IN THE MATTER OF

British Columbia Hydro and Power Authority

1994/95 Revenue Requirements Application

DECISION

November 24, 1994

BEFORE:

Dr. M.K. Jaccard, Chairperson
F.C. Leighton, P.Eng., Commissioner
K.L. Hall, P.Eng., Commissioner

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EXECUTIVE SUMMARY

On February 11, 1994, B.C. Hydro applied to the B.C. Utilities Commission for orders approving a 2.8 percent permanent increase in electric service rates effective April 1, 1994. B.C. Hydro prepared its application based upon the December 1993 load forecast and then current financial information. On August 31, 1994, the utility filed an update to its load forecast and financial information but did not amend its application.

The application was heard over 13 days of public hearings in Vancouver commencing September 12, 1994. After reviewing all the evidence and additional information made available from both the applicant and registered intervenors, the Commission makes the following determinations.

Revenue Requirements

The provincial government's Special Direction No. 8 to the Commission requires that B.C. Hydro be allowed to generate sufficient revenues to achieve an annual rate of return on equity equal to that allowed on a pre-income tax basis by the most comparable investor-owned energy utility regulated under the Utilities Commission Act. The Commission agrees with B.C. Hydro that BC Gas is the most comparable utility for purposes of that direction. The Commission has incorporated the most recent BC Gas effective tax rate of 16.39 percent and return on equity of 10.65 percent in its calculations, determining that the required pre-income tax rate of return to be earned by B.C. Hydro is 12.74 percent.

The Commission accepts the forecast of electricity sales revenue from B.C. Hydro's original Application. That forecast assumes normal weather conditions during the fiscal year.

In reviewing B.C. Hydro's budgets and its budget approval process, the Commission focused on the issues of cost control and changes made to the budget approval process since the previous hearing. In the last decision, dated December 7, 1993, the Commission expressed concern regarding the projected increases in operations, maintenance and administration expenditures ("OMA"). The Commission notes that actual OMA expenditures for the 1993/94 fiscal year were significantly reduced from those originally forecast, and that this reduction has not affected the quality of service. The OMA expenditures forecast for the 1994/95 fiscal year were approximately equal to the actual expenditures in 1993/94. However, in reviewing the evidence and testimony from the hearing, the Commission is not satisfied that B.C. Hydro has demonstrated that OMA expenditures are being constrained to a level consistent with the most efficient operations and lowest cost to customers, while maintaining the existing levels of reliability. The Commission is of the view that some further restraint in overall OMA expenditures is appropriate and this Decision incorporates a small reduction.

Insofar as carrying charges on capital investments make up nearly one-half of the revenue needs of the Utility, the Commission examined the capital spending plans. Between June, 1993 and September, 1994, B.C. Hydro staff prepared at least three capital budgets for fiscal 1994/95 ranging from $741 million to $607 million. Review by management reduced the final forecast budget to $575 million. The Commission instructs B.C. Hydro to make every effort to constrain Capital expenditures for fiscal 1995/96 and 1996/97 to $575 million plus a modest escalation related to the increase in the number of customers. In addition, the Commission expects B.C. Hydro to complete a full review of its information technology needs before making any major financial commitments and to keep the Commission fully informed of its plans.

B.C. Hydro's updated finance charges, filed in August 1994, showed a significant increase due to higher interest rates and a weakening of the Canadian dollar. The Commission concludes that the more recent information supports an increase in finance charges of $10 million over the original application to a total of $700 million, and the Commission has made this adjustment in its determination of the revenue requirement.

B.C. Hydro prepared the financial forecasts using an amount of $35 million for electricity trade income based upon its interpretation of Special Direction No. 8. The Commission does not agree with that interpretation and is of the view that, if the provincial government had intended the use of the $35 million amount at all times, it would have used different wording in the Special Direction. The Commission concludes that the only valid numbers from which it can establish the volume of net export revenue, in an average water year consistent with the methodology suggested in Special Direction No. 8, are those provided by B.C. Hydro for the 1994/95 fiscal year and that $59.35 million is the amount of electricity trade income to be used in the revenue requirement calculation.

The cumulative effect of these and other Commission determinations are detailed in Table 7.1 in this decision. The Commission denies the rate increase and orders B.C. Hydro to refund the interim increase collected since April 1, 1994. Rate design changes directed from this and previous decisions, will be implemented to move residential and general service customers toward flat rates.

Integrated Resource Planning

Integrated Resource Planning ("IRP") is a process which requires consideration of all known resources for meeting the demand for a utility's product, including those which focus on energy conservation and load shifting. IRP bears a direct relationship to customer rates, in that the Action Plan flowing from the IRP provides the justification for capital expenditures in generation and, increasingly, transmission and distribution.

In early 1993, the Commission issued its IRP guidelines and directed utilities under its regulation to submit draft IRPs by December 31, 1993, unless otherwise instructed. By letter dated March 22, 1993, B.C. Hydro informed the Commission that it believed its 1992 Electricity Plan met the general requirements of an IRP. Accordingly, the Commission reviewed the 1992 Electricity Plan and related documents for consistency with the elements of an IRP, as set out in the BCUC guidelines. In its December 7, 1993 decision on B.C. Hydro's rate application, the Commission agreed with B.C. Hydro that its 1992 Electricity Plan was reasonably consistent with general IRP principles. However, a number of areas were noted in which the 1992 Electricity Plan needed to be substantially improved to better meet the requirements of IRP and the Commission issued specific directions to B.C. Hydro in this regard.

After an extensive review in this hearing, the Commission finds that B.C. Hydro has failed to follow the Commission's IRP guidelines and, in several areas, particularly with respect to public involvement, has failed to comply with certain specific directions given to it by the Commission as part of the 1993 decision. As a result, the Commission determines, as a finding of fact under Section 65(3) of the Utilities Commission Act, that it would be unjust and unreasonable to allow the full amount of the Resource Planning Unit budget to be recovered in rates at this time. In addition, the lack of compliance with the Commission's directions with respect to IRP has forced the Commission to make determinations throughout this decision which are of a more detailed and intrusive nature than has been its normal custom. Notably, B.C. Hydro is directed to constitute forthwith an IRP consultative committee charged with responsibility to provide public input into a new version of the utility's IRP by June 30, 1995. Other detailed Commission directions to the utility with respect to IRP are to be found in the body of this decision.

1.0 INTRODUCTION

The British Columbia Utilities Commission ("the Commission", "BCUC") is a regulatory agency of the provincial Legislature operating under, and administering, the Utilities Commission Act. The Commission's primary responsibility is the regulation of the energy utilities under its jurisdiction to ensure that the rates charged for energy are fair and reasonable, and that utility operations are safe and provide adequate and secure service to their customers. It approves construction of new facilities planned by utilities and their issuance of securities. Within the areas of its jurisdiction, the Commission has been given exclusive powers, which it exercises in a quasi-judicial manner.

Under the Utilities Commission Act, the onus is on public utilities to present sufficient evidence to justify their rates. To this end, applications are filed which contain a great deal of technical information. This material is generally examined in hearings open to the public, and the Commission arranges publication of a Notice of Hearing, setting out a schedule for the filing of Interventions, Information Requests and additional Evidence. Intervenors and other interested parties have an opportunity at the hearing to present their own views, to cross-examine the Applicant's witnesses and to argue on the merits of the evidence.

The British Columbia Hydro and Power Authority ("B.C. Hydro", "the Applicant", "the Company", "the Utility") is a provincial Crown Corporation, with a mandate to generate, transmit and distribute electricity in British Columbia. B.C. Hydro does so throughout British Columbia, except for a few municipal district 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 Commission. All the provisions of the Utilities Commission Act ("the Act") apply to the Utility except for the sections dealing with utility financing and asset dispositions.

1.1 Background

B.C. Hydro last applied for a general rate increase in February 1993 to be applicable for the fiscal period commencing April 1, 1993. The application was based upon Special Direction No. 8, issued by the provincial government to the Commission, pursuant to Section 3.1 of the Utilities Commission Act, on November 13, 1992. Accordingly, that application took into account the provisions contained in the Special Direction concerning rate increases and rate design. A public hearing into the application was held in September 1993 and, in its Decision of December 7, 1993, the Commission approved the requested 3.9 percent increase effective April 1, 1993.

At that hearing, B.C. Hydro also asked for a variance to the 1992 Rate Design Decision. With respect to residential rates, the Utility requested that the Commission allow the creation of a middle block and application of revenue increases, such that flat rates would be achieved over a longer period of time, estimated to be around the turn of the century. B.C. Hydro also requested that the Commission approve changes to the restructuring of the general service customer rates determined by the 1992 Rate Design Decision.

