim basis.

CBT Power Corp. supported the approach of Mr. Nieboer, adding suggestions for allocating specific groups of assets. In its Final Argument, WKP also provided detailed suggestions for allocating assets between generation and transmission.

ZE Power Group Inc. took what might be seen as a hybrid position on the GRTAs. It recommended that all of the GRTAs as B.C. Hydro defined them should be functionalized to generation but, in addition, B.C. Hydro should provide written argument to the Commission with respect to the individual functionalization of all additional lines identified for exclusion from the TRR by Mr. Nieboer.

Characterization of BPA's Approach to Functionalization

Like B.C. Hydro, some intervenors examined BPA as a model for the treatment of the GRTAs. However, the characterization of the BPA approach to functionalization differed sharply in the evidence of the Utility compared with the evidence of the intervenors.

Mr. Saleba, a witness for WKP, observed that BPA does not include generation leads in its transmission rates. He stated that BPA considers all facilities that interconnect the generating plants with the load centers, including the transmission lines and equipment from the generating plant step-up transformer to the first transmission system substation encountered by the generated power, as related to generation and functionalized to its generation function (Exhibit 27, p. 13). However, under cross-examination, Mr. Saleba stated that his expertise with respect to BPA concerned rate setting (T: 941).

In addition, BPA stated that for the period October 1996 through September 2001, it functionalized step-up transformers at Federal generators to the generation function. As well, BPA stated that it "defined a Generation-Integration segment (the transmission line and equipment between the generating plant step-up transformer and the first sub-station on the integrated BPA network encountered by the generated power) whose costs were functionalized to the transmission function, but the costs were assigned to Federal power" (Exhibit 35B, p. 2).

Without specifically commenting on the BPA approach, WKP took the position that step-up transformers "should be charged to generation because they "condition" generation output for transmission, that is, it raises generation voltage to transmission voltage" (T: 1512).

B.C. Hydro stated that BPA's description of its functionalization process is ambiguous. In an attempt to clarify the evidence, B.C. Hydro stated that "the first node on the system is the one located right near a generator, with no qualification as to the proximity of that generator to load" (T: 1451).

2.1.4 Criticism of the Alternate Proposals

The Relative Benefits Approaches

Inherent in many intervenors' support for Mr. Nieboer's segmentation analysis is the notion that B.C. Hydro's hypothetical thermal model is fundamentally flawed. These flaws center on the size and location of the notional facilities.

B.C. Hydro did not concede these short-comings. With respect to the location of the hypothetical thermal generators, B.C. Hydro argued that its model is not intended to replicate what might have happened over the past 30 years – something it describes as "unknowable". Instead, B.C. Hydro stated that the model places notional generators at Nicola and Williston because these are the load-side termini of the GRTAs being analyzed.

With respect to the capacity of the notional generators, B.C. Hydro and Mr. Nieboer agreed that electrical systems are sized considering demand, not energy. In addition, B.C. Hydro stated that its system is in "virtual capacity-demand balance. Therefore, the assumption that the capacity of the notional thermal alternative being equal to the capacity of the existing hydro facilities is not only reasonable but vital to meet demand" (T: 1774).

B.C. Hydro attempted to illustrate that Mr. Nieboer's study shows only what B.C. Hydro has characterized as the unsurprising result that since some 70 percent of B.C.'s population is concentrated in the southwest of the province, that is where roughly the same proportion of power is consumed (T: 1319-1320).

Further, B.C. Hydro sought to show that Mr. Nieboer's study falls short of the Commission's direction to undertake a relative benefits analysis. Specifically, B.C. Hydro asserted that Mr. Nieboer's study takes no account of the benefits that the GRTAs bring to the system as a whole (despite this short-coming, Mr. Nieboer's approach is referred to by B.C. Hydro as "The Unrestricted Relative Benefits Approach").

B.C. Hydro argued that every generation and transmission asset is part of an integrated system. Therefore, any attempt to assign the value of assets between functions is artificial, subjective, and imprecise. Moreover, the functionalization determined for any given asset would have only transient value, and would have to be adjusted constantly to reflect changes in the use of other assets on the system. Worse, the exercise would have to be applied to all assets, both generation and transmission (T: 1433-1434).

B.C. Hydro and the Consumers' Association of Canada (B.C. Branch) et al. ["CAC (B.C.) et al."] also disagreed with the notion that the Unrestricted Relative Benefits Approach is a good starting point for more consultation and study. B.C. Hydro argued that both the Unrestricted Relative Benefits Approach – and, for that matter, the Hypothetical Thermal Approach – have inherent problems that render them as unsuitable foundations for the Commission's decision, no matter how much more study is tried. The CAC (B.C.) et al. argued that there is no "right" answer to the question of how to functionalize these assets, a proposition conceded by Mr. Nieboer (T: 1293). Given this, the CAC (B.C.) et al. asserted that the Commission's decision becomes a subjective policy question about the division of rents and costs between customer groups (T: 1643).

With respect to the argument that the stability benefits described by B.C. Hydro should correctly be captured in the pricing of ancillary services, B.C. Hydro drew a distinction between optional services and those that are necessary. B.C. Hydro indicated that the benefits provided through the transmission system are not optional, but instead benefit all users of the transmission system by providing basic stability.

With respect to the argument that the GRTAs simply offset stability problems that the GRTAs themselves have caused, B.C. Hydro stated that no substantive evidence was offered in this regard. B.C. Hydro acknowledged that instability is a characteristic of electrical systems but stated that its notional thermal system study shows that the long lines correct instability and support a transmission system even where generation is located closer to load. (T: 1772-1773)

2.1.5 Commission Determination

Based on the evidence and argument presented with respect to this application, the Commission is satisfied that the GRTAs at issue in this proceeding are those assets defined by B.C. Hydro (Exhibit 5, Tab Mansour, Attachment 1).

With respect to these assets, the Commission appreciates B.C. Hydro's efforts to respond to its directive as contained in the June, 1996 Decision; a difficult task to be sure, and one seemingly without methodological precedent.

The evidence in this proceeding clearly illustrates that where a physical asset, remote generation, produces two outputs as a joint product – in this case, electricity and stability for the transmission system – there has been no accepted procedure for assigning costs to the respective outputs. Here, where the asset has two identifiable components, generation and transmission, a further step is required: apportionment of the cost assigned to each of electricity and stability between the asset components. This entire procedure would be highly subjective (Exhibit 2, BCUC IR 1, Question 64). Despite the efforts of B.C. Hydro, the Commission is not convinced that the hypothetical thermal approach developed by the Utility is a viable methodology for splitting the GRTAs between functions based on their relative benefits.

Further, the Commission recognizes, but is not persuaded by, the simplicity argument set out in B.C. Hydro's favoured "If it Looks, Acts, Talks, and Walks Like Transmission, Then it Probably Is" approach. The Commission is not convinced that B.C. Hydro has pursued this approach with enough rigour to demonstrate that it is fair to all ratepayers and that it will lead to the kind of efficient pricing sought by the Commission.

From a broader perspective, the Commission believes that B.C. Hydro has failed to demonstrate that it incurred any costs in order to enjoy the system stabilization benefits provided by its remote hydro facilities. The available evidence suggests that the remote hydro facilities were built on reasonable economic grounds – that is, stability benefits aside, the delivered cost of power from these hydro generators and their related long transmission lines was less than whatever thermal alternatives decision-makers at the time may have had available to them. This means that the stability benefits, while certainly valuable, were won at no explicit cost to the Utility.

The issue then becomes: will transmission users receive enough benefits from the GRTAs to warrant having some of these costs allocated to them? On this question, the Commission notes that it is not the GRTAs which provide the stability benefits, but rather the hydro generators that the GRTAs attach to the grid. The Commission, therefore, is not satisfied that it is logical to charge transmission for stability benefits on one relatively narrow aspect of a broad integrated system, while not charging on a similar basis for the hydro generation assets that actually provide the stabilizing effects.

If this leads to the implication that B.C. Hydro Power Supply may wish to charge for the stabilization benefits as an ancillary service, the Commission notes that such services are generally priced through a cost-based approach and, for the reasons explained above, the Commission is not satisfied that B.C. Hydro incurred any cost to create the stabilizing effects of a hydro system.

On the issue of BPA's approach to segmentation between generation and transmission, the Commission accepts B.C. Hydro's position that, on the evidence presented, the BPA approach appears generally analogous to the approach advocated by B.C. Hydro in its Final Argument. However, the Commission notes the many differences between the B.C. Hydro and BPA service areas, and is not persuaded that the two systems must necessarily be bound by similar functionalization methodologies.

Therefore, the Commission directs B.C. Hydro to file an adjusted transmission revenue requirement and associated tariffs that reflect functionalizing 100 percent of the GRTAs to

generation. This Decision, therefore, directs a treatment of the GRTAs similar to that found in the 1993/94 FACOS study.

2.2 69 kV and 138 kV Lines

In its June 25, 1996 Decision, the Commission accepted that certain parts of the 69 kV and 138 kV system provide transmission benefits, and determined that all of B.C. Hydro's 69 kV and 138 kV facilities should be functionalized to transmission. At the same time, however, the Commission ordered that B.C. Hydro file a study demonstrating the extent to which 69 kV and 138 kV lines provide transmission benefits. That report (“the 69/138 kV Report”) forms part of the present Application.

2.2.1 B.C. Hydro Proposal

B.C. Hydro's study concluded that the major benefits of the 69 kV and 138 kV lines relate to transmission and, therefore, that all these assets should be functionalized to transmission.

B.C. Hydro's position in the 69/138 kV Report is that the 69 kV and 138 kV lines provide a major benefit to transmission by off-loading the higher voltage (i.e., 500 kV) circuits, thereby strengthening the overall transmission system. This increases the transmission capacity available for wholesale purposes while providing a more reliable system. For the majority of lines, this benefit is achieved because the lower voltage lines parallel higher voltage ones. In some cases, the lower voltage lines integrate local or regional generation and, to the extent that this reduces the need for additional transmission facilities, these assets are correctly categorized to transmission.

B.C. Hydro reviewed its integrated transmission system against a three-factor test which it stated is consistent in outcome with the FERC seven-factor test to determine whether facilities are transmission or high-voltage distribution (T: 825). From this study, B.C. Hydro determined that a significant majority – roughly 70 percent by distance – of 69 kV and 138 kV assets provide benefits to the transmission system, either by integrating local generation or by paralleling the higher voltage system.

In the 69/138 kV Report, future system development is given as the primary justification for jumping from the share-providing-benefits figure of 70 percent to the 100 percent-inclusion figure sought by the Utility. Notably, B.C. Hydro cited the possible expansion of IPP generation in the service of regional load growth, and expected regulatory developments regarding both bulk customer wheeling and municipal electric utilities (Exhibit 1, p. I-CR-1-4).

However, the explanation for functionalizing 100 percent of these lines to transmission was expanded at the hearing. In its testimony, B.C. Hydro took the position that these assets cannot readily or sensibly be divided between functions. B.C. Hydro also asserted that 138 kV assets cannot properly be described as distribution lines (T: 768-769). Moreover, the Utility argued that since a number of the lines included in the 30 percent figure are likely used to serve customers that take power at transmission voltage, it does not make sense to include them in the distribution revenue requirement (T: 832).

Under questioning, B.C. Hydro witnesses explained that attempting to allocate the 69 kV and 138 kV systems between functions would require specific cost studies for each of the lines in question, a process that would likely take "a couple of months" (T: 833).

Further, should the Commission rule that only 70 percent of these assets could be included in the TRR, B.C. Hydro indicated an immediate problem of determining what the TRR should be. B.C. Hydro witnesses explained that the result of such an approach might be seen as point-specific rates within network service. The outcome could be a significant rate hike for customers who located on the system decades ago. This would be due simply to the introduction of wholesale wheeling, a development which might have nothing to do with these customers.

The B.C. Hydro witnesses emphasized that despite these problems, splitting the 69 kV and 138 kV assets between functions is possible. They noted, however, that doing so would be relatively expensive and unlikely to generate any meaningful efficiency gains.

In addition, B.C. Hydro raised concerns about how it would allocate the 30 percent of assets that do not meet B.C. Hydro's criteria for providing a transmission benefit. The Utility noted that since a number of these lines are used in the service of customers that take service at transmission voltage, the assets cannot simply be functionalized to distribution; an approach favoured by some intervenors (T: 832-833 and T: 1481).

2.2.2 Criticism of the B.C. Hydro Proposal

Criticism of B.C. Hydro's proposed treatment of the 69 kV and 138 kV assets raised three major areas of dispute, which mirror roughly B.C. Hydro's categories of potential benefits from 69 kV and 138 kV assets: (1) generation integration; (2) load sharing and back-up to higher voltage systems; and (3) access for wholesale customers.

Broadly speaking, several intervenors questioned the fairness to third-party wholesale users of the transmission system if all costs associated with the 69 kV and 138 kV system are included in the TRR. For example, WKP noted that while it is appropriate for wholesale transmission customers to pay all costs associated with moving power from one node to another within a "meshed/parallel operated" transmission system, it is not appropriate for them to pay the cost of radially configured and operated lines, which do not serve a general network function (T: 1513).

WKP also observed that B.C. Hydro's figures for 69 kV and 138 kV radial and generation integration lines changed significantly during the course of this proceeding, and that this suggests the need for a significant re-valuation of the issue.

Mr. Drazen and Ms. Pearson argued that assets identified by B.C. Hydro as serving the generation-integration function should be excluded from the TRR for the same reason that they believed the GRTAs should be excluded (Exhibit 37, p. 11). They argued that while it might be difficult to determine from a strictly technical standpoint which facilities should be considered system-related and which local, the issue must be considered in light of the principles involved and the potential impact. They stated that including lower voltage facilities in the TRR provides an opportunity for costs that should be the responsibility of B.C. Hydro Distribution to be included, instead, in the rates of B.C. Hydro Transmission. They asserted that the effect is to require others to subsidize B.C. Hydro Distribution (Exhibit 37, p. 12).

Mr. Drazen and Ms. Pearson also commented on the second major area of concern regarding the B.C. Hydro proposal. They noted that B.C. Hydro proposes to include all of the cost of 69 kV and 138 kV assets in the TRR because the majority of these assets meet the criteria of the B.C. Hydro study. They argued that this was an insufficient reason for their inclusion.

In his evidence, Mr. Saleba made similar observations, noting that cost causation principles would allocate to wholesale transmission customers only those costs that the wholesale transmission customers caused to be incurred (Exhibit 27, p. 15).

Mr. Saleba also noted that FERC has a seven-factor test to determine whether assets are transmission or high-voltage distribution. He suggested that B.C. Hydro should have applied this test in the 69/138 kV Report. He was supported in this view by ECT Canada (T: 553). However, Mr. Saleba later conceded in cross-examination by the CAC (B.C.) et al., that the three-factor criteria used by B.C. Hydro is, in fact, consistent at the higher-principle level with the FERC criteria (T: 921).

In its cross-examination of Mr. Saleba, ZE Power Group Inc. also questioned B.C. Hydro's position that since a majority of assets meet its criteria for inclusion in the TRR, all assets should be so treated. ZE Power Group Inc. noted that part of B.C. Hydro's rationale for this approach is that markets will be changing in the coming years, and the proposed functionalization anticipates this change. Mr. Saleba appeared to agree that, notwithstanding what may be coming down the road, such anticipatory rate making would lead to over-collection of the TRR in the near-term.

CBT Power Corp. took issue with B.C. Hydro's proposition that if a line is capable of providing back-up service, then its frequency of use in that regard is irrelevant (Exhibit 5, Tab Mansour, p. 9). Instead, CBT Power Corp. argued that a line which is primarily used for other purposes should not be allocated 100 percent to transmission simply on the basis of some theoretical value to that function.

2.2.3 Alternative Proposals

As indicated in the preceding section, criticism of B.C. Hydro's proposed treatment of the 69 kV and 138 kV assets focused on two major areas: (1) treatment of generation-integration lines, and (2) functionalization of all 69 kV and 138 kV assets to transmission based on the demonstration of a majority benefit. In most cases, the proposals of intervenors build on B.C. Hydro's suggestions, but opinions divided around how to allocate the 30 percent of 69 kV and 138 kV assets that B.C. Hydro cannot demonstrate as offering a benefit to transmission.

Specifically, several intervenors advocated a cost-of-service approach to separating those 69 kV and 138 kV assets that provide a wholesale transmission function from those that do not. The former share alone, they argued, should be included in the TRR.

The Industrial Customers took the position that the Commission should follow the substance of B.C. Hydro's report until a better approach is available, but only regarding the 70 percent of assets for which a transmission benefit had been demonstrated. The remaining 30 percent, they argued, should be allocated to distribution (T: 1481).

From there, the Industrial Customers proposed that the 70 percent which B.C. Hydro identified as having a benefit to transmission should become the subject of further study. That work would be aimed at determining more precisely what portion of these assets relates to generation integration. Assets deemed to serve a generation integration function should then be treated in a manner consistent with high voltage generation integration facilities – that is, either removed from the TRR or included in it, but charged directly to B.C. Hydro Power Supply. The surviving portion of the original 70 percent would, of course, remain in the TRR.

As noted, Mr. Drazen and Ms. Pearson suggested that no line of any voltage that serves only a generation-integration function should be included in the TRR.

CBT Power Corp. supported a simple 30 percent exclusion of 69 kV and 138 kV lines from the TRR. As an alternative, however, CBT Power Corp. argues that 69 kV and 138 kV cost allocations should be made against a set of three principles:

1. Lines used for generation integration and local distribution should have their costs split on the basis of line-capacity utilization.

2. Lines used for both back-up to higher voltage lines and for local distribution should be split based on the probability of being utilized for back-up or local distribution.

3. Allocation of costs to transmission should not be based on a line's possible future use for wholesale wheeling, but should instead reflect its expected use in this regard (T: 1632).

2.2.4 Criticism of the Alternative Proposals

In its Final Argument, B.C. Hydro dismissed all alternatives raised in response to the 69/138 kV Report, stating that the criticism of this study was even more benign than that of the GRTA Comparison Report and its underlying studies (T: 1447).

Specifically, B.C. Hydro claimed that "no justification was advanced for eliminating lines that integrate local or regional generation" (T: 1447). Moreover, B.C. Hydro noted that fairness dictates including the cost of interconnection facilities for local generation in the same way that IPPs are credited for not only their cost of connection to the system, but also for the value of any benefits they add to the system as a result of their location relatively near to load.

Further, B.C. Hydro argued that even if the lines that integrate local or regional generation were eliminated, a majority of the 69 kV and 138 kV assets would still provide benefit to transmission because they parallel higher voltage lines (T: 1447).

With its Reply Argument, B.C. Hydro offered a fairly broad-brush response to intervenor suggestions that a more detailed, line-by-line cost of service analysis is needed in this area. Specifically, B.C. Hydro noted that the methodology used to analyze Lower Mainland 69 kV and 138 kV lines for the 1996 WTS hearing is the same approach that was used to analyze all 69 kV and 138 kV assets for this proceeding. B.C. Hydro argued that since the allocation of assets was accepted in 1996, it should be accepted again this time.

B.C. Hydro also addressed intervenor comments about the validity of assigning 69 kV and 138 kV assets to transmission based on their potential to back-up the higher voltage transmission system. B.C. Hydro noted that its generators receive no greater advantage from back-up systems than do other users of the system. And since the reliability benefits are shared among all users, the costs should be shared as well.

On the subject of the reliability benefits of assets that are rarely called upon to serve a back-up function, B.C. Hydro noted that the benefit of a back-up system is on-going, whether or not it is actually called into use. That the main system does not fail should not be seen to lessen the benefit provided by a secondary service option.

2.2.5 Commission Determination

The Commission observes that the studies carried out by B.C. Hydro to examine the extent to which 69 kV and 138 kV lines provide a transmission benefit meet the relevant direction contained in the June, 1996 Decision. In particular, the Commission is satisfied that against the three criteria used by B.C. Hydro in its analysis, roughly 70 percent (by distance) of 69 kV and 138 kV lines provide a transmission benefit. Further, the Commission agrees with B.C. Hydro that the frequency that a line is used for the function of backing-up the higher voltage transmission system is not relevant – insurance is not less valuable even though no claim is made against the policy.

Still, the Commission notes problems in B.C. Hydro's determination of both the 70 percent component (lines that benefit transmission) and the 30 percent component (lines that do not benefit transmission).

Specifically, the Commission notes that within the 70 percent component are lines used for generation-integration purposes. For consistency with the Commission's ruling elsewhere in this Decision regarding the GRTAs, it is appropriate that these lines should not be judged to provide a benefit to transmission.

With respect to the 30 percent component (although this share would be made larger by the addition of lines serving a generation-integration function), the Commission is persuaded by B.C. Hydro's argument that some of these lines are used by customers that take power at transmission voltage and, therefore, cannot appropriately be allocated to distribution. Similarly, that portion of the 30 percent that are generation-integration lines cannot be judged to serve a distribution function, either.

From this perspective, the Commission recognizes that the pristine approach would be to direct a cost of service analysis aimed at the no-benefit-to-transmission asset category. Presumably, this would involve a re-functionalization of these assets in a manner which included not only generation, transmission, and distribution, but some category of sub-transmission to capture those lines in the original 30 percent that provide a benefit to customers who take power at transmission voltage.

The Commission recognizes the view that not all 69 kV and 138 kV lines must be functionalized to transmission solely because a majority these lines serve a transmission function. The Commission disagrees with B.C. Hydro's assertion that expected market change and regulatory developments, which may mean that virtually all 69 kV and 138 kV lines will eventually serve a transmission function, justify functionalizing all of these lines to transmission at this time. The Commission agrees with those parties who argued that this imposes costs on WTS customers based only on assumptions about an uncertain future.

Still, the Commission wishes to be pragmatic. It recognizes that any further costing studies on the 69 kV and 138 kV assets will be time-consuming, expensive, and likely to result in an entirely new set of equity concerns. The Commission recognizes, too, that in this evolving market environment, the uses of a 69 kV or 138 kV line today may be quite different from the use of the same assets tomorrow. Expensive and detailed studies under those conditions do not seem warranted at this time. Finally, the Commission believes that the amount of money involved is comparatively small, and that accepting the known misallocations inherent in the B.C. Hydro approach is unlikely to result in any meaningful losses in system efficiency.

Therefore, the Commission directs that 100 percent of 69 kV and 138 kV assets should be functionalized to transmission. That is, these assets should be treated in a manner consistent with the interim transmission revenue requirement and interim rates now in effect.

2.3 Demand-Side Management Expenses

In its 1995 WTS Application, B.C. Hydro did not include any DSM costs in the TRR. B.C. Hydro stated that this was because DSM has only a very limited effect on either new transmission investment, or on the freeing-up of existing transmission capacity since most DSM benefits accrue to generation.