The Commission denied the rate design changes and directed B.C. Hydro to achieve flat rates for residential customers in two approximately equal steps, commencing with consumption from January 1, 1994. The second step was to be achieved with the next rate application. The Commission also directed the Company to achieve flat rates for general service customers by the time of the 1995/96 fiscal year with the first step also to commence effective with consumption starting January 1, 1994.

The Commission had issued its Integrated Resource Plan ("IRP") guidelines in February 1993 to aid utilities in developing their plans and B.C. Hydro subsequently submitted its 1992 Electricity Plan as meeting the general requirements of an IRP. The December 7, 1993 Decision directed B.C. Hydro to make those changes which were necessary either to convert the Electricity Plan into a full Integrated Resource Plan or produce both an Electricity Plan and an IRP.

1.2 Application

On February 11, 1994 B.C. Hydro applied to the Commission for Orders approving a 2.8 percent permanent increase in electric service rates effective April 1, 1994, for the fiscal year ending March 31, 1995, based upon rate design proposals set out in the Application. Under Commission Order No. G-18-94 dated March 4, 1994, an interim increase in the amount of 2.8 percent effective April 1, 1994 was approved and a public hearing was scheduled to commence in Vancouver on Monday, September 12, 1994. Subsequently, Commission Order No. G-30-94 set out the dates for registering of Intervenors and Interested Parties and for the filing of Information Requests, written evidence and additional materials from both the Applicant and Intervenors and budgets for those Intervenors intending to apply for Participant Funding. The Application was heard over 13 days, with final argument in written form.

The Application is based upon Special Direction No. 8 and takes into account the provisions contained in that Special Direction concerning rate increases and rate design. The Application indicated that, in order to comply with Special Direction No. 8, paragraph 4(d), the Company would be required to earn a return on equity of 14.18 percent (Exhibit 1, p. I-4-19). This was subsequently modified to 13.5 percent, in order to account for the Commission's June 10, 1994 Decision concerning the rate of return on common equity for BC Gas Utility Ltd. ("BC Gas"), which B.C. Hydro chose in this Application as the most comparable utility for purposes of Special Direction No. 8. Increased expenditures on the cost of energy, taxes and finance charges were also cited as being the rate drivers necessitating an increase.

Although the Company requested an overall 2.8 percent rise in rates, individual residential customers would see annual bill changes ranging from reductions of 6.5 percent to increases of 8.1 percent if the Application were approved as filed, due to the impact of the flattening of residential rates.

B.C. Hydro specifically requested that the following Orders be issued:

1. An Order pursuant to section 67 of the Act allowing B.C. Hydro to amend its Electric Tariff filed with the British Columbia Utilities Commission to implement any rate increases it is granted pursuant to this Application in a manner consistent with that set out in this Application;

2. An Order pursuant to section 64 of the Act confirming an increase in electric service rates of 2.8 percent to be applied to the classes of service in a manner consistent with that set out in this Application.

2.0 REGULATORY FRAMEWORK AND POLICY

The Commission is instructed and guided by the provisions of the Utilities Commission Act, inclusive of Special Directions issued pursuant to sections 3 and 3.1 of the Act. The latter specifically concerns the "authority", i.e. B.C. Hydro:

> "3.1 The Lieutenant Governor in Council may issue a direction to the commission specifying the factors, criteria and guidelines that the commission shall or shall not use in regulating and fixing rates for the authority and the commission shall comply with the direction notwithstanding:
>
> (a) any other provisions of this Act, or
> (b) any previous decision of the commission."

It is not uncommon for legislation that governs regulatory commissions to contain provisions whereby governments may give direction to their respective agencies, although in many cases such direction is limited to general direction on broad policy matters. In British Columbia, however, it should be noted that the government has chosen to enable both general and specific direction to be given, particularly in regard to B.C. Hydro.

2.1 Special Direction No. 8 to the BCUC

By Order in Council No. 1684, dated November 13, 1992, the Commission was issued Special Direction No. 8 which is as follows:

"**Application:**

1. This Special Direction is issued by the Lieutenant Governor in Council to the British Columbia Utilities Commission (the "Commission") under authority of section 3.1 of the Utilities Commission Act (the "Act") with respect to the exercise of the Commission's powers and functions as they apply to the British Columbia Hydro and Power Authority ("B.C. Hydro").

Definitions:

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

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

(b) "deferred credits" means the sum of the Rate Stabilization Account, deferred revenue, contributions arising from the Columbia River Treaty and contributions in aid of construction;

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

(d) "total invested capital" means debt plus equity, at the end of the financial year.

Conservation and Efficient Electricity Use:

3. In designing B.C. Hydro electricity rates, the Commission shall ensure that those rates contribute to conservation and efficient electricity use by reflecting the total cost of new sources of electricity supply, and those costs shall be evaluated using a cost of capital consistent with that earned on a pre-income tax basis by the most comparable investor-owned energy utility regulated under the Act.

Basis for Establishing Revenue Requirements:

4. In order to determine an appropriate basis for establishing B.C. Hydro revenue requirements and a fair and reasonable return for B.C. Hydro comparable to, and competitive with, returns earned on total invested capital by investor-owned utilities, the Commission must allow B.C. Hydro to generate sufficient revenues in each financial year to:

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

(b) meet other expenses reasonably incurred in accordance with government policy directives;

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

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

5. The return on equity in paragraph 4(d) must be calculated using consolidated operating income from all sources before any Rate Stabilization Account transfers, where projections of consolidated operating income include an amount of electricity trade income consistent with the Commission's forecast of annual net export revenue under average water conditions, as contained in the Commission's report to the Lieutenant Governor in Council dated June 30, 1992, as amended, on B.C. Hydro's Energy Removal Certificate application.

Smooth, Stable and Predictable Rate Increases:

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

6.2 Smooth, stable and predictable rates for the purpose of setting B.C. Hydro electricity rates means that, with the exception of pass through items pursuant to section 67(4) of the Act, general electricity rate increases shall not exceed 1 percentage point above the rate of inflation for the remainder of the 1992/93 financial year and shall not exceed 2 percentage points above the projected rate of inflation on a year over year basis thereafter.

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

6.4 The rate of inflation in paragraph 6.2 means the change in the average level of the British Columbia consumer price index during the most recent three month period for which published statistics are available prior to B.C. Hydro's rate application filing, compared to the average level of the British Columbia consumer price index during the same three month period a year earlier, and published statistics shall mean those published by Statistics Canada.

6.5 The projected rate of inflation in paragraph 6.2 means the provincial Ministry of Finance and Corporate Relations, latest available forecast published prior to B.C. Hydro's rate application filing of future year over year changes in the average level of the British Columbia consumer price index.

Fair, Just and Reasonable Rates:

7.1 In setting B.C. Hydro electricity rates the Commission shall ensure that rates are fair, just and reasonable.

7.2 Notwithstanding Part 3 of the Act or any previous decision of the Commission, fair, just and reasonable rates for the purpose of setting B.C. Hydro electricity rates means rates set in accordance with this Special Direction.

Return on Public Investment:

8. Electricity rates set by the Commission in accordance with this Special Direction may generate annual distributable surpluses for B.C. Hydro. These surpluses shall only be calculated and allocated in a manner specified by the Lieutenant Governor in Council pursuant to section 54.1(a) of the Hydro and Power Authority Act.

This Special Direction revokes and replaces Special Direction No. 3 of October 5, 1989."

B.C. Hydro stated that the current Application was based upon Special Direction No. 8 and that it meets the requirements of that document. B.C. Hydro further stated that its Application also met the requirements of Special Directive No. 2, issued by the provincial government to B.C. Hydro on November 13, 1992, pursuant to Section 54.1 of the Hydro and Power Authority Act.

2.2 Most Comparable Utility

In the Commission's previous B.C. Hydro Decision of December 7, 1993, the first under Special Direction No. 8, the Commission stated that it wished to hear further evidence with respect to appropriate tax calculations and the most comparable investor-owned energy utility in the next revenue requirement application. In accordance with that Decision, B.C. Hydro restricted its evaluation of comparative utilities to BC Gas and WKP.

After comparing the size and location of operations, nature of business and capital structure (Exhibit 1, Tab 4), the Utility determined that BC Gas was the most comparable utility for all of the criteria except nature of business, for which it determined that WKP was the most comparable. B.C. Hydro then filed the current Application on the basis that BC Gas is the most comparable investor-owned utility.

The Commission has reviewed the evaluations of BC Gas and WKP made by B.C. Hydro as to which is the most comparable utility for purposes of Special Direction No. 8 and agrees that, on balance, BC Gas is currently the most appropriate utility to be used for purposes of determining the pre-income tax rate of return to be earned by the Company.