In response, the B.C. Energy Coalition (“BCEC”) argued that DSM measures provide a number of benefits to all consumers and directly benefit wheeling customers by providing transmission system stability through peak reduction and by contributing to rational system planning. Accordingly, the BCEC argued for the inclusion of some DSM costs in the TRR.

In its June 25, 1996 Decision, the Commission directed B.C. Hydro to file new rates which more precisely identified its TRR. In addition to further study on treatment of the GRTAs and low-voltage transmission assets, the Commission sought more evidence from B.C. Hydro “to determine what portion of its DSM costs can be attributed to transmission” (June 25, 1996 Commission Decision, p. 16).

2.3.1 B.C. Hydro Proposal

At the time of the June 20, 1997 filing, B.C. Hydro was operating on the premise that its Application would be disposed of by way of a Negotiated Settlement Process (the Commission announced its decision to proceed by public hearing on July 3, 1997). Accordingly, the Application dealt with this issue in a relatively brief report, entitled Allocation of DSM Costs to the Transmission Revenue Requirement ("the DSM Report"), and suggested that the issue be deferred to the Negotiation Settlement Process (Exhibit 1, p. I-AS-0-10).

The DSM Report established that the annual capitalized cost of DSM is approximately $20 million and discussed three alternative methods of allocating these costs to transmission.

The first method offered by B.C. Hydro started with the assumption that the average life of a DSM measure is 15 years. From this premise, B.C. Hydro calculated that the annualized incremental cost of serving all B.C. Hydro load is roughly $2.5 billion, of which $246 million (or 9.78 percent) reflects the costs of transmission and substations.

B.C. Hydro's second method began from the premise that demand savings from all DSM programs average 50 MW per year. Using LRIC estimates of $5/kW.yr for the main transmission system, and assuming an equal value for sub-transmission, this results in a value of $0.5 million to transmission as a result of DSM. B.C. Hydro estimated this $500,000 to be about 4 percent of total annual DSM benefits.

As a third alternative, B.C. Hydro noted that some utilities in other jurisdictions have allocated 100 percent of DSM costs to transmission – as the regulated part of the business – in an effort to ensure that socio-economic values and objectives are preserved through the shift to a competitive market.

B.C. Hydro took the position that choosing among these alternatives is a job best left to the customers. In public consultation, only the Industrial Customers offered comment, and they supported the methodology that results in the 4 percent outcome.

Based on this small value, and B.C. Hydro's belief that the inclusion of DSM costs in the TRR has broader implications for social costing, B.C. Hydro chose to eliminate all DSM costs from the TRR for this Application. This was referred to in some evidence as the *de minimus* argument (Exhibit 1, p. I-A-I-5).

2.3.2 Criticisms of the B.C. Hydro Proposal

Criticism of B.C. Hydro's DSM proposal came primarily from Bruce Biewald on behalf of the Association for the Advancement of Sustainable Energy Policy ("AASEP"), from AASEP itself, and from the CAC (B.C.) et al. Although Mr. Biewald accepted that B.C. Hydro undertook to follow the Commission's direction by attempting to estimate the portion of DSM expenditures that are related to the transmission system, he disputed the Utility's approach to developing its alternatives.

With respect to B.C. Hydro's first method, Mr. Biewald's most significant complaint was that B.C. Hydro made no attempt to identify and isolate the component of generation and bulk-transmission costs which are transmission related, instead setting this number at zero. Mr. Biewald stated that if the figure for bulk transmission that is found in the 1994 System Incremental Cost Study Update is used, a value of $109 million results. When added to B.C. Hydro's figure of $246 million for transmission-related incremental costs, this produces a total transmission-related incremental cost of $354 million or 14.6 percent of the annualized incremental non-customer related cost for serving all of B.C. Hydro's load.

Mr. Biewald was similarly unconvinced by B.C. Hydro's approach to its second method. He stated that B.C. Hydro has used $10/kW.yr while he estimates that the appropriate figure, including substations, is $47/kW.yr. From this, Mr. Biewald derived a transmission LRIC value of $2.35 million (based on B.C. Hydro's 50 MW figure), which he stated shows a DSM benefit to transmission of 14.7 percent.

AASEP offered more general comment, refuting B.C. Hydro's view that DSM costs should not be allocated to transmission now because of social costing precedents that may be improperly set. AASEP argued that the vast majority of DSM programs approved by the Commission have passed the total resource cost ("TRC") test and, therefore, are neither social programs nor recipients of a subsidy.

Further, AASEP argued that the question of whether a DSM cost is private or social is not central to the issue before the Commission. DSM expenditures have been made and, AASEP argued, these should be paid for by transmission customers to the extent that they receive a benefit from that spending. The only relevant question is how to determine the size of the benefit.

The CAC (B.C.) et al. also disagreed with B.C. Hydro's rationale for delaying decisions on allocating DSM until more is known about how electricity market reform will unfold in B.C. It noted the importance of the DSM issue, and raised the spectre of a long delay in implementing market reforms as a result of the failure of the Task Force on Electricity Market Reform to reach a consensus (or even majority) position.

The CAC (B.C.) et al. also took issue with B.C. Hydro's assertion that the consultation with the Industrial Customers alone represented a quorum among customer groups. The CAC (B.C.) et al. noted that it would not expect the views of Industrial Customers to be representative of all ratepayers.

2.3.3 Alternative Proposals

In his evidence, Mr. Biewald suggested that B.C. Hydro has been incomplete in its efforts to determine the transmission-related benefits of DSM. In particular, Mr. Biewald proposed a method he described as allocating to transmission service the full cumulative benefits that DSM provides to transmission. Beginning with a B.C. Hydro-supplied figure for total winter-1998 DSM savings of 420 MW, Mr. Biewald assumed that half of the substation costs are transmission-related (for an LRIC of $38/kW.yr) and, therefore, the transmission avoided costs are $16 million. This, he noted, is 80 percent of the annualized DSM costs.

Considering this calculation and the two B.C. Hydro approaches (adjusted for his corrections), Mr. Biewald recommended functionalizing 20 percent of DSM costs to transmission. He noted that this figure is only slightly higher than B.C. Hydro's numbers, adjusted for the corrections he suggests, and is only one-quarter the share that would be justified if the benefits of DSM to transmission were considered (Exhibit 20, p. 5).

As to the issue of B.C. Hydro's third alternative, namely allocating 100 percent of DSM costs to transmission, Mr. Biewald appears to endorse this position if generation were deregulated (Exhibit 20, p. 6).

AASEP agreed with its consultant that in a fully competitive environment, it would be necessary to collect all DSM costs through transmission in order to avoid financial disincentives for utility investment in this area. However, AASEP’s final recommendation varied slightly from that of Mr. Biewald. AASEP suggested that B.C. Hydro's 1996/97 FACOS study should be one basis for DSM allocation (the others being fairness and Mr. Biewald’s evidence). B.C. Hydro's 1996/97 FACOS study attributed DSM costs as 47.7 percent energy related and 52.3 percent capacity related. AASEP noted B.C. Hydro's position that not much beyond a simple 50:50 split drove that analysis, and AASEP argued that a similarly simple approach can be used to allocate DSM costs to the TRR (T: 711).

Specifically, AASEP recommended that, “consistent with the FACOS study”, half of the capacity of DSM should be allocated to transmission. This means that, overall, 25 percent of DSM costs would be allocated to the TRR.

The CAC (B.C.) et al. supported allocating 100 percent of DSM to the transmission revenue requirement. While the CAC (B.C.) et al. recognized that this is not consistent with the evidence of any other party in this proceeding under the current competitive circumstances, it argued that further study would be needed to get a proper functionalization figure. However, the CAC (B.C.) et al. stated that further investigation is not a productive solution at this time, given the “disappointing” study that B.C. Hydro produced in response to the 1996 Commission Direction (T: 1647).

If there is to be further study, the CAC (B.C.) et al. would like to see this contain an assessment of whether future DSM costs should be allocated across customer classes or by way of specific allocation.

The CAC (B.C.) et al. argued that utilities' DSM spending is primarily a benefit to Industrial Customers. While it acknowledged that this may be appropriate, it sought an investigation into whether benefits from DSM programs are being equitably shared.

2.3.4 Commission Determinations

All parties to this hearing appear to agree that if retail access comes to B.C., then DSM costs must remain in the regulated (i.e., transmission) part of the business, or be collected through some form of non-bypassable charge. However, given the current uncertainty about the direction of market reforms in B.C., the Commission believes that it would be inappropriate to anticipate retail competition and allocate all DSM charges to the TRR. At the same time, however, the Commission does not support B.C. Hydro's *de minimus* argument. The Commission believes that the functionalization of DSM costs will be an important issue as the market develops, and ignoring it at this stage because the monetary impacts are small would send the wrong message.

Despite Commission concerns about the wide range of outcomes in this proceeding and about the methodologies employed in all of the studies offered as evidence, the Commission declines to order further studies. Such work is unlikely to be valuable in light of probable market reforms.

Instead, the Commission has made its determination based in part on a subjective weighting of the evidence provided, and in part on its aforementioned desire to signal future policy directions.

The Commission judges that it is appropriate to allocate 10 percent of the annual capitalized DSM costs to the transmission revenue requirement. This 10 percent should not be seen as the Commission's final determination on this issue, but rather as a place holder for a value that will need to be determined as market reform unfolds. Therefore, the Commission directs B.C. Hydro to file an adjusted transmission revenue requirement and associated tariffs that reflect this judgment.

B.C. Hydro is ordered to file its adjusted revenue requirement and associated tariffs, reflecting the Commission's directions on both the GRTAs and DSM, no later than May 31, 1998.

3.0 DESIGN OF NETWORK AND POINT-TO-POINT TRANSMISSION RATES

3.1 Background

As indicated in Chapter 1 of this Decision, the tariffs put forward in this Application conform with the United States Federal Energy Regulatory Commission's ("FERC") Order No. 888-A pro forma tariff. The pro forma tariff is part of a package of policy statements and orders issued by FERC to bring into effect open wholesale transmission service within the U.S. Key statements and orders include:

1. *FERC Policy Statement concerning Pricing Policy for Transmission Services Provided by Public Utilities under the Federal Power Act, issued October 24, 1994.* This statement identifies five principles which FERC uses to evaluate wholesale transmission service tariff proposals. The five principles are: (1) the tariff must be designed to collect the traditional revenue requirement; (2) the tariff must offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of the system; (3) the tariff should promote economic efficiency; (4) the tariffs should be fair - that is, there should be no cross-subsidization between third parties and existing customers; and (5) the tariff should be practical and easy to administer.

2. *FERC Notice of Proposed Rule Making and Supplementary Notice of Proposed Rule Making ("the NOPR") issued March 29, 1995.* The NOPR addressed issues relating to the opening of access to transmission lines, including stranded assets, recommended procedures for developing wholesale transmission rates and specified initial pro forma tariffs for Network Service, Point-to-Point Service and Ancillary Services.

3. *FERC Order No. 888 - Open Access and Stranded Costs and Order No. 889 - Information Systems and Standards of Conduct issued April 24, 1996.* These Orders confirmed the NOPR with some modification. Specifically, Order No. 888 requires all public utilities that own, operate or control interstate transmission facilities, (i.e., are subject to FERC jurisdiction) to offer network and point-to-point transmission services and ancillary services to all eligible buyers and sellers in wholesale bulk power markets, and to take transmission service for their own uses under the same, rates, terms and conditions offered to others (Order No. 888-A, p. 3).

4. *FERC Notice Of Proposed Rule Making, Capacity Reservation Open Access Transmission Tariffs ("CRT") issued April 24, 1996.* The CRT NOPR proposed that each public utility replace the Open Access Rule pro forma tariff with a capacity reservation tariff by December 31, 1997.

5. *FERC Order No. 888A and Order No. 889A issued March 3, 1997.* These Orders reaffirmed the basic determinations made in Order No. 888 requiring all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to have on file open access non-discriminatory tariffs that contain minimum terms and conditions for non-service. With Order No. 888A, FERC moved away from the Capacity Reservation Tariff discussed in the April 24, 1996 NOPR.

6. *FERC Order No. 888B issued November 25, 1997.* This Order reaffirmed, with certain clarifications, the determinations made in Order No. 888A.

FERC has direct jurisdiction over U.S. utilities which engage in inter-state transmission of electricity and wholesale sales of electricity in interstate commerce. In addition, FERC has the ability to affect the tariffs of those utilities which it does not directly regulate through the establishment of standards which must be met if a non-jurisdictional utility is to have access to the transmission systems of a jurisdictional utility. FERC has stated that "the pro forma tariff (associated with Order No. 888A) is the basic mechanism implementing the requirements of comparable open access transmission" (Order No. 888A - p. 13). Further, FERC has stated that it "conditioned the use of a public utility's open access service on the agreement that, in return, it is offered reciprocal service by non-public utilities that own or control transmission facilities" (Order No. 888A - p. 16).

Based on Order No. 888A, as well as other FERC Orders, B.C. Hydro has indicated that it believes that, at this time, FERC is requiring that a non-jurisdictional utility adhere strictly to FERC's pro forma tariffs with respect to non-rate Terms and Conditions before it will grant a non-jurisdictional utility, or its marketing affiliate, access to the transmission facilities of jurisdictional utilities (Exhibit 1, p. I-AS-0-16; Exhibit 2, BCUC IR 1, Question 8). Accordingly, B.C. Hydro has stated that strict adherence to the pro forma tariff non-rate Terms and Conditions is required in order for the British Columbia Power Exchange Corporation ("Powerex") to obtain a Power Marketing Authorization ("PMA") from FERC. B.C. Hydro indicated that the value of the PMA is in the order of $100 million per year (Exhibit 1, p. I-AS-0-7).

3.2 Network Service

3.2.1 Network Service Proposal

Network Service consists of the provision of transmission service from multiple points of receipt to multiple points of delivery. As such, network transmission service allows a customer taking network service to integrate, economically dispatch and regulate its network resources to serve its network load. At present, the only network customer is B.C. Hydro Power Supply which is served under a transfer pricing agreement (General Services Agreement) that mimics the terms and conditions of network service (T: 999, Exhibit 4, Ind. IR 2, Question 5).

The previous Commission Decision with respect to wholesale transmission service directed B.C. Hydro to apply for new rates for wholesale transmission service which reflect long-run marginal costs and locational considerations and suggested that the use of regional Long-Run Incremental Costs ("LRIC") is an appropriate starting point (Decision dated June 25, 1996, p. 27). Under the terms of the current Application, customers taking network service pay their load ratio share of B.C. Hydro's Network Transmission Revenue Requirement. The Network Transmission Revenue Requirement is equal to B.C. Hydro's total Transmission Revenue Requirement less forecast revenues from Point-to-Point Transmission Service, grandfathered contracts and certain other small adjustments (Exhibit 2, BCUC IR 1, Question 35). Accordingly, it is the residual Transmission Revenue Requirement. This rate structure does not reflect LRIC price signals.

In defense of its Application, B.C. Hydro stated that it is not possible to include LRIC pricing signals in the charge for network service without requiring substantial changes to the Terms and Conditions governing network service (T: 891, Exhibit 5, Barnett, p. 6) and that such changes could result in the loss of Powerex's PMA (Exhibit 5, Fox, p. 7-8). Specifically, B.C. Hydro stated that the inclusion of LRIC price signals in the rate for network service would transform the network tariff into a capacity reservation tariff, a form of tariff which FERC had rejected (T: 70). In response to a question from the Industrial Customers, B.C. Hydro rejected the possibility of implementing network rates which reflect locational considerations but with a pre-approved reversion to the rates contained in the Application if the location based rates prove offensive to FERC, stating that it would be a significant alternative filing with little chance of success (T: 70-71).

In addition to the concerns discussed above, B.C. Hydro argued that the inclusion of LRIC pricing signals in the charge for network service is not required for efficiency purposes. Specifically, B.C. Hydro stated that as long as B.C. Hydro is the predominant user of the system, it will see the full incremental cost of any new generation located in any particular area and so will have an incentive to site new generation efficiently (T: 4575-4576).

WKP disputed the notion that pricing signals for network service are unnecessary and indicated that B.C. Hydro has not proved that the previous Commission Decision which called for LRIC based rates for network service is inappropriate (T: 1517-1518). Further, WKP rejected the idea that zones would transform the network tariff into a capacity reservation tariff, a form of tariff which FERC has rejected.

Accordingly, WKP asked that the Commission direct B.C. Hydro to develop zonal rates for network service and submit those rates to the FERC for approval (T: 1518).

3.2.2 Commission Determinations

The Commission accepts the Network Service proposed by B.C. Hydro. While the Commission would prefer to see rates for network customers which more directly incorporate appropriate pricing signals, the Commission accepts that the implementation of such rates would require substantial alterations to the non-rate terms and conditions of the FERC pro forma tariff. Given that there is only one network customer at this time, and that this customer pays the residual transmission tariff, the Commission accepts that there is a built-in incentive to minimize transmission costs. As a result, the potential loss of efficiency from approving rates which do not more explicitly reflect long-run incremental costs falls within acceptable boundaries.

3.3 Point-to-Point Service

Point-to-Point Transmission Service is for receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery. In its Application, B.C. Hydro proposes to provide three types of Point-to-Point Service: Long-Term Firm Point-to-Point, Short-Term Firm Point-to-Point and Short-Term Non-Firm Point-to-Point.

3.3.1 Long-Term Point-to-Point Service

Under B.C. Hydro's proposal, Long-Term Point-to-Point Service is available on a first come first served basis, for periods of one year or greater on a firm basis only and at the same level of priority as network service. In its February 17, 1997 filing, B.C. Hydro proposed to use a two-part rate to charge for Long-Term Firm Point-to-Point Service. The two-part rate consisted of an LRIC charge, which reflected the cost of expected transmission investment over the next ten years, and an access charge, designed to collect an appropriate share of the residual revenue requirement. However, in its June 20, 1997 Application, B.C. Hydro proposed that the two-part rate be replaced with a one-part rate in order to bring the tariff into closer conformity with the FERC pro forma and support Powerex's Application for a PMA (T: 29-30). In support of this revision, B.C. Hydro stated that the LRIC component is zero for all paths other than the Southern Interior and Alberta to the Lower Mainland/Vancouver Island so that the overall impact on efficiency of the two-part rate design is limited (Exhibit 1, p. I-AS-0-15). Further, B.C. Hydro stated that since there would be very few users of the Long-Term Firm Point-to-Point rates, only a small portion of load would receive the price signal in the two-part LRIC rate (T: 480-482). Although B.C. Hydro acknowledged that the two-part LRIC rate reflected a trade-off between the fair allocation of embedded costs based on historical decisions made by customers and the efficiency gains which could be obtained through an accurate price signal, given that only a limited number of routes have a positive LRIC and that the dollar value is low, B.C. Hydro indicated that the efficiency gains would be limited.

B.C. Hydro acknowledged the failure of embedded cost rates to signal incremental costs and induce efficient use of existing facilities or economically sound investments (Exhibit 3, BCUC IR 2, Question 9). This failure arises because the one-part rate does not discourage transmission use when there is a capacity shortage nor encourage use when there is idle transmission capacity (Exhibit 5, Orans, p. 7). To overcome this failure, B.C. Hydro proposed that under certain circumstances, the Long-Term Firm Point-to-Point rate would be discounted. Specifically, B.C. Hydro proposed that long-term discounts be considered wherever a discount is necessary to encourage new generation or load to locate in a manner that would increase the overall efficiency of the system. Accordingly, B.C. Hydro stated that siting generation in areas which yield cost effective reductions of losses or permit deferral of transmission investment would be considered for discount (Exhibit 3, BCUC IR 2, Question 9). At the same time, B.C. Hydro noted that the efficiency benefits gained through discounting have to be weighed against potential lost net revenue that could occur because of the need to provide discounts to all unconstrained transactions going to the same Point of Delivery. Accordingly, B.C. Hydro stated that it intended to discount firm Long-Term Point-to-Point service rates only when the discount would result in use of the system which would not otherwise occur and the increased use would result in a positive contribution to the revenue (Exhibit 3, BCUC IR2, Question 9).

During the hearing, B.C. Hydro attempted to distinguish its discounting proposal from the idea of providing system credits. B.C. Hydro stated that system credits are the potential benefits to B.C. Hydro's transmission system caused by the addition of new generation and include the potential deferral of planned transmission projects for both the bulk and the local system of lower voltages and energy savings due to reduced losses. B.C. Hydro stated that to ensure accuracy, system benefits must be calculated on a case-by-case basis using the facility's studies required for new interconnections (T: 419). In contrast, B.C. Hydro stated that discounts are not related to system benefits but are related to enhancing the utilization of the transmission system (T: 419). B.C. Hydro stated that as long as capacity is available, the marginal cost of providing transmission is practically zero. Therefore, offering discounts to encourage longer-term transactions that provide positive contribution to margin is desirable since it would lower rates for all customers (T: 422).

Although B.C. Hydro stated that the specific criteria with respect to discounting Long-Term Point-to-Point rates would be developed after consideration of the policy by the Commission and consultation with customers, B.C. Hydro indicated that discounts would most likely be allowed only where service is for greater than five years. Specifically, B.C. Hydro proposed that upon application of a generator for firm transmission for a period in excess of five years, B.C. Hydro would post the quantity, specific point of delivery and price on the Open Access Same Time Information System ("OASIS"). Any party nominating within 30 days (the "Open Season") to take transmission to the point of delivery for that term and price would be considered as part of the Open Season discount group. At the close of the Open Season, B.C. Hydro would evaluate the total proposed nomination of the group and determine whether the objectives of its discount policy would be served by giving a discount to the group and the extent of any transmission savings which the location of the proposed generator might provide to the network. If the objectives of the discount policy were met, after taking into account the discount being given to the Group on the one hand and the transmission savings being introduced by the new generator on the other, the discount would be given to all members of the group. Once the open season is closed, no further discounts would be given without a new open season being held (Exhibit 5, Orans, p. 9-10).

Several parties expressed concern with respect to the discount policy. The Industrial Customers suggested that the discount policy proposed by B.C. Hydro is undefined in that an IPP would not know how to calculate what the discount might be (T: 59) and, because it would be known in advance, that a siting credit would give a clearer signal to independent generators of the impact of locating new generation in a particular location (T: 60, T: 1482). Further, the Industrial Customers stated that it appears that B.C. Hydro's intent is to minimize the discounting policy whenever possible, unless the discount would increase the use of the transmission system (T: 1482).

ZE Power Group Inc. also expressed concern that, under the proposed discounting policy, IPPs would not know the amount of discount they could obtain and so could not use discount information to facilitate siting decisions. In addition, ZE Power Group Inc. expressed concern that information which the IPP passes on to B.C. Hydro Transmission to determine the discount might be passed on to B.C. Hydro Generation. Finally, ZE Power Group Inc. expressed concern that any discounting would be subjective and that B.C. Hydro might withhold a discount if it meant that an IPP receiving a discount would be more competitive than B.C. Hydro generation (T: 1709). Accordingly, ZE Power Group Inc. called upon the Commission to direct B.C. Hydro to file the discount with the Commission in a tariff like form (T: 1710).