2.3 Effective Tax Rate

Special Direction No. 8, Paragraph 4, requires that B.C. Hydro be allowed to earn an annual return on equity ("ROE") equal to that allowed the most comparable investor-owned utility on a pre-income tax basis. In regulating investor-owned utilities, the Commission accepts income taxes either paid or due to be paid as an expense before calculating net income. The approved ROE is then calculated with respect to income on an after-tax basis.

As B.C. Hydro is not required to pay income taxes, it uses an "effective tax rate" in determining pre-income tax ROE of both the most comparable utility, BC Gas, and itself. The Application defines the effective tax rate as:

$$\frac{\text{Income Tax Expense less Large Corporation Tax}}{\text{Accounting Income after Tax plus (Income Tax Expense less Large Corporation Tax)}}$$

(Exhibit 1, p. I-4-16)

The current Application, in keeping with the interpretation that BC Gas is the most comparable utility, initially based the effective tax rate on that available from the 1994 rate application as filed by BC Gas, a rate of 21.64 percent. The Commission, in its Order of December 9, 1993 (No. G-120-93), allowed BC Gas an interim ROE of 11.2 percent but did not determine an effective income tax rate. As this was less than the ROE requested by BC Gas, B.C. Hydro reduced the effective income tax rate for purposes of its application to 21 percent (Exhibit 1, p. I-4-17).

At the time of this hearing, the Commission had issued its Decision and Orders concerning the BC Gas revenue requirements application. However, the Decision did not include schedules detailing the effective tax rates for the gas utility. On October 6 and 14, 1994, BC Gas filed detailed financial schedules and rates that incorporated the results of the Commission Decisions and Orders. These schedules were accepted and approved by the Commission under Order No. G-73-94 and indicate an effective tax rate of 16.39 percent for the year ending December 31, 1994.

The Commission has determined that the amount of 16.39 percent is the effective income tax rate for the purposes of this Application.

2.4 Pre-Income Tax Rate of Return

The pre-income tax rate of return of 14.18 percent used by B.C. Hydro, in the February 1994 Application, was calculated using the 21 percent effective tax rate allowed by the Commission to BC Gas in Order No. G-120-93 on December 9, 1993 (Exhibit 1, p. I-4-19). Without amending its

Application, on August 31, 1994 the Utility filed its latest forecast of results and, for purposes of determining the payment to the province, used a pre-income tax rate of return of 13.5 percent. This revised rate of return was based upon the ROE of 10.65 percent awarded to BC Gas by way of the Commission Decision of August 4, 1994 through Order No. G-59-94 concerning BC Gas' 1994/95 Revenue Requirements application Phase 2.

The Commission has incorporated the effective tax rate of 16.39 percent and an ROE of 10.65 percent in its calculations. As a result, the Commission determines that the required pre-income tax rate of return to be earned by B.C. Hydro under Special Direction No. 8 is 12.74 percent.

3.0 FINANCIAL ANALYSIS

3.1 Budget Review and Approval Process

In the 1993 hearing, Commission counsel and Intervenors extensively reviewed the Utility's Operations, Maintenance and Administrative ("OMA") expense and Capital Expenditure budget approval process. The Utility had a "top down and bottom up" process in which the various work groups plan their budgets without knowing the target framework which management believes is appropriate at the time. Mr. Harrison, and B.C. Hydro's policy witness, Mr. John Sheehan, were concerned that the business unit budgets should be based on need first, prior to the setting of OMA targets by management (1993 Hearing, T. 206).

The February 1994 Application indicated a significant change to the process in that the OMA targets set by management are now communicated to the working groups much earlier in the budget preparation process.

> "Target setting (top down) and work planning (bottom up) come together early in the planning process. Analysis of different financial framework scenarios, operational requirements and expenditure trends result in the establishment of preliminary Corporate and SBU/CSG (Groups) OMA targets. These OMA targets are now communicated to the Groups who are encouraged to prioritize work activities to stay within their OMA targets. Any planning or budgeting issues are discussed and resolved at the senior management level and appropriate adjustments made to the OMA targets.
>
> The various work plans and budgets are then consolidated into Group plans which are presented to and reviewed by the responsible Vice Presidents, the Senior Management Committee of B.C. Hydro and the Audit and Budget Committee of the Board of Directors. Changes to the work plans and budgets can occur at any level of review. The budget is finalized only after receiving approval from the Board of Directors based upon the recommendations of the Audit and Budget Committee." (Exhibit 1, p. I-6-F-6)

In the 1994 hearing, Mr. Harrison, Vice-President of Finance, indicated that the detailed budgets provided by the Key Business Units ("KBU") would have been around $450 million for OMA (T. 696). As was done in last year's budget process, the initial upper limit for fiscal 1994/95 OMA, adjusted for customer growth, inflation and productivity increases, was determined. This was calculated at $440 million, $10 million less than what the KBUs felt they needed. The upper limit for capital was determined to be $655 million. Despite the evidence provided by its KBUs, senior management actually imposed an OMA target of $409 million and a capital target of $575 million. B.C. Hydro management felt that the key issues in arriving at this determination were:

1. compliance with Special Directive No. 2 and Special Direction No. 8.

2. sufficient funding to support B.C. Hydro's ongoing business requirements and make significant strides toward achieving its strategic initiatives.

3. keeping rate increases close to or below the forecast inflation rate

4. maintaining an 80:20 debt/equity ratio (Exhibit 2, BCUC 64-5).

B.C. Hydro management obviously feels that, at this time, the perceived needs of the individual business units must be constrained by other factors. The Commission agrees and, under its mandate to set just and reasonable rates, has used similar principles to determine the appropriate OMA and capital expenditures, as noted in Section 3.4 of this Decision.

In prior years, formal management plans were prepared by all KBU's and consolidated into the management plan of the respective Corporate Service Group or Strategic Business Units ("CSG/SBU"). This requirement has now been eliminated and the business units are only required to prepare a formal plan if specifically directed; otherwise, the KBU continues to go through a budgeting process that involves approval by the unit head and, ultimately, senior management. The significant difference is that there will no longer be any commentary and review of the past year accompanying the new budget. The Utility removed the requirement for a formal KBU management plan in the interest of increased efficiency. However, it was acknowledged by Mr. Harrison that "the jury's still out" as to whether the change was for the better (T. 706).

The Commission's 1993 Decision determined that the Company's management "should apply more rigorous analysis to a greater proportion of the work plans than currently appears to be the case" (p. 32). The elimination of the formal business plan appears to reduce the amount of analysis performed by management. In recent application reviews, the Commission has attempted to utilize the Utility's own budget approval process as a cost-effective means of providing all hearing participants with an adequate level of knowledge of the Company's operations and plans, but if the level of detail and analysis in each management plan is reduced, the Commission may be forced to impose additional information requirements in support of future applications.

The Commission directs that B.C. Hydro review its policy of optional preparation of complete management plans by its KBU's. Further, the Utility must provide to the Commission and Intervenors, budget information, with commentary prepared by the SBU's, CSG's and KBU's, in support of its future rate applications.

Greater quantities of information tend to equate to larger volumes of documentation, making review of the material less efficient. A workable solution to the problem lies in the availability of electronic copies of the budgetary information. B.C. Hydro has stated that the budgets are communicated to employees by electronic means, in addition to hard copy. Provision of the electronic versions of the documentation would allow greater access to a larger number of Intervenors, as discussed in Section 6.1 of this Decision.

Intervenors commented negatively on the insufficient explanations of the capital expenditure budgets within the Application itself, especially in comparison to the information provided by other utilities under Commission jurisdiction. B.C. Hydro provided further documentation in response to Information Requests and obviously has a great deal of information available in its system at a minute level (such as its Capital Authorization Request Tracking Reports). Moreover, B.C. Hydro is planning capital expenditures of about $6 billion over the next ten years, and is currently spending between $500 and $600 million each year (T. 432). Over time, this has a critical impact on customer rates, as discussed in Section 3.6 of this Decision. The challenge will be to provide a useful level of detail for review within the context of rate hearing applications.

The Commission directs B.C. Hydro to present information on capital expenditures in future rate applications in a manner similar to that of BC Gas at Tab 3 of its 1993 Application and WKP at Tab 3 of its 1993 Application.

3.2 Forecast Revenues

B.C. Hydro prepared its Application in February 1994 based upon the December 1993 load forecast. On August 31, 1994 the Utility filed an update to its financial information consisting of a "Forecast Consolidated Statement of Operations" for the fiscal year 1994/95 compared to the "Plan" upon which the Application was filed (Exhibit 1, p. I-7-D2 - D6).