In response to these concerns, B.C. Hydro indicated that parties are mistaken if they believe that negotiations with B.C. Hydro would be required before receiving a discount. Instead, B.C. Hydro indicated that any party wishing a discount could arrange to have its proposal posted on OASIS. After the open season is conducted, B.C. Hydro stated that Grid Operations would evaluate what proposals for discounted transmission to the point of delivery in question had been forthcoming and how the revenue collected from those transactions at the discounted price compare with the revenue which would be collected from anticipated transactions at full rates (T: 1753).

Further, B.C. Hydro stated that discounts would be given in addition to location credits that reflect customer contribution to relieving or avoiding local transmission constraints. B.C. Hydro stated that location credits are not available on the bulk system because the LRIC studies do not provide a basis for giving location credits on an across the board basis (T: 1755). B.C. Hydro did not explain under what circumstances location credits would apply.

Although the B.C. Hydro June Application proposes a one-part Long-Term Firm Point-to-Point rate, and the Utility has made it clear that this is the rate structure which it prefers, in its opening statement the Utility indicated that it has developed tariff language which it thinks will permit the implementation of a two-part LRIC rate without endangering Powerex's Power Marking Authorization. Accordingly, B.C. Hydro has asked that, if the Commission still believes that there is merit in pursuing the two-part LRIC rate, the Commission explicitly accept both rate forms for filing, with the LRIC rate being in effect until and unless the Utility provides evidence that maintenance of the two-part rate form would jeopardize access to U.S. transmission (T: 32-34). At that time, with the Commission's explicit permission, the Utility would withdraw the two-part LRIC rate and revert to the one-part rate without further public process (T: 249-251). B.C. Hydro acknowledged that it knows of no precedent for this Reversionary Rate Proposal (T: 250).

As was the case with the February filing, the proposed two-part LRIC rate consists of a flat access charge and an LRIC charge based on regional points of receipt and regional points of delivery. For paths other than from Alberta and the Southern Interior to the Lower Mainland, Vancouver Island and the Bonneville Power Administration, the LRIC charge is zero. For the congested routes, the LRIC charge is $0.42 per kW/month and reflects the expenditures required in the next ten years to reinforce and expand B.C. Hydro's transmission lines to reliably service B.C. Hydro's customers at least cost (Exhibit 5, Orans, p. 14). B.C. Hydro stated that the two-part LRIC rate collects only the Utility's embedded cost Transmission Revenue Requirement (Exhibit 5, Orans, p. 13) and is unlikely to be viewed as a form of 'and' pricing prohibited by FERC. B.C. Hydro also indicated that it would maintain the discount procedure discussed above, even if the two-part rate were implemented.

B.C. Hydro indicated that it does not view a similar option as being available to Network Service since, as discussed above, it would require substantial changes to the terms and conditions associated with the FERC pro forma.

Several parties suggested that there is a need for more explicit pricing signals than are embodied through the discount policy. WKP stated that pricing for transmission service should provide price signals that achieve economic efficiency while also fairly recovering the transmission revenue requirement (Exhibit 27, p. 16). However, as B.C. Hydro's proposed rates use a postage-stamp structure, WKP stated that the efficient siting of generation from a transmission perspective would not be encouraged

(Exhibit 27, p. 16). Instead, WKP suggested that B.C. Hydro should provide distance based transmission rates such as MW-mile or zonal rates (Exhibit 27, p. 17). This was echoed by the Industrial Customers who called for short-haul rates (T: 1486). WKP argued that zonal rates with congestion pricing would lead to efficiency gains and is a fairer method of recovering the Transmission Revenue Requirement (Exhibit 27, p. 17), although WKP conceded that to the extent these rates are based on embedded historical costs they would be unlikely to provide efficient price signals (T: 960).

In the absence of acceptance of WKP's proposal, WKP's witness indicated that there might be some merit to the proposed two-part rate as long as the long-run incremental cost component is not imposed on a customer until there is a transmission constraint (T: 926).

CAC (B.C.) et al. also supported the introduction of a two-part rate but recommended that B.C. Hydro be directed to conduct an ongoing investigation into the possibility of introducing zonal pricing. CAC (B.C.) et al. also recommended that B.C. Hydro be directed to actively monitor developments in other jurisdictions so as to further encourage proper locational price signals for new generation investment and to ensure consistency with industry practice. (T: 1648)

Although most of the debate with regard to Long-Term Point-to-Point rates centred on the discount policy and the relative merits of the one- versus two-part rate, the Industrial Customers also expressed concern with respect to the way in which the Long-Term Point-to-Point rate is set and billed. Customers wishing to take Long-Term Firm Point-to-Point Service must identify specific Points of Receipt and Delivery at which they reserve capacity and are billed based on their maximum use at either the Point of Receipt or Point of Delivery. The maximum rate is equal to B.C. Hydro's total Transmission Revenue Requirement less Short-Term Point-to-Point Revenues, revenues from grandfathered contracts and certain other adjustments divided by the annualized maximum system non-coincident peak (Exhibit 2, BCUC IR 1, Question 36).

The Industrial Customers stated that the transmission system is made up of two types of facilities: local facilities and deep or bulk transmission facilities. The Industrial Customers argued that the sizing of local transmission facilities is determined by the maximum demand that must be served at the point of receipt or delivery, whereas bulk transmission facilities are characterized by common usage and therefore the cost is driven more by coincident demand.

The Industrial Customers argued that it is inappropriate to bill point-to-point transmission customers on the basis of non-coincident demand when B.C. Hydro’s use of the system for its end-use customers is effectively billed on the basis of the monthly network load coincident with the system peak (T: 1486). The Industrial Customers suggested that true billing equality requires that B.C. Hydro calculate the rate and charge itself on the same non-coincident basis for its use of the local portion of the transmission system as it charges others. Accordingly, the Industrial Customers asked that the BCUC direct B.C. Hydro to separate the cost of its transmission system into local and bulk facilities and bill separately for their use.

In response to these concerns, B.C. Hydro stated that the identification of transmission facilities as either local or bulk transmission facilities would be difficult and would add to the complexity and contentiousness of the functionalization of its facilities (T: 1803). Further, B.C. Hydro maintained that such a separation would have no impact in a world in which only wholesale transmission access is allowed. Nonetheless, B.C. Hydro indicated a willingness to study the issue with Industrial Customers if retail access were implemented.

3.3.2 Commission Determinations

In its previous WTS Decision, the Commission stated that there is a need to develop more efficient pricing signals than those which are contained in the proposed B.C. Hydro rates and explicitly rejected B.C. Hydro's argument that locationally efficient price signals are not needed until such time as transmission constraints occur. Accordingly, the Commission directed B.C. Hydro to apply for new rates for wholesale transmission service which reflect long-run marginal costs and locational considerations.

In the current Application, B.C. Hydro has applied for complete relief from this direction or, failing that relief, a guarantee by the Commission that such relief will be forthcoming if rates which reflect long-run incremental costs and locational considerations adversely affect Powerex's PMA. In asking for this relief, B.C. Hydro has reiterated the argument presented at the last hearing, specifically that there is little or no benefit to be gained in the near term from locationally efficient prices. In addition, B.C. Hydro has argued that whatever efficiency would be otherwise encouraged by the two-part rate can be gained through means of the discount policy discussed above. Finally, B.C. Hydro has added its concern that the implementation of a two-part rate could cause Powerex's PMA to come into jeopardy, either because it causes changes to the Terms and Conditions associated with this tariff which are offensive to FERC or because the two-part rate is seen as being an offense against FERC's prohibition against 'and' pricing.

Based on the evidence and argument presented with respect to this Application, the Commission continues to believe that rates which incorporate efficient locational pricing signals are beneficial and, in the absence of compelling offsetting reasons, should be encouraged. Therefore, the question before the Commission is, do such compelling offsetting reasons exist?

It is clear to the Commission that, under the current rate setting procedures, if Powerex were to lose its PMA, rates to all customers would increase. Further, based on the evidence in this hearing, it is likely that if the PMA were lost, the impact on rates could be substantial. Accordingly, the Commission accepts that in this instance priority must be given to safeguarding the PMA. The question then becomes to what extent can locationally efficient pricing also be achieved.

In an effort to be responsive to the Commission's strong commitment to establishing locationally efficient pricing, B.C. Hydro has put forward its Reversionary Rate Proposal. Although at first glance this proposal would appear to solve the Commission's current dilemma, the Commission is concerned that it would merely postpone the problem. Given that the Commission would not wish to wait until the PMA was lost before it allows the reversion, it is not clear to the Commission the basis upon which it would establish that reversion is required. Further, the Commission is concerned that it would establish a regulatory precedent which may not be appropriate. Accordingly, the Commission reluctantly rejects the Reversionary Rate Proposal.

Therefore, the Commission approves the one-part rate put forward by B.C. Hydro subject to any adjustments which must be made as a result of determinations made elsewhere in this Decision. In addition, the Commission directs B.C. Hydro to file a Petition for Declaratory Order with FERC, within 90 days of this Decision, asking that it formally rule on the acceptability of the two-part rate as set out in the Reversionary Rate Proposal. If it becomes clear, either through the Petition for Declaratory Order or through other means, that the implementation of locationally efficient rates would not lead to the loss of the PMA, the Commission intends to move expeditiously to see that rates which reflect locationally efficient prices are implemented.

With respect to the discount policy proposed by B.C. Hydro, the Commission has several concerns. First, the Commission is concerned that the evidence indicates that the objectives of the discount policy are unclear. At certain places, B.C. Hydro appears to indicate that the over-riding objective of the discount policy is to encourage use of idle transmission capacity if such use would lead to an increase in margin (T: 419, 422). As such, B.C. Hydro appears to indicate that the criteria for offering a discount are that the short-to medium-run incremental costs of transmission use be low and that the demand for the group of customers participating in the discount be elastic, i.e., that the revenue gains from the increased load be enough to offset the loss of revenue from the reduction in the rate for load that would use the transmission even if the rate were not discounted. Accordingly, B.C. Hydro appears to be differentiating this criterion from a system benefit criterion. However, elsewhere, B.C. Hydro indicates that long-term discounts be considered wherever a discount is necessary to encourage new generation or load to locate in a manner that would increase the overall efficiency of the system, either by reducing system losses or permitting deferral of transmission investment (Exhibit 3, BCUC IR 2, Question 9). This criterion appears to relate more to long-run incremental costs and is not easily distinguishable from system benefits. Given this apparent inconsistency, it is not easy to determine how customers applying for a firm WTS discount would comply with B.C. Hydro's requirement that the customer provide proof that the discount conforms with the objectives of the discount policy.

Second, the discount policy requires that all proposed discounts be evaluated on a case-by-case basis to ensure that the objectives of the discount policy are met. Although the Commission recognizes that such a policy protects the revenue requirement, it also means that the discount policy is vulnerable to charges of subjectivity. In addition, the requirement that all proposed discounts be evaluated on a case-by-case basis, means that a party considering an investment in an independent power project would not know in advance what the transmission charge for the project would be. This would add another level of complexity to the evaluation of independent power projects.

Third, under the B.C. Hydro proposal, if a discount to a particular point of delivery is allowed, the discount would only be available to those customers who participated in the Open Season. While the Commission is cognizant that this limitation also acts to protect the revenue requirement for the benefit of all customers, the Commission is concerned that it may result in potentially unduly discriminatory rates. Under B.C. Hydro's proposal, customers accessing the same point of delivery could pay different rates based solely on the time at which they began using the point of delivery. The Commission would need to be assured that the discrimination involved in this proposal is not undue.

Given the concerns discussed above, and B.C. Hydro's own evidence that it does not expect significant use of the Long-Term Point-to-Point rates in the near term, **the Commission does not approve the discount policy as put forward in this Application. Nonetheless, the Commission believes that if the concerns discussed above can be resolved, discounting may provide benefits which would accrue to all customer classes. Accordingly, the Commission directs B.C. Hydro to consult with its customers, both those who may use the WTS rates directly and those who will be affected by its use, in an effort to establish a discount policy, or some other policy, which will encourage the efficient present and future use of the transmission system and respond to the Commission's concerns as outlined above. This policy should distinguish between the benefits to be gained from discounts from those to be gained from site credits. B.C. Hydro is directed to file this new policy with the Commission no later than October 31, 1998.**

With respect to the concern raised by the Industrial Customers regarding local and bulk facilities, the Commission accepts that in the current environment in which only wholesale transmission access is allowed and in which B.C. Hydro Power Supply is the only network customer and pays the residual transmission revenue requirement, the identification of local and bulk facilities for billing purposes is unlikely to have any significance. The Commission is concerned that in an environment in which real or virtual retail access is allowed, the more precise identification of local and bulk facilities is required if true billing equity between B.C. Hydro and its transmission customers is to be achieved**.** In addition, the Commission recognizes that the distinction between local and bulk facilities may be relevant to the future identification of GRTAs, the issue dealt with in Chapter 2 of this Decision. **Accordingly, the Commission directs B.C. Hydro to work with Industrial Customers to bring forward a proposal for separating local and bulk facilities for billing purposes and for the possible future identification of GRTAs by October 31, 1998.**

3.3.3 Short-Term Point-to-Point Service

Short-Term Point-to-Point Service is available on both a firm and a non-firm basis for periods of up to one year. As set out in B.C. Hydro's Discount Policy, the purpose of short-term service is to promote energy trading. Accordingly, B.C. Hydro plans to price short-term service to capture a fair portion of the economic gain from short-term electricity trade, which B.C. Hydro suggests can be measured as the difference between wholesale market price indices (Exhibit 3, BCUC IR 2, Question 9). In most cases, B.C. Hydro suggests that the gains from trade can be measured by the difference in price between the Alberta Energy Company “C” hub ("AECO") spot market gas price, adjusted to reflect the different heat rates between electricity and natural gas, and the California-Oregon Border ("COB") price, divided by the number of participants to the trade, usually four. However, if circumstances suggest that the formula will not deliver an appropriate price for a particular trade, B.C. Hydro will use a different method of establishing the price.

In its Application, B.C. Hydro recognized short-term firm service gives a higher quality of service than short-term non-firm service. Accordingly, B.C. Hydro proposed to price non-firm service at the market proxy calculated as described above and firm service at the market proxy plus a flexible premium. In no case is the price for non-firm service to be less than 1 mill nor less than 2 mills for firm service. For both firm and non-firm service, the price is capped at the firm Long-Term Point-to-Point rate. In all cases, B.C. Hydro proposes to post the price on OASIS and otherwise follow FERC's discount policy.

The Commission accepts B.C. Hydro's proposal with respect to Short-Term Point-to-Point Service.

3.4 Ancillary Services

3.4.1 General

B.C. Hydro defines Ancillary Services as those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations. All Transmission Customers must arrange for

Ancillary Services which are provided by both generators and the bulk transmission system (Exhibit 1, p. I-B-1).

In its Application, B.C. Hydro proposes to offer seven Ancillary Services: (i) Scheduling, System Control and Dispatch; (ii) Reactive Supply and Voltage Control; (iii) Regulation and Frequency Response; (iv) Energy Imbalance Service; (v) Operating Reserve - Spinning Reserve Service; (vi) Operating Reserve - Supplemental Reserve Service; and (vii) Real Power Losses and Loss Compensation Transmission Service. Of the seven Ancillary Services, Scheduling, System Control and Dispatch, Regulation and Frequency Response, and Reactive Supply and Voltage Control must be purchased from B.C. Hydro (Exhibit 1, Schedules 3003, 3004, 3005), although customers who can demonstrate that they don't require the latter service will not be required to purchase it (Exhibit 5, Harrington, p. 2-3).

B.C. Hydro Transmission and Distribution indicated that where the Ancillary Services are generation related, it intends to purchase these services from B.C. Hydro Power Supply for resale to end-use customers. Both ZE Power Group Inc. (T: 1715) and the Large Industrial Customers expressed concern that B.C. Hydro Transmission and Distribution has not allowed for the opportunity for competitive procurement of these ancillary services. In response, B.C. Hydro indicated that it believes that B.C. Hydro Power Supply is the lowest cost provider of the services (T: 1244-1245). Further, where it is technically possible for a generator other than B.C. Hydro Power Supply to supply the ancillary service, a transmission customer is free to make arrangement to acquire those services from the other generator (T: 1246-1248).

In addition, the Industrial Customers argued that B.C. Hydro Power Supply should be required to pay for ancillary services on the same basis as any other customer buying ancillary services from B.C. Hydro Transmission and Distribution (T: 1484).

In response to this complaint, B.C. Hydro indicated that, with the exception of those services which only B.C. Hydro Transmission and Distribution could provide, all customers have the option to self-supply ancillary services. Accordingly, B.C. Hydro maintained that B.C. Hydro Power Supply is being treated on the same basis as any other wholesale transmission customer.

The Commission accepts that B.C. Hydro Power Supply is being treated on the same basis as other wholesale transmission customers.

3.4.2 Energy Imbalances

Of the seven ancillary services offered by B.C. Hydro. only two came under particular scrutiny at the hearing. These are: (i) energy imbalance service; and (ii) loss compensation service.

An energy imbalance occurs when load under contract from a specific generator either exceeds or fails to take all of the generator's deliveries into the system, after adjustment for energy losses. In its Application, B.C. Hydro proposes to offer transmission customers a service such that when this occurs, B.C. Hydro will adjust its own generation according to conditions and rates set out in Rate Schedule 3006. Specifically, for those customers taking the service, B.C. Hydro proposes to establish a deviation band of ± 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of a transmission customers' scheduled transactions. Under the proposal, parties would attempt to eliminate the energy imbalances that lie within the ± 1.5 percent band within 30 days. However, imbalances which lie outside the band, or which are not eliminated within 30 days, would attract either a charge or a credit as applicable. For positive imbalances within the bandwidth not eliminated within 30 days the credit would be equal to B.C. Hydro's minimum monthly cost of purchasing energy. If B.C. Hydro did not purchase energy during the month, the previous minimum price would be used. If a B.C. Hydro system spill occurs during the month there will be no credit. Positive hourly imbalances outside the ± 1.5 percent band will be forfeited.

For negative imbalances that fall within the band and are not eliminated within 30 days, an energy imbalance charge of $0.02599 per kW.h would apply. For any negative imbalances outside the band, the energy imbalance charge is proposed to be 1.25 times the per kW.h charge.

The above proposal differed from the proposal made by B.C. Hydro in its 1995 Application as modified by the Commission's 1996 Decision. As a result of the 1996 Commission's Decision, B.C. Hydro was directed to offer energy imbalance service under two sets of conditions. If a customer took load following service (now referred to as Regulation and Frequency Response Service) from B.C. Hydro, the energy imbalance provisions allowed for a bandwidth of ± 5 percent on a monthly basis and ± 10 percent on an hourly basis. If a customer did not take load following service from B.C. Hydro, the ± 1.5 bandwidth applied.

In requesting the change to the previous Commission direction, B.C. Hydro indicated that FERC objects to linking energy imbalance charges to whether a customer takes Regulation and Frequency Response Service from the Utility so that maintaining the link could put the PMA in jeopardy.

The Industrial Customers expressed concern that the level of credit for positive imbalances is too low when compared with the charge for negative imbalances (Exhibit 37, p. 30) and that the asymmetry between positive and negative imbalance charges is inappropriate on the basis of both fairness and efficiency and puts independent suppliers at a disadvantage relative to B.C. Hydro (T: 1483). In response, B.C. Hydro stated that positive imbalances also impose a cost on B.C. Hydro's system since it could cause B.C. Hydro to spill power at certain times and increases uncertainty for the control area operator (T: 1099-1100) so that the asymmetric treatment is appropriate. Further, B.C. Hydro indicated that a review of the evidence shows that many utilities charge asymmetrically for positive and negative imbalances (T: 1428). As a result, B.C. Hydro urged the Commission to accept the modifications proposed in the Application.

3.4.3 Commission Determination

The previous Commission Decision allowed for a more generous treatment of energy imbalances in those cases where a customer purchases Load Following Service from B.C. Hydro. Although the Commission accepted the linkage between Rate Schedules in the previous Decision, on the basis of the evidence now before it, the Commission has determined that all services should be treated and priced on an independent basis. Accordingly, the Commission accepts the offering of a single energy imbalance service based on a 1.5 percent bandwidth.

In its previous Decision, the Commission allowed for the asymmetric treatment of energy imbalances on the grounds that positive imbalances may impose costs as well as provide potential benefits to B.C. Hydro. With respect to this element of the Commission's previous decision, namely the asymmetric treatment of energy imbalances, the Commission does not find that the Industrial Customers have provided a sufficient basis for the Commission to find that the asymmetric treatment of energy imbalances should be eliminated. **The Commission accepts B.C. Hydro's proposal with respect to energy imbalances, as set out in the Application.**

3.4.4 Incremental Losses

In the 1996 Decision, the Commission directed B.C. Hydro to estimate the losses for wholesale transmission based on an Incremental Loss Factor, updated on an on-going basis, and to compensate a wholesale transmission customer if it could be shown that losses on the system were reduced because of the customer's transaction. In its Application, B.C. Hydro asked that the Commission allow the Utility to adopt the industry standard Loss Compensation charge based on system average losses instead of incremental losses. By using system average losses, instead of incremental losses, the Utility would no longer be required to compensate customers whose transactions reduced system losses.

B.C. Hydro based its request on two reasons. First, B.C. Hydro stated that it believes the use of incremental losses would violate FERC's policy that average losses are required when rates reflect average embedded costs. If B.C. Hydro were to implement incremental losses while charging rates based on average embedded costs, B.C. Hydro stated that Powerex's PMA would be threatened (Exhibit 5, Fox, p. 16).

Second, B.C. Hydro stated that maintaining incremental losses is not in the interest of British Columbians. B.C. Hydro stated, that if it were to use incremental losses while other transmission systems used by Powerex used average losses, it would result in revenues being transferred from B.C. Hydro to other transmission system operators. As well, although the use of incremental losses should result in more economically efficient dispatch of resources, B.C. Hydro maintained that because B.C. Hydro's generation would continue to be dispatched as the low cost resource, under either an incremental or average loss scenario, there would be no increase in efficiency (Exhibit 5, Orans, p. 20-21).

With respect to B.C. Hydro's first argument, the Bonneville Power Administration argued that B.C. Hydro could use incremental losses in conjunction with rates based on average embedded costs without threat to Powerex's PMA. While BPA recognized that B.C. Hydro is required to conform to the pro forma non-rate terms and conditions if it wishes to comply with FERCs reciprocity conditions and safeguard Powerex's PMA (T: 1592), BPA stated that as a non-jurisdictional utility, B.C. Hydro is not required to follow FERC's ratemaking practices (T: 1593). BPA maintained that FERC views losses as a rate issue and therefore a direction to B.C. Hydro to use incremental rates is unlikely to have an impact on the PMA (T: 1591). Further, BPA stated, that even for jurisdictional utilities, FERC's policy with respect to losses is evolving so that it is unlikely that FERC would automatically reject the use of incremental losses with average costs (T: 1606).