The Application revenues were initially prepared assuming normal weather for the entire test year, fiscal 1994/95. B.C. Hydro prepared its updated information based on actual financial results for the first four months ending July 31, 1994 and assumed normal weather for the period from August 1, 1994. In the information update, general revenues were adjusted to $7 million below Plan due to slower than anticipated growth in commercial accounts (Exhibit 1, p. I-7-D5). Another $18 million downward adjustment was attributed to a warmer than average spring and early summer (T. 88).

The Industrial Customers submitted that the adjustment for warmer than normal weather was not appropriate and that accepted utility practice for forecasting revenues always assumes normal weather. B.C. Hydro responded in the Reply Argument that, "if the August 1994 forecast were a revised Application, it would be appropriate to normalize revenues for weather - however, as stated above this forecast was not a revised Application." (T. 2828).

The Commission acknowledges B.C. Hydro's argument that it has not filed an amended Application. However, the Commission's responsibility includes both testing the original application for acceptability of revenues and costs and assessing whether or not compelling post-application changes in circumstances warrant adjustments. Uncertainty is integral to utility demand forecasts, for which utilities are compensated by receiving a return on equity in excess of government bonds.

The Commission accepts the revenue forecast from B.C. Hydro's original Application for purposes of determining the appropriate customer revenues. The Commission establishes revenue requirements for utilities under its jurisdiction based on forecasts of normal weather conditions, recognizing that actual earnings will reflect the variability of sales related to forecasting error, be that caused by weather or other factors.

3.3 Electricity Trade Income

3.3.1 <u>BCUC Report on the 1993 Energy Removal Certificate Application</u>

The Report and Recommendation of the Commission on B.C. Hydro/Powerex's Energy Removal Certificate Application ("ERC") was issued to the Lieutenant Governor in Council on June 30, 1992. Subsequently, ERC-E01(9207) was issued to B.C. Hydro, effective October 1, 1992.

The Commission's 1992 report concluded that the net benefits of electricity trade, based on B.C. Hydro's export projections for the five year period 1992 - 1997 were "positive and significant". In the report, the Commission pointed out the difficulty in allocating exports from an integrated system to specific generating sources. Nevertheless, based largely on the evidence of B.C. Hydro's 1992 - 1997 export projections, it concluded that it would be reasonable to assume that export sales would be derived from a mix of resources, i.e. purchased electricity, self-generation at the Burrard thermal plant and generation from hydro-electric sources. Under *average* stream flow conditions the evidence suggested that this mix would likely comprise 41.7 percent purchases, 33.3 percent Burrard and 25 percent hydro-electric, and that exports would probably comprise 3,000 GW.h of interruptible and 1,000 GW.h of firm energy. Under those conditions, and under the 1992 - 1997 export projections, the Commission concluded that the total B.C. Hydro annual net benefit from electricity trade, in a year of average stream flow conditions, would be about $35 million (Table 7.6 p. 126, 127 ERC Report).

In the ERC Report, the parameters of the analysis and the basis for the selection of 4,000 GW.h of energy trade were outlined. The Report stated that:

> "This projection is based on B.C. Hydro's simulations, which assume probable demand and average water over a range of stream flow conditions. Export volumes derived from the simulations are attributed to specific resources (purchases, Burrard, Hydro) by application of B.C. Hydro's 'Marginal Cost Model' on a one year hindsight basis. Under this procedure incremental costs of operation are assessed against export volumes in order of descending short run incremental cost - that is, first purchases, then Burrard output, and finally the residue to hydro. These costs are deducted from export revenue at the Canadian border to determine the contribution margin and net revenue." (p. 104)

Transmission costs were excluded from the calculation of electricity trade income, as the Report stated that:

> ". . . Canadian export prices are net at the Canadian border; incremental environmental costs are excluded; provision made for incremental operating and maintenance expense and transmission losses where appropriate; excludes incremental costs of wheeling within B.C." (Footnote 2, p. 105).

The reference to the exclusion of incremental environmental costs is also important. In its 1992 ERC report, the Commission recommended that B.C. Hydro "should be required to move toward incorporation of an appropriate allowance in its selling price for social/environmental costs associated with the generating sources". The report goes on to say "B.C. Hydro stated on numerous occasions that it normally sought a 0.5 ¢/kW.h (5 mills) margin over cost in pricing its energy exports. The Commission accepts this as a conservative allowance to ensure that . . . all such undetermined costs and risks will be covered" (ERC Report, p. 46).

3.3.2 Special Direction No. 8 to the Commission

Following the ERC report, Special Direction No. 8 was issued to the Commission. It contained the following direction concerning the allowable rate of return on equity to the Crown-owned utility, B.C. Hydro:

> "The return on equity in paragraph 4(d) must be calculated using consolidated operating income from all sources before any Rate Stabilization Account transfers, where projections of consolidated operating income include an amount of electricity trade income consistent with the Commission's forecast of annual net export revenue under average water conditions, as contained in the Commission's report to the Lieutenant Governor in Council dated June 30, 1992, as amended, on B.C. Hydro's Energy Removal Certificate application."

3.3.3 B.C. Hydro's Interpretation of Special Direction No. 8

On June 30, 1994, in response to the current rate increase application, Commission staff issued an Information Request to B.C. Hydro, requesting up-to-date five year projections of electricity export trade, with the expressed intention "to update the information provided in the 'Report and Recommendations to the Lieutenant Governor in Council' concerning the 'Energy Removal Certificate' (dated June 30, 1992)". (Exhibit 2, BCUC 69 and 70).

In its response, B.C. Hydro stated that, in its view, Special Direction No. 8 required that $35 million be used for the value of export trade, notwithstanding the fact that it was forecasting net electricity trade income of $59 million in the 1994/95 Plan which formed the basis of its rate Application (Exhibit 1, p. I-7-B7.1). The rationale for using $35 million was its interpretation of paragraph 5 of the Special Direction. B.C. Hydro concluded its response to BCUC 69 with the statement:

> "B.C. Hydro has used this figure in all it's calculations. As B.C. Hydro's application is only for the fiscal year 1995 and as this year is covered in your report, B.C. Hydro does not see the relevance of any further examination in this respect." (Exhibit 2, BCUC 69).

This stance was reiterated by counsel for B.C. Hydro at the rate application hearing. B.C. Hydro did not provide the requested five year projection of export trade to the Commission.

Subsequently, during cross-examination of B.C. Hydro's witness panel, both the Industrial Customers and Commission counsel pressed B.C. Hydro to provide at least partial answers to BCUC 69, the request for a five year projection of electricity trade and revenue. As a result, Exhibits 16 and 26 were filed during the hearing, providing part of the requested information, but only for the three years 1995 - 1997. For convenience, the information from Exhibits 16 and 26 is consolidated in Table 3.3.1.

Commission Determinations

The Commission is of the view that Special Direction No. 8 intended projections of B.C. Hydro's consolidated operating income to include an amount for electricity trade, based on forecasts of that trade under average stream flow conditions, to be derived in a manner "consistent with" that used in its 1992 ERC report. Further, the Commission is of the view that if the government had intended the Commission to use the fixed annual electricity trade figure of $35 million it would have either stated this number or used the words "equal to" in the Direction. Instead the Commission is directed to use an amount "consistent with" the Commission's forecast contained in the 1992 report.

As a result of B.C. Hydro's failure to provide the five year forecast requested in BCUC 69, the Commission has reviewed the three year forecast from Exhibits 16 and 26. However, closer examination of the three year figures revealed the data for 1995/96 and 1996/97 to be highly questionable. This may be partially explained by the annotation on page 2 of Exhibit 26 that "forecast information for the next five years, similar to the information used in the ERC, is not readily available". Unfortunately, this lack of availability is in spite of the fact that Commission staff placed B.C. Hydro on notice, in June 1994, of its desire for the five year forecast.

Table 3.3.1

Fiscal Years	1995	1996	1997
Forecast of Electrical Sales (GW.h)			
Firm	**2072**	1161	1500
Interruptible	**2161**	3010	2427
Total	**4233**	4171	3927
Cost of Energy Required to Meet the Sales Forecast			
Weighted Average Cost (mills)	**20**	26	27
Cost of Electricity Trade (in millions)	**84**	108	106
Average Export Prices for Firm and Interruptible			
Firm (mills)	**39.6**	37.9	36.0
Interruptible (mills)	**34.7**	30.6	31.3
Sales Revenue ($ millions)			
Firm	**82**	44	54
Interruptible	**75**	92	76
Total Sales Revenue	**157**	136	130
Cost of Sales ($ millions)			
Energy	**84**	108	106
Transmission	**5**	5	5
Powerex	**8**	5	5
Net Trade Income ($ Millions)			
Net	**60**	18	14

Source: B.C. Hydro
Exhibits 16 and 26

The following are some of the inconsistencies in the 1995/96 and 1996/97 data.

1. The volume of electricity trade in each year is within 4.3 percent of the 4,000 GW.h which, in the Commission's 1992 Report, was determined to be the norm for an average water year. It is therefore unlikely that inconsistencies elsewhere can be explained by abnormal water conditions.

2. The energy cost of electricity trade is forecast to rise by 30 percent in 1995/96 and by a further 4 percent in 1996/97. No explanation is provided. If the increase relates to gas costs, which impact Burrard, the effect should have appeared in the 1994/95 fiscal year. There is evidence that gas costs are in fact currently moderating and one would expect 1995/96 and 1996/97 fuel costs to be no higher than in 1994/95.

3. If, indeed, the sharply higher forecast energy costs in 1995/96 and 1996/97 are due to predicted increased fuel charges, one would expect such fuel price escalation to put upward pressure on electricity prices, in a North American context. Instead, B.C. Hydro is predicting electricity export unit revenues to *decline* in 1995/96 and 1996/97 by approximately 5 percent each year in the case of firm energy. At the same time, interruptible unit revenues are projected to decline by 11.8 percent in 1995/96 with a small recovery in 1996/97. It is interesting to note that B.C. Hydro's 1992 five year projection showed unit export revenues reaching a peak in 1995/96 and 1996/97.

4. If the electricity trade weighted average margin figures for 1995/96 and 1996/97 are valid, they indicate that, in these years, interruptible sales margins will be as low as 4.6 mills/kW.h and 4.3 mills/kW.h respectively. This is below the 5 mill margin which B.C. Hydro assured the Commission in 1992 it always sought to maintain, to cover non-included social/environmental external costs.

As a result of its review of the 1995/96 and 1996/97 forecast data, the Commission has concluded that the only available numbers from which it can establish, in a manner consistent with its 1992 ERC evaluation, the volume of net export revenue in an average water year, is that provided by B.C. Hydro for the 1994/95 fiscal year.

For the 1994/95 fiscal year, the cost of energy sales was provided as a weighted average unit cost of 20 mills. Exhibit 26 did not break this unit cost down, but from the Energy Removal Certificate Application Decision (p. 127, Table 7.6) and based on the range of incremental costs, Burrard was set at 14 mills and hydro-electric at 5.5 mills. The established allocation weightings, based on average streamflow conditions, were then applied to determine 33.5 mills for purchases. The contribution margin then took these factors into account in the calculation of net revenue under average water conditions.

The application of these factors results in a gross export revenue calculation of $72.35 million (before transmission and Powerex costs). Providing an adjustment for transmission costs of $5 million and excluding Powerex charges of $8 million, the resultant Electricity Trade Income under average water conditions becomes $59.35 million.

The Commission concludes that the amount of $59.35 million for electricity trade income, under average water conditions, is consistent with the June 30, 1992 determination. In future applications, B.C. Hydro is directed to present a full five year forecast of electricity trade, consistent with the methodology of the 1992 ERC Report.

3.4 Operations, Maintenance and Administration

The 1993 Commission Decision with respect to B.C. Hydro's Revenue Requirement Application stated that:

> "the Commission is concerned about the projected increases in all OMA expenditures, but recognizes that, due to the Special Direction #8 Rate Cap, there is no point in directing B.C. Hydro to amend its forecast for this Revenue Requirement Application. However, B.C. Hydro should recognize that it is at risk for cost disallowances in the future." (p. 35)

That Commission Decision noted that OMA costs had been steadily rising; by 30 percent in 1990, 3 percent in 1991, 10 percent in 1992 and 6 percent forecast in 1993. During that period, the efficiency statistics of OMA costs per customer, customers per employee and GW.h sold per employee had all deteriorated.

The actual results for fiscal 1993/94 were substantially better than that forecast by the Utility at the time of the 1993 Hearing. The $16 million reduction in actual expenditures from forecast may, in part, be a recognition of the Commission's concern for cost control expressed in the 1993 Decision, but the evidence of B.C. Hydro also indicated that the purchase of higher cost energy during the low water conditions in fiscal 1993/94 resulted in corporate directions to reduce OMA expenditures to offset the higher costs (T. 37, 1993 Rate Hearing). This action indicates a view of senior management at B.C. Hydro that OMA expenditures can be reduced.

The OMA forecast expenditure for this fiscal year of $409 million is approximately equal to the $410 million actually spent last year. As previously noted, the bottom up budget process had indicated a desired total budget of $450 million, but the top down executive target setting had constrained the total budget to the $409 million level.

In determining an appropriate level of OMA expense to be allowed for revenue requirement and rate making purposes, the Commission must assess the forecast provided by B.C. Hydro and balance the regulatory objectives to ensure that the Utility provides safe, reliable service at the most efficient costs possible.

Measuring reliability and cost efficiency is consistent with B.C. Hydro's stated mission to become the most efficient utility in North America (T. 22). The Application indicates that B.C. Hydro's average reliability statistics continue to lead CEA averages in most categories (Exhibit 1, p. I-5-D-8). With respect to American utilities, B.C. Hydro stated that comparable statistical measures were not available to measure the extent to which B.C. Hydro compared with the most efficient utilities in the United States.

A more detailed review of the distribution system reliability was undertaken in the Distribution Service Performance Report included in Volume II Related Materials. The report provides a comprehensive analysis of outage and trouble statistics by region and by cause of problem. Outages and trouble statistics for most causes of problems are improving or maintaining a relatively high level of reliability. However, equipment failures and source outages have been increasing. Mr. Threlkeld, Vice President Customer Services, testified that source outages are caused by transmission and substation failures (T. 611). He believed that some of these outages are attributable to faults on the more heavily loaded distribution systems which have backed up into the substation equipment.

Potential problems with respect to reliability and power quality issues between the transmission system and the distribution system have resulted in agreements between Transmission and Distribution units to cooperatively resolve or share in solutions to source outage problems (T. 612). The Commission recognizes that the most recent revision of the B.C. Hydro corporate structure places Transmission and Distribution under one business unit, so that it should be less of an administrative problem to ensure that Transmission and Distribution units work together to resolve any recurrent outage and equipment failure problems that may develop.

The Backlog Maintenance Program is scheduled to be completed in 1995/96 or 1996/97. It remains the expectation of the Commission that this program will phase-out over the next couple of years and that ongoing maintenance will be budgeted for in traditional OMA categories thereafter.

From the evidence, the Commission recognizes that B.C. Hydro is generally maintaining a safe, secure and highly reliable generation, transmission and distribution service. Given this high level of reliability, the Commission has focused on cost control as an issue at this time.

The assessment of the prudency of OMA forecast expenditures is made difficult not only due to the size of B.C. Hydro, but also due to corporate reorganization and changing priorities within the Utility. Intervenors and Commission staff tested the Utility forecasts with respect to overall cost increases in various cost groupings as well as a review of management plans for key business units. One area of concern, explored through Information Requests and at the hearing, related to the large growth of managers and professional staff at the Utility since 1990. The evidence identified that this group had increased from 606 employees to 668 employees, an increase of 17 percent over the past four years (T. 752).

In response to Commission staff Information Request No. 1, B.C. Hydro filed Management Plans for the following business units: Customer Services; Environment, Finance and Administration; Power Smart; Corporate Human Resources; Production; Strategic Research and Development; Chief Engineer Dam Safety; Project Management, Engineering and Construction; Corporate and Strategic Planning; Corporate and Aboriginal Affairs; Economic Development; Chief Information Officer/NCS; and Legal. These plans contained a priority analysis of approximately 20 percent of OMA work activities. Mr. Morris stated that these priority lists indicated the expenses that would be cut first if expenditure reductions were required (T. 796).

In reviewing all of the evidence and testimony from the hearing, the Commission is not satisfied that B.C. Hydro has demonstrated that OMA expenditures are being constrained to a level which will ensure the most efficient operations and lowest OMA costs to customers consistent with the existing high level of reliability. The Commission is of the view that some reduction in overall OMA expenditures is appropriate. The final determination on OMA (inclusive of adjustment to non-utility business charges and IRP costs) is tabulated in section 7.1 of this Decision.

3.5 Finance Charges and Other Expenses

3.5.1 Finance Charges

B.C. Hydro included in its 1994/95 Plan finance charges of $690 million (Exhibit 1, p. I-7-B6.1). These charges are the net costs of debt financing and include earnings on temporary investments and sinking fund income. At the time of the 1994/95 Plan the Utility relied on the 1993/94 fall and winter forecasts for interest and foreign exchange rates contained in the British Columbia Economic Review and Outlook prepared three times a year by the Ministry of Finance and Corporate Relations.

With the release in August 1994 of an updated B.C. Economic Review and Outlook (Exhibit 15) the Utility increased its forecast for finance charges by $35 million to a total of $725 million. The increase was described as being due to higher interest rates and a weakening of the Canadian dollar and was detailed as follows:

Increase in Interest Rates	$11 million
Interim Foreign Exchange	$14 million
Reduced Sinking Fund Income	$10 million

This increased expense was a significant component of the reduction in net income when B.C. Hydro presented its August 31, 1994 updated forecast for the 1994/95 fiscal year.

On page 4 of the revised B.C. Economic Review and Outlook, a graph of Canadian Interest Rates shows an increase in the actual rates of approximately 2 percent in the second quarter of 1994. The new forecast shows interest rates continuing at this higher level throughout 1994 with some easing through 1995 and later. Table 7 in this same report shows a decline in the forecast U.S. exchange rate from $0.75 used in the previous forecast and also used by B.C. Hydro in the 1995/95 Plan, to a figure of $0.722 for 1994 and $0.726 for 1995.

The B.C. Economic Review and Outlook uses the Federal T-Bill and Bond short and long-term rates for forecasting purposes. These are the rates at which the governments of Canada and the U.S. borrow for a specific term. B.C. Hydro then adjusts these amounts to account for the borrowing premium that the B.C. government must pay over these Federal rates when borrowing money on behalf of B.C. Hydro. A table in Exhibit 24 shows that the premium added by B.C. Hydro in its forecasts ranges from 25 basis points for short-term lending, 75 basis points for ten-year and 125 basis point for 20-year Canadian debt. Similar premiums were shown for U.S. borrowings.

The original February 1994 Application filing was made at a time when interest rates were at the bottom of the cycle. In contrast, there is evidence that the updated August 1994 forecast figures may have been prepared at the top of a near-term interest rate cycle (Exhibit 15, p. 4) and that rates may trend downward over the balance of the fiscal year. Exhibit 15 makes it clear that there is little world-wide evidence of renewed inflation, although local impacts such as the Quebec election can result in short-term volatility.

In view of the February position in the interest rate cycle, and in view of the significant capital gains realized by B.C. Hydro through the falling interest rate environment of fiscal 1993/94, it would be understandable if the Utility had been somewhat over-optimistic in its February 1994 estimation of finance charges for fiscal 1994/95. However, it appears to the Commission that B.C. Hydro has been unduly pessimistic in its August re-appraisal of this year's finance charges. On the exchange rate issue, the Canadian dollar is now significantly higher against the U.S. dollar than it was at the time of the August variance report. It is therefore unlikely that exchange rate changes over the full year will produce the $14 million variance predicted (Exhibit 1-7-D5).

With respect to B.C. Hydro's increased borrowing costs, questioning by Commission counsel produced evidence of the highly conservative assumptions made with respect to rate spreads between B.C. Hydro debt and Canadian government securities of comparable terms (Exhibit 24 and 65). For example, on the Utility's 10-year issues, B.C. Hydro has assumed an interest rate spread some 25 basis points higher than the actual current spread after issue costs are taken into account (Reply Argument T. 2830). It is the Commission's view that there is no validity to the use of higher historic spreads in the preparation of a one year prediction of finance charges, even though use of the higher spread may be valid for the purpose of other, longer term forecasts.

The origin of the predicted variance of $10 million in "reduced sinking fund income" is unclear. From examination of the evidence (T. 97) resulting from cross-examination of B.C. Hydro by counsel for the Industrial Customers and as stated in B.C. Hydro's Reply Argument (T. 2833), it would appear to be a result of capital losses experienced on the rollover of securities in the sinking fund. The Reply Argument also identified interest income as a component of this fund. Consequently, one would expect that in a rising interest rate environment, new investments would also provide higher interest income to offset the anticipated capital losses. The Commission is not convinced, on the evidence, that the proposed variance related to sinking funds has been adequately justified.

In addition to earnings on temporary investments and sinking fund income, the net finance charges also include income earned on interest rate swaps. In response to a Commission staff Information Request (Exhibit 2, BCUC 29), B.C. Hydro explained that it utilizes swaps to manage the composition of its debt portfolio between U.S. and Canadian fixed rate and floating rate debt. The Utility stated that studies undertaken by outside consultants for B.C. Hydro have shown that B.C. Hydro's financial risk can be reduced by maintaining a certain balance of Canadian versus U.S. debt, and fixed rate versus floating rate debt.

The evidence showed that B.C. Hydro has been singularly successful in managing these swaps. The earnings from this source have been significant in the past three years resulting in profits of $12 million,

$29 million and $38 million for 1991/92, 1992/93 and 1993/94 respectively (Exhibit 24). For 1994/95 the Company has forecast a loss of $1 million, although Utility witnesses indicated that there were some swaps currently "in the money ... to 17 or 20 million dollars" (T. 262), which at this time were not going to be unwound and the profits realized. The witness further stated that "if the market moved and some of the swaps were in the money, then we may well unwind some of them" (T. 267).

The Commission is concerned with the impact that the revised estimate of finance charges may have on the forecast results of B.C. Hydro. Recent history demonstrates the volatility of financial markets with unexpected peaks and valleys of interest rates and foreign exchange gains and losses. This volatility also impacts on income to be earned from financial instruments which the Company may hold to generate sinking fund income. Consequently, B.C. Hydro could, by the end of the fiscal year, achieve actual results much better than indicated in the August 1994 estimates. The Utility itself did not amend its rate application to account for the higher forecast of finance charges.

On balance, the Commission finds that B.C. Hydro should have revised its Application to reflect a realistic assessment of the increased financial exposure of likely finance charges over the course of fiscal 1994/95.

The Commission determines that the evidence supports an increase in finance charges from the original Application of $10 million, to a total of $700 million.

3.5.2 Other Expenses

Other expenses include taxes, depreciation and amortization and cost of energy. B.C. Hydro revised its forecast of these cost categories in August, 1994 to reflect the following expectations:

$ Millions	Application	August 1994 Update	Change
Taxes	$ 181	$174	($7)
Depreciation and Amortization	287	287	—
Cost of Energy	390	392	2

The update of taxes reflected greater precision since some of the previously forecast tax expense had been realized as actual costs (T. 374).

In the case of cost of energy the expense for water rentals makes up roughly one-half of the total cost of energy expense. B.C. Hydro testified that the more recent forecast cost of energy expense was updated to reflect water rental expenses based on an updated hydro generation forecast (T. 280). The evidence during the hearing did not clarify what the most appropriate cost of energy would be for weather normalized sales.

The Commission determines that the forecast of Other Expenses reflected in the Application should be reduced by $5 million to $853 million.

3.6 Capital and Demand Side Management Expenditures

Capital expenditures by B.C. Hydro on new generation, transmission and distribution plant are recovered in the rates of customers over many years, following the completion of the capital projects. Other capital initiatives, such as new facilities and durable investments like new information technology, are capitalized and recovered in rates over the expected useful life of the investment. So, also, the investments in Demand-Side Management ("DSM") initiatives are recovered over varying time frames reflecting the useful life of the investment.

New capital projects underway in the year of a particular revenue requirement review will typically not show their impact on customer rates until project completion in a subsequent year. However, the carrying charges on investments make up a large portion of the costs that customers must pay for. The 1994/95 Plan shows the Finance, Depreciation and Amortization expense is $977 million, 45 percent of the existing revenue (Exhibit 1, p. I-7-D4).

The Commission must, therefore, pay special attention to the investment plans of the Utility. Integrated Resource Plans which recognize the total cost of alternative investments in new energy supply and conservation alternatives are the critical components which will translate into investments on behalf of customers. The IRP is the driving force behind the establishment of a utility action plan approved by senior management. The capital spending budgets flow out of that action plan and show themselves in customer rates following completion of the project, as depicted in Figure 3.6.1.

Figure 3.6.1

Relationship of IRP to Customer Rates

IRP → Action Plan → Capital Plan → Rates

Table 3.6.1 illustrates the changes in forecast spending for fiscal 1994/95 that have occurred within B.C. Hydro in the last year. In June, 1993 Utility staff indicated a need for $741 million of expenditure in fiscal 1994/95. Expenditure control by management reduced this forecast to $667 million. In September 1994, Utility staff budgeting had reduced forecasts to $607 million and management further reduced the forecast to $575 million. The total decrease in forecasts for fiscal 1994/95 amounts to 22 percent.

The Commission is surprised that such a large variance in forecasts would develop over such a short time frame. However, it is noteworthy that $88 million of the total reduction of $134 million is related to the 500 kV transmission system. This deferral of major transmission spending is consistent with Commission determinations in this Decision that B.C. Hydro should carefully assess all options to postpone major transmission upgrades so that the Utility can assure itself that conservation, industrial rate restructuring or distributed generation will not leave the transmission system underutilized.

Table 3.6.1:

Comparison of the Capital and Demand Side Management Planned Expenditures for 1995

	Exhibit 27 June 29,1993	Exhibit 48 September 19,1994	Difference	% Change
Electric System Plan				
Major Electric System	$233	$145	($88)	-37.77%
Other Generation	$5	$3	($2)	-40.00%
Other Transmission	$5	$4	($1)	-20.00%
Other Substations	$65	$39	($26)	-40.00%
Other Control & Comm	$9	$9	$0	0.00%
Distribution				
Distribution	$205	$206	$1	0.49%
General				
Computers	$37	$32	($5)	-13.51%
Land & Buildings	$24	$21	($3)	-12.50%
Plant Reliability	$20	$26	$6	30.00%
Other	$41	$32	($9)	-21.95%
Other				
Surveys & Investigations	$16	$18	$2	12.50%
Compensation & Mitigation	$4	$7	$3	75.00%
Expenditure Control	($74)	($32)	$42	-56.76%
Power Smart	$67	$57	($10)	-14.93%
Co-generation interest	$10	$8	($2)	-20.00%
Total Capital & Demand Side Management				

with expenditure control	$667	$575	($92)	-13.79%
Total Capital & Demand Side Management without expenditure control	$741	$607	($134)	-18.08%

Table 3.6.2 indicates there is little correlation between the rise in capital expenditures and the increase in gross revenue. Planned expenditures of B.C. Hydro are continually forecast to outpace the growth in revenue by a significant margin. The capital expenditure program seems unrealistic and higher rates would be an inevitable result if the program were to be maintained.

Table 3.6.2:

Capital and Demand Side Management Expenditures

From Exhibit 48	Actual 1993	Actual 1994	Plan 1995	Forecast 1996	Forecast 1997
I-7-A5	585	492	575	625	690
Total Capital and Demand Side Management Expenditures/ % change		**-15.90%**	**16.87%**	**8.70%**	**10.40%**

From Exhibit 1-7-A2 Sales Revenues

	Actual 1993	Actual 1994	Plan 1995	Forecast 1996	Forecast 1997
(in $ millions)	2006	2090	2223	2320	2388
Revenues/ % change		**4.19%**	**6.36%**	**4.36%**	**2.93%**

From page I-7-B2.3 Sales Volumes

	Actual 1993	Actual 1994	Plan 1995	Forecast 1996	Forecast 1997
(in GW.h)	42043	42018	43193		
Domestic Sales Volumes % change		**-0.06%**	**2.80%**		

In the next ten years B.C. Hydro indicated that the system plans require an investment of about $600 million per year (T. 433). The CAC (BC) et al argued that "Clearly, this is an area where cost savings must be pursued." (T. 2627)

According to Mr. Threlkeld of B.C. Hydro, about one-half of the distribution budget of $200 million would be allocated to extending the distribution plant for new customers and the remaining half for reinforcement of the system to permit delivery of the load to new customers (T. 434).

B.C. Hydro stated that the Utility was no longer focusing on the development of large generation additions located far from the load centers. Instead, Integrated Resource Planning forces the Utility to consider smaller generation additions distributed close to areas of new load growth (T. 932 and Exhibit 34, p. 2) Local resource options and local targeted conservative programs will be considered to defer investment in transmission and distribution upgrades. In spite of these claims by B.C. Hydro, the Utility has failed to provide evidence to the Commission in either its capital plan or IRP Action Plan, that it does apply this approach to setting capital budgets.

The Commission instructs B.C. Hydro to make every effort to constrain Capital and Demand-Side Management expenditure for 1995/96 and 1996/97 to $575 million plus a modest escalation related to the increase in customers. If this cannot be achieved, B.C. Hydro is to provide detailed variance reports highlighting the need for extraordinary funding above the allowed level. The Commission further expects that the major investment categories of generation, transmission, substations, distribution, plant reliability, surveys and investigations, and Power Smart will have been reviewed as part of the IRP.

One area of significant new capital expenditure will be for Information Technology ("IT") and a new Customer Information System. B.C. Hydro has recognized this area and provided a report by Deloitte & Touche which made recommendations for B.C. Hydro's development of IT systems. **Given the past experience with Dafron, the recent experience of BC Gas with Theseus and the cautionary conclusions of Deloitte & Touche, the Commission expects B.C. Hydro to complete a full review of its IT needs before making major financial commitments. B.C. Hydro is to keep the Commission fully informed of its IT plans in advance of major expenditures.**

3.7 Westech Information Systems Inc.

Westech Information Systems Inc. is one of two subsidiaries created in 1989 from the Utility's Computer and Management Systems Division. The subsidiary was later privatized. B.C. Hydro transferred the division's assets to Westech, which purchased a contract from the Utility to deliver services including the design, development and maintenance of the computer system, for a pre-determined rate structure (T. 757). B.C. Hydro then undertook to supply a minimum level of work, amounting to $18 million in fiscal 1994/95, decreasing over the next six fiscal years to approximately

$13 million (Exhibit 10, CIO Group Business Plan). Western Integrated Technologies Inc., the other company formed from the separation of the Computer and Management Systems Division, also had a guaranteed minimum revenue contract. It was re-absorbed into B.C. Hydro after a task force recommendation in 1992.

In 1992, the Management Services Division was commissioned to conduct an operational review of the Westech service arrangement (Exhibit 30), which showed that the anticipated volume of B.C. Hydro and BC Gas work for Westech was significantly lower than expected and that the guarantee clause could lead to inefficient decisions in the future. The report also found that there may be an unintended practice developing towards rehiring skills in-house, since there was no mechanism to determine what type of skills are legitimately required within the Utility. Estimates of the number of people doing "Westech" work varied from 100-200 employees. Mr. Harrison only partially agreed with the assessment, pointing out that the information technology area has changed substantially since Westech was privatized (T. 761). The Westech contract calls for an annual 5 percent improvement in productivity, which the review team concluded is low compared to the levels being reached by others. B.C. Hydro did not provide the results from its productivity measurement efforts.

An Executive Summary of the Management Response to the operational review was filed as Exhibit 31. Although B.C. Hydro did not provide the full response and action plan, the Summary indicates that, while management concurred in varying degree with the detailed findings, it established another task force in November 1993. The possible directions that could result are a "partial or complete buy-back of Westech, or a re-negotiation of the Service Agreement." Mr. Harrison did not know the status of this task force. The other major component of the action plan was "establishment of the enterprise-wide information management framework." This framework assumes the B.C. Hydro guarantee will continue and will be commented on by the Deloitte & Touche information technology review (T. 768).

B.C. Hydro agreed to provide the Commission with any new contract entered into with Westech, subject to any required confidentiality. The Intervenors accepted the need for general confidentiality but felt that part of the Commission's mandate is to monitor these activities for the benefit of ratepayers. The Industrial Customers urged the Commission to require B.C. Hydro to eliminate costly duplication of service.

The determination of B.C. Hydro's IT strategy will have a direct impact on Westech. As part of the report to the Commission on IT strategy, B.C. Hydro is to detail the role of Westech.

3.8 Telecommunication Facilities

A number of B.C. Hydro's management plans refer to the possibility of a greater involvement in the telecommunications business, attracting the attention of both the Industrial Customers and CAC (BC) et al. The Utility's response to questioning on this issue was that it was looking mainly at reducing its own costs but that it had not dismissed more active roles, such as becoming a carrier (T. 62). While a considerable amount of work has been done, B.C. Hydro says it will be two or three years before any major expenditures are incurred (T. 82).

According to Exhibit 48, the Telecommunication Upgrade Project being studied by B.C. Hydro estimates total capital costs in the $120 million range, with installations over the 1996 - 2002 time frame. Its detailed planning phase, to be completed by June 1996, is budgeted at $2.7 million. The forecast of Information Technology capital spending for 1994/95 shows the Plan has been reduced from $32 million but that some $15 million is still expected to be incurred by the end of the year (Exhibit 24).

Like the Intervenors, the Commission is satisfied that B.C. Hydro is pursuing cost reduction and possible partnership opportunities, but is concerned about expenditures outside the Utility's primary area of expertise. The Commission directs B.C. Hydro to report on its efforts to engage in partnership or other cooperative arrangements with telecommunication companies before committing to major investments in telecommunication facilities for its own use.

3.9 Contributions in Aid of Construction

All utilities in British Columbia have an obligation to extend service to new customers located in their service territories. The Commission has approved conditions for such extensions so that utilities will pay up to a specific level of extension cost. Any additional cost is paid for directly by the customer so that new extensions are not subsidized by existing ratepayers. The normal regulatory practice employed by the Commission is to deduct the amount paid by the new customer (generally known as a Contribution in Aid of Construction) from the rate base of the utility. An alternative accounting treatment is to show the full cost of the extension as part of the cost of utility assets and to identify the amount of the customer contribution as zero cost capital funding, thereby neutralizing that part of the utility asset directly funded by the customer. The intent is to avoid customers being charged for assets that they have paid for.

In the case of B.C. Hydro, Special Direction No. 8 requires that contributions in aid of construction be recognized as equity in the Utility capital structure, resulting in all customers having to pay a return on equity to the Utility for that part of a customer extension which is directly funded by the customer. The Industrial Customers argued that this requirement of Special Direction No. 8 is punitive to the consumers of electricity from B.C. Hydro. In final argument, the Industrial Customers urged the

Commission to require B.C. Hydro to discontinue the practice of requiring contributions in aid of construction which, under Special Direction No. 8, impose hardships on new parties attaching to the system, without any benefit for existing customers.

The Commission agrees with B.C. Hydro that contributions in aid of construction should not be discontinued.

3.10 Construction Business Unit

During the hearing, a significant amount of attention was given to the B.C. Hydro Construction Business Unit ("CBU"), both by Commission counsel and through the intervention of the Electrical Contractors Association of B.C. ("ECABC"). B.C. Hydro's Corporate Policy Statement 06.1.01 describes the roles and responsibilities of the CBU.

The Policy states in part:

> "CBU, operating as a service business unit within an integrated electrical business, will function as a cost effective internal resource providing a broad scope of flexible, mobile and emergency response construction services."

The Policy further states:

> "CBU is available to complement the permanent B.C. Hydro resources, the contractor resources in the community and, in a "general contracting" structure, utilize private sector resources to ensure effectiveness and efficiency of services/products provided." (Exhibit 4-ECABC 1-1)

The Policy is accompanied by a series of functional guidelines. The Commission is of the opinion that the guidelines are so broad that they can be interpreted to cover almost any eventuality and B.C. Hydro appears to be giving them the broadest possible interpretation. With reference to the guidelines:

1. The Commission does not accept that it is necessarily more cost effective to use the CBU rather than outside contractors on ill-defined projects. It may be easier and cheaper to supervise the CBU but that does not make the supervision economically effective if the end cost is higher than it would have been with a carefully supervised contractor operating under properly prepared change orders.

2. There was no evidence that the CBU is better able to utilize innovative work methods than a private contractor. Logic would suggest that a private contractor whose economic survival was at stake would have an even greater incentive to be innovative.

3. No evidence was provided as to how the level of work assignment to the CBU necessary "to retain a core nucleus of unique or specialized expertise" was determined. It appears that this directive is used to justify a workload requiring maintenance of a steady complement of long-term temporary employees, working about 70 percent of the time on average, doing some 60 to 70 percent of all B.C. Hydro's line work (T. 638, Exhibit 4, ECABC 6-1). This goes much further than "to complement the contractor resources in the community" as stated in the Policy.

Intervention by the ECABC took the form of cross-examination of B.C. Hydro's witnesses and evidence from an ECABC panel of witnesses. The main thrust of the intervention was focused on line work performed for B.C. Hydro but other work areas were indicated (T. 1050). The ECABC contended that more linework should be contracted out to the private sector in order to reduce B.C. Hydro's costs and thereby benefit ratepayers (T. 1038). B.C. Hydro did not agree that the contractors' costs were any lower than those of the CBU. In answer to an Information Request from the ECABC, the Utility provided a detailed operations budget for the CBU, including overheads, for the 1994/95 Plan (Exhibit 4, ECABC 2-2). No information was provided on the targeted number of hours or percentage of workload covered by this budget. Witnesses for the CBU testified that the contractors, as well as the CBU and B.C. Hydro's internal crews, provide valuable competition and that a healthy tension is necessary amongst contractors, the CBU and Hydro's internal crews in order to achieve optimal efficiency (T. 662).

While the Utility testified that it liked to see a healthy tension between the private sector and the CBU, its policies do not permit direct competition by open bidding between the CBU and contractors. In the absence of such direct competition, the competitiveness of the CBU cannot be determined and B.C. Hydro is unable to demonstrate the prudency of expenditures on work assigned to the CBU.

The Commission accepts that it is important to B.C. Hydro that it retains a nucleus of in-house capability to undertake work of a specialized or an emergent nature or where system outage constraints dictate close liaison with operating systems staff. A witness for B.C. Hydro described in some detail the nature of specialized or emergent work that does occur (T. 644). B.C. Hydro also testified as to its belief in the importance of the role played by private sector contractors. Significant fluctuation in the work load is bound to occur and this is accomplished with the use of private sector contractors and by having most of the employees in the CBU retained as temporary employees (T. 638).

The Commission concurs that it is in B.C. Hydro's best interests to have competent contractor resources available in the communities. In order to ensure a viable resource, the private sector must have sufficient business from B.C. Hydro to maintain the equipment and skilled labour required to perform the work efficiently and effectively.

The Commission instructs B.C. Hydro to bring forward a formal policy which would annually allocate a target percentage of line and wire work (on a dollar basis) to both the contracting industry and to the CBU, with the balance of work being opened to competitive tendering by both the CBU and the contracting industry. The Commission suggests that a one-third assignment of B.C. Hydro's annual work load in each category may be appropriate. Justification should be provided for the chosen apportionment. In any case, a sufficient volume of work shall be offered to competitive tenders involving the CBU to demonstrate its competitiveness. The Commission notes that, because the CBU relies extensively on long-term temporary employees, this suggestion should have no material impact on the Utility's full-time employees.

At least the following key guidelines should be incorporated into the competitive tendering process between the CBU and the Contractors:

1. A formal "engineer's estimate", based on the tender documents, shall be disclosed to all parties at the time of tender opening.

2. CBU tenders should identify at least those components of the bid set out in Exhibit 4, ECABC 2-2.

3. Subsequent changes in the nature or scope of the work shall be documented in formal change-orders and subject to written quotations by the successful bidder, whether CBU or private contractor, and all such costs identified in final project cost reports.

4.0 INTEGRATED RESOURCE PLANNING

4.1 Introduction

In Spring 1993, the Commission issued its Integrated Resource Planning Guidelines ("the Guidelines") and directed utilities under its jurisdiction to submit draft IRPs by December 31, 1993 unless otherwise instructed. By letter dated March 22, 1993, B.C. Hydro informed the Commission that it believed its 1992 Electricity Plan met the general requirements of an IRP. Accordingly, the Commission reviewed the Plan and related documents for consistency with the elements of IRP, as set out in the BCUC Guidelines.

During the course of the 1993 B.C. Hydro Revenue Requirements hearing, evidence was given which indicated that the Electricity Plan was reasonably consistent with general IRP principles, that the models and basic methodologies used to forecast electricity load were capable of providing accurate forecasts and that the estimated cost of new electricity supply was useful as a resource screening tool in an IRP context. However, a number of areas were noted in which the Electricity Plan needed to be improved to better meet the requirements of IRP. These included: (1) a clearer statement of IRP objectives; (2) increased documentation of the load forecasting methodology and an increase in the range of forecasts generated; (3) identification of all resources considered by the Utility in its planning process not only those which form part of the preferred portfolio; (4) increased characterization of resources and the selection process used to choose amongst resources to generate the preferred resource portfolio; and (5) increased public participation at an earlier stage of the planning process.

Subsequently, in its Decision dated December 7, 1993, the Commission directed B.C. Hydro:

> "to make those changes which are necessary to convert the current Electricity Plan into a full Integrated Resource Plan and to file such Plan under its new name by June 30, 1994. Alternatively, if the Utility believes there is a need for the Electricity Plan as currently prepared, it may produce two documents: the current Electricity Plan and an IRP. In making this direction, B.C. Hydro is reminded that one of the purposes of IRP is to facilitate communication between the utility and those interested in the utility's resource planning activities.
>
> In addition, B.C. Hydro is reminded that the IRP provides the focal point for justification of future capital projects which the Utility may wish to undertake. As a result, the IRP should contain sufficient information to allow non-utility parties to understand the Utility's objectives and to follow the Utility's reasoning in arriving at its decisions. In particular, the IRP should clearly explain the process and justification by which the Utility has arrived at specific resource acquisition and development decisions. This information will be considered in future when the Commission reviews the prudency of B.C. Hydro expenditures. It is expected that the Utility's IRP will generally conform with the Commission's Guidelines and, where not in conformity, the Utility will explain and justify the reasons for deviation.
>
> In addition, the Commission suggests that B.C. Hydro expand