With respect to B.C. Hydro's second argument, BPA stated that maintaining incremental losses as directed in the previous Decision is in the interest of British Columbians for several reasons. BPA stated that imports scheduled against the prevailing flow on the B.C. Hydro system could result in reduced system losses. In addition, using incremental losses would ensure that the impact on average system losses is taken into account when developing additional remote hydroelectric generation. As well, use of incremental losses could reduce the costs of imports to B.C. and allow prices to B.C. consumers to decline. Finally, the use of incremental losses would preserve the economic signal provided by incremental loss factors regarding the costs of sales to the U.S. versus the cost of sales to Alberta (T: 1611).

In addition to supporting BPA's arguments regarding the acceptability of incremental losses to FERC (T: 1728), Enmax argued that B.C. Hydro's stand against incremental losses ignores interconnections in Canada, particularly B.C. Hydro's interconnection with Gridco. Enmax argued that because Gridco offers incremental losses, B.C. Hydro would offend against FERC's comparability rule if it uses average losses in its dealings with Gridco.

In response to these arguments, B.C. Hydro stated that not one of the 166 FERC jurisdictional utilities has been permitted to use an incremental loss factor in conjunction with embedded cost postage-stamp rates and no non-jurisdictional utility has attempted to deviate from FERC's policy with respect to incremental losses. In addition, the use of average system losses is the industry standard; if B.C. Hydro uses incremental losses while BPA continues to use average losses, it would result in B.C. Hydro transferring revenue to BPA. Further, B.C. Hydro argued that it is not feasible to apply incremental losses to network service and that if it applies incremental losses to Point-to-Point service, without applying incremental losses to network service, it runs the risk that it would trigger FERC concerns over comparability and non-discrimination. Finally, B.C. Hydro argued that if it tries to offer incremental losses only to those parties who offer it incremental losses, it would be necessary for B.C. Hydro to amend the non-rate terms and conditions of its tariff dealing with the reciprocity requirement. B.C. Hydro suggested that this would likely be unacceptable to FERC. (T: 1757-1758).

3.4.5 Commission Determinations

As set out in several other Commission Decisions, the Commission views its primary duty as being the protection of rate payers. With respect to incremental losses, the Commission is convinced that, all other things being equal, incremental losses provide greater rate payer protection than do average system losses since they provide a better signal as to the most desirable location for generation. Therefore, if B.C. Hydro operated within a closed system, the Commission would have no hesitation in confirming the determinations with respect to incremental losses contained in the previous Commission Decision.

However, B.C. Hydro does not operate in a closed system. Instead, it is an active participant in the larger western North American electricity market in which the industry standard is average losses. The evidence before the Commission suggests that maintaining the direction to employ incremental losses puts B.C. Hydro at a disadvantage vis-a-vis certain of the utilities with which it interconnects. Indeed, the evidence suggests that the effect of maintaining incremental losses would be to transfer revenues from B.C. Hydro to other utilities. When coupled with the evidence as to the unacceptability of incremental losses to FERC when average embedded cost rates are used, such that the use of incremental losses could lead to the loss of the PMA, it is difficult to determine that incremental losses would be in the best interest of rate payers.

Accordingly, the Commission must trade off the two impacts of incremental losses described above to determine what decision will best protect rate payers. Given the evidence before the Commission with respect to the likelihood of new generation and transmission investment, the Commission finds that rate payers are best protected if B.C. Hydro employs average system losses.

Therefore, the Commission accepts B.C. Hydro's proposal with respect to loss compensation.

4.0 TERMS AND CONDITIONS

As was the case in the 1996 WTS hearing, much of the focus of this hearing concerned the determination of the transmission revenue requirement and the form of the rates used to collect the requirement. However, certain parties did express concern with respect to the Terms and Conditions proposed by B.C. Hydro. Most of the concern focused on two areas: (i) the relationship between B.C. Hydro Transmission and Distribution ("B.C. Hydro T&D") and B.C. Hydro Power Supply and Powerex, and (ii) the allocation of capacity on the B.C. - Alberta intertie.

4.1 The Relationship between B.C. Hydro Power Supply, Powerex and B.C. Hydro T&D

During the previous hearing, there was significant discussion concerning the relationship between B.C. Hydro T&D and B.C. Hydro Power Supply and Powerex. Generally, the concerns fell into two areas: would B.C. Hydro T&D apply the proposed tariffs to B.C. Hydro Power Supply and Powerex on the same or comparable basis as they were applied to third parties using the system, and was the Code of Conduct put forward by B.C. Hydro to govern the relationship between B.C. Hydro T&D and Power Supply and Powerex sufficient to ensure that Power Supply and/or Powerex would not receive an advantage from the fact that they were affiliated with B.C. Hydro T&D?

In response to these concerns, the previous Commission Decision directed B.C. Hydro to apply all the Terms and Conditions of the Network and Point-to-Point Services to itself except where to do so was patently unreasonable. In those cases, where B.C. Hydro felt the application was unreasonable, the Commission directed B.C. Hydro to apply to the Commission for relief from the provisions and state specifically which conditions should not apply and why they should not apply (Decision dated June 25, 1996, p. 48).

Although B.C. Hydro indicated that it does apply all the Terms and Conditions to itself through the General Service Agreement except where it has been granted specific relief by the Commission (T: 79), some parties continued to express concern about the relationship between B.C. Hydro Power Supply and Powerex and B.C. Hydro T&D.

Enron Capital and Trade Corporation ("ECT Canada") argued that the direction contained in the previous Decision is insufficient and does not adequately protect customers against the potential for B.C. Hydro T&D to favour its affiliates by providing them with preferential access to information or by engaging in discriminatory behavior (T: 1532). ECT Canada argued that a level playing field requires the complete separation of commercial functions from functions required for the reliable physical operation of the transmission system and that this could best be accomplished through de-integration of the transmission function from the utility and the introduction of an Independent System Operator (T: 1532). Similarly, both WKP and ZE Power Group Inc. called for the creation of an ISO or, if this were not within the Commission's power to effect, the creation of a Grid Oversight Committee along the lines envisioned in the recent Report of the Task Force on Electricity Market Reform (T: 1712, T: 1525).

In the absence of the above, ECT Canada argued that the current safeguards put in place to protect ratepayers need to be improved (T: 1535). ECT Canada identified two areas where it stated the safeguards need to be strengthened. These are: (i) the commitment to comply with OASIS procedures and (ii) the internal Code of Conduct for Grid Operations and Inter Utility Affairs.

ECT Canada acknowledged that Tariff Supplement No. 30, requires B.C. Hydro to "follow North American industry standard terms and conditions (including those prescribed for U.S. electric utilities by the FERC) and Commission requirements (including standards of conduct) in implementing, operating or utilizing the OASIS". However, ECT Canada maintained that such implementing, operating and utilizing of OASIS must be done in a manner consistent with the most current Standards and Protocols issued by FERC. Accordingly, ECT Canada asked that the Commission make a specific direction to B.C. Hydro that it is to comply with the current Standards and Communication Protocols for OASIS as may be issued by the FERC from time to time except where to do so is patently unreasonable. In the event that B.C. Hydro believes such compliance to be unnecessary or unreasonable, ECT Canada stated that B.C. Hydro should be required to apply to the Commission for relief from such compliance and that the application should state specifically which Standards and Communications Protocols should not apply and why they should not apply (T: 1536).

In addition, ECT Canada stated that the current Code of Conduct, which formed part of the record of the last hearing, is deficient vis-a-vis industry standards for similar codes of conduct. In particular, ECT Canada indicated that it is concerned that the current Code does not include a procedure for reporting violations of the Code of Conduct to the BCUC (T: 1537).

ECT Canada rejected B.C. Hydro's argument that FERC has endorsed B.C. Hydro's Code of Conduct. ECT Canada stated that FERC only did a cursory review because of its limited jurisdiction over transactions with affiliated utilities in foreign jurisdictions. ECT Canada stated that FERC simply observed that restrictions contained in the Code were similar to those required by FERC but did not analyze the Code or discuss mechanisms in place to oversee compliance (T: 1538).

Specific examples of deficiencies cited by ECT Canada include:

1. The lack of a BCUC directive that employees engaged in transmission system operations must function independently of employees engaged in wholesale merchant functions.

2. The lack of any standards relating to the transferring of employees between transmission system operations and wholesale merchant functions and a requirement that notice of such transfers be posted on OASIS.

3. The lack of a BCUC directive that employees engaged in wholesale merchant functions are prohibited from having preferential access to any information about the transmission system that is not available to all users of an OASIS.

4. The lack of a BCUC mandated procedure in the event that an employee of the transmission provider discloses information not posted on OASIS in a manner contrary to the standards of conduct.

5. The lack of a BCUC directive that the transmission provider must apply all tariff provisions relating to the sale or purchase of open access transmission service in a fair and impartial manner that treats all customers in a non-discriminatory manner if these provisions involve discretion.

6. The lack of a BCUC directive that the transmission provider keep a log, available for BCUC audit, detailing the circumstances and manner in which it exercised its discretion under any terms of the tariff.

7. The lack of a Commission directive that the transmission provider not give preference to any wholesale customer over another, including discounts on transmission services or ancillary services, unless such discount is made available to all transmission customers

8. The lack of a BCUC directive that the transmission provider maintain its books of account and records separately from those of its affiliates and that they be available for BCUC inspection.

9. The lack of a BCUC directive that the transmission provider maintain in a public place, and file with the BCUC, current written procedures implementing the standards of conduct in such detail as will enable customers and the BCUC to determine that the transmission provider is in compliance with the requirements of the code of conduct (T: 1543-1545).

As a result, ECT Canada stated that the BCUC should require B.C. Hydro to model its Code of Conduct on the FERC Standards and to identify those provisions of the FERC Standards of Conduct, if any, that B.C. Hydro has not incorporated into its Code of Conduct and explain why such provisions should not apply to B.C. Hydro (T: 1547). In particular, ECT Canada suggested that there be stronger penalties for non compliance. For example, ECT Canada suggested that the BCUC prohibit a non-regulated affiliate from using any services of the utility for a specified period if there is a transgression of the code (T: 1548).

In response, B.C. Hydro stated that there is no material difference between its code and the FERC Standards of Conduct. Further, B.C. Hydro argued that Tariff Supplement No. 30 section 4 commits B.C. Hydro to meet the industry standards of OASIS requirements and the standards of conduct that are specified by FERC 889, Part 37.4, on which ECT Canada had based its analysis of B.C. Hydro's Code of Conduct. B.C. Hydro stated that it will continue to comply with Part 37 and any other industry standard that develop regarding open access postings and standards of conduct (T: 1000, T: 1790).

With respect to the penalties proposed by ECT Canada, B.C. Hydro indicated that there is no evidence that this type of penalty is imposed in any other jurisdiction and labeled the proposed penalty 'draconian'.

4.2 Commission Determinations

The Commission has carefully assessed the argument put forward by some intervenors that the direction contained in the previous Decision is insufficient and does not adequately protect customers against the potential for B.C. Hydro T&D to favour its affiliates by providing them with preferential access to information and by engaging in discriminatory behavior. In particular, the Commission has assessed the current safeguards implicit and explicit in both the B.C. Hydro T&D Code of Conduct and the requirement in Tariff Supplement No. 30 that B.C. Hydro follow North American industry standard terms and conditions (including those prescribed for U.S. electric utilities by the FERC) and Commission requirements (including standards of conduct) in implementing, operating or utilizing the OASIS to determine if customers are sufficiently protected.

The Commission believes that the Code of Conduct filed in the previous WTS hearing, along with the requirement contained in Tariff Supplement No. 30, clearly indicates the intention of B.C. Hydro T&D to act with integrity and avoid favouring its affiliates or engaging in discriminatory behavior.

The duty of the Commission is not only to ensure that B.C. Hydro T&D's intentions are appropriate but also to ensure that B.C. Hydro is aware of all situations in which B.C. Hydro must guard against both inappropriate behavior and the appearance of inappropriate behavior. Accordingly, in assessing whether the present safeguards are adequate, the Commission must determine whether the current Code of Conduct along with the commitment contained in Tariff Supplement No. 30 provides B.C. Hydro T&D with sufficient guidance as to required behavior.

Finally, the Commission is cognizant of an underlying theme of this hearing, namely the potential benefits to be achieved if the terms and conditions of individual utilities are consistent across jurisdictions.

As indicated above, Tariff Supplement No. 30 requires B.C. Hydro T&D to follow North American industry standard terms and conditions (including those prescribed for U.S. electric utilities by the FERC) and Commission requirements (including standards of conduct) in implementing, operating or utilizing the OASIS. The Commission believes that complying with this requirement implies that such implementing, operating and utilizing of OASIS must be done in a manner consistent with the most current Standards and Protocols issued by FERC. **So that the Commission's wishes in this regard are unambiguous, the Commission directs B.C. Hydro to comply with the current Standards and Communication Protocols for Open Access Same Time Information Systems ("OASIS") as may be issued by FERC from time to time except where to do so is patently unreasonable. In the event that B.C. Hydro believes such compliance to be unnecessary or unreasonable, B.C. Hydro is directed to apply to the Commission for relief from such compliance. The application should state specifically which Standards and Communications Protocols should not apply and why they should not apply.**

With respect to the Code of Conduct, the Commission believes that the current Code adequately addresses the need to keep information confidential regarding energy and transmission schedules and other operating data that is of commercial value to third parties. However, the Commission also recognizes the concerns of third parties with regard to items such as the transfer of personnel between the transmission system operations and affiliates involved in the wholesale merchant functions and with regard to implementation and enforcement of the Code.

The Commission directs B.C. Hydro to file with the Commission a Code of Conduct for Grid Operations and Inter-Utility Affairs, updated as required to address the concerns identified by the Intervenors. Accompanying the Code should be a report which identifies exactly how the proposed Code of Conduct addresses each of the concerns identified by the Intervenors. Where B.C. Hydro has not included specific provisions in the Code which address the concerns,

B.C. Hydro is to explain why it has not done so. The Code is to be filed with the Commission no later than October 31, 1998.

4.3 The Alberta Auction Procedure

In the June 1996 Decision, the Commission directed that there be a simultaneous hourly auction for capacity on the B.C. Hydro – Alberta intertie when the B.C. Hydro – Alberta intertie was constrained. In response to this direction, B.C. Hydro met with the Alberta Transmission Administrator to develop principles and procedures under which the auction would function. As a result of these meetings, an agreement for managing capacity on the intertie was reached by the parties. The terms of the agreement were filed as Attachment J to Tariff Supplement 30.

As set out in Attachment J, up to 50 percent of the Total Transmission Capacity on the intertie will be available for first come first served pre-schedule sales in 24 hour blocks that are exempt from the auction process. Fifty percent or more of the Total Transmission Capacity will be allocated to a pre-schedule day auction of hourly service capacity. In the event that capacity is not constrained, normal tariffs will apply to the auctioned capacity.

Although B.C. Hydro has asked for approval of the Alberta Auction as set out in Attachment J, the Utility also expressed concern that the auction proposal might prove unacceptable to FERC and endanger Powerex's PMA. Accordingly, the Utility asked that the Commission approve Attachment J but, at the same time, find that if B.C. Hydro can demonstrate that the implementation of the auction has or is likely to lead to a denial of access to it or its affiliates to transmission in the U.S. or the loss of a PMA issued to it or its affiliates by the FERC, then the allocation of capacity on the B.C. Hydro-Alberta intertie will revert back to the current method.

ECT Canada was generally supportive of the process proposed by B.C. Hydro for the auction of intertie transmission capacity on the B.C. Hydro-Alberta Intertie but expressed concern about the potential for one party to monopolize all, or virtually all, of the 50 percent of the Total Transfer Capability that B.C. Hydro proposes to make available on a first come first served basis. ECT Canada suggested that this provisions meant that one party could tie up 50 percent of the intertie capacity for long periods of time, leaving other parties access to the intertie only through the auction of hourly service.

Accordingly, ECT Canada suggested that Attachment J to Tariff Supplement No. 30 should include a provision that limits the ability of one party to reserve more than 50 percent of the Total Transfer Capability available under the first come first served process. ECT Canada recognized that B.C. Hydro does not have complete control over Attachment J but suggested that if Gridco would not agree to the changes, B.C. Hydro should be required to explain why.

ECT Canada also suggested that Attachment J should be revised to include a provision that reduces the minimum length of time that capacity must be reserved under the first come first served process from 24-hour blocks to specified peak and non-peak periods during the 24-hour block. Again, ECT Canada stated, that if Gridco does not agree to the changes, B.C. Hydro should be required to explain why.

ZE Power Group Inc. suggested that if the Alberta Auction pricing is accepted by the Commission, the point-to-point rates to and from Alberta should be further reduced by the expected average charge collected through the auction system to avoid pancaking and the resulting over collection from this rate class (T: 1680).

B.C. Hydro stated that the main criticism of the Alberta Auction seems to relate to the 50 percent of the transmission capacity which is to be allocated on a first come first served basis. The Utility indicated that this resulted from the previous Commission Decision and indicated that the decision should not be revisited. In addition, B.C. Hydro indicated that the changes proposed by ECT Canada should have been made explicit during the course of the hearing where they could have been formally debated. Because they had not been brought forward, B.C. Hydro maintained that there is insufficient evidence on which the Commission to find that the changes were desirable.

4.4 Commission Determinations

Based on the evidence and argument presented during the course of this hearing, the Commission approves the auction process proposed by B.C. Hydro with the following change. The Commission directs that Attachment J to Tariff Supplement No. 30 should include a provision that limits the ability of one party to reserve more than 50 percent of the Total Transfer Capability available under the first come first served process. If Gridco does not agree to this change, B.C. Hydro is directed to inform the Commission and give reasons.

As indicated in section 3.3.2, the Commission does not accept the Reversionary Proposal put forward by B.C. Hydro. In the Commission's judgment, approval of the auction process is unlikely to result in the loss of the PMA. Nonetheless, should B.C. Hydro demonstrate that the auction process proves to be detrimental to the PMA, on application, the Commission will move expeditiously to ensure that the PMA is not jeopardized.

Dated at the City of Vancouver, in the Province of British Columbia, this 23rd day of April, 1998.

Original signed by:
Lorna R. Barr
Deputy Chair

Original signed by:
Kenneth L. Hall, P. Eng
Commissioner

Original signed by:
Paul G. Bradley
Commissioner

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ORDER
NUMBER G-43-98

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by British Columbia Hydro and Power Authority
for Approval of its Wholesale Transmission Services

BEFORE: L.R. Barr, Deputy Chair)
K.L. Hall, Commissioner) April 23, 1998
P.G. Bradley, Commissioner)

O R D E R

WHEREAS:

A. In its Decision dated June 25, 1996, the Commission approved the British Columbia Hydro and Powder Authority ("B.C. Hydro") Wholesale Transmission Services ("WTS") Application subject to several changes; and

B. On February 17, 1997, B.C. Hydro filed with the Commission for approval a second WTS Application in response to those determinations and requested interim approval of certain portions of its Application; and

C. On March 24, 1997 the Commission, by Order No. G-31-97, granted interim approval to the Application with the exception of those elements relating to the auction proposal, and directed B.C. Hydro to refile its Electric Tariff Rate Schedules; and

D. Commission Order No. G-53-97 established that the disposition of the B.C. Hydro WTS Application would be through negotiated settlement and Alternate Dispute Resolution procedures; and

E. On June 20, 1997, B.C. Hydro submitted amendments to its WTS Application and requested that the revised Tariff Supplement No. 30, as well as Rate Schedules 3000 to 3010, be approved on an interim basis, effective August 1, 1997; and

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F. On July 2, 1997 the Commission, by Order No. G-77-97, granted interim approval to the revised WTS Application effective August 1, 1997, and directed that the disposition of the Application would now be by way of a public hearing; and

G. On July 16, 1997 the Commission, by Order No. G-83-97, issued a Notice of Public Hearing and a Regulatory Agenda for the B.C. Hydro WTS Application; and

H. On October 10, 1997, the Commission requested comments from Intervenors on the Industrial Customers' request for an adjournment of the November 17, 1997 B.C. Hydro WTS public hearing; and

I. The Commission received comments from eight Intervenors, seven of which supported the Industrial Customers' request for an adjournment of the public hearing. The Commission, under Order No. G-105-97, rescheduled the B.C. Hydro WTS public hearing to commence January 19, 1998 in Vancouver, B.C. A revised Regulatory Timetable was issued as Appendix A to the Order; and

J. The public hearing into the Application took place in Vancouver, commencing January 19, 1998 and concluded nine hearing days later, followed by written argument filed on February 16 and 23, 1998 and Reply Argument by B.C. Hydro by March 2, 1998; and

K. The Commission has considered the Application, written evidence, evidence presented at the hearing and final written arguments filed after the hearing.

NOW THEREFORE the Commission orders B.C. Hydro to comply with the Commission's Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 23rd day of April, 1998.

BY ORDER

Original signed by:

Lorna R. Barr
Deputy Chair

APPEARANCES

G.A. FULTON	British Columbia Utilities Commission, Counsel
C.W. SANDERSON Ms. A. DOBSON-MACK D.L. RICE	British Columbia Hydro and Power Authority
R.B. WALLACE	Council of Forest Industries; The Mining Association of British Columbia; and Electro-Chemical Producers
R.H. HOBBS	West Kootenay Power Ltd.
V.J. LANDRY	Enron Capital and Trade Resources Canada Corporation
J.D.V. NEWLANDS	Fording Coal
P. BERGER	Bonneville Power Administration
J. YARDLEY K. EPP	Columbia Basin Trust Power Corporation
M. DOHERTY	Consumers' Association of Canada (B.C. Branch) et al. [British Columbia Old Age Pensioners' Organization, Council of Senior Citizens' Organizations of B.C., Federated Anti-Poverty Groups of B.C., Senior Citizens' Association of B.C., West End Seniors' Network, B.C. Coalition for Information Access, End Legislated Poverty and the Tenants' Rights Coalition]
Ms. C. REARDON	Association for the Advancement of Sustainable Energy Policy
Z. EL-RAMLY	ZE Power Group Inc.
Ms. M. LAURIE	International Brotherhood of Electrical Workers, Local 258
H. LEDERHOFF	Ecology Circle
R. McLAUGHLIN	Ministry of Employment and Investment

APPEARANCES
(cont'd.)

A. RAWLINGS	UtiliCorp Energy Services Ltd.
D. HUTCHINSON	Inland Pacific Energy Services Ltd.
R. ZEILSTRA	Columbia Power Corporation
Ms. P. COCHRANE P. WILLIS	Willis Energy Services Limited

D.W. EMES C. B. LUSZTIG	Commission Staff
ALLWEST COURT REPORTERS LTD.	Court Reporters & Hearing Officer

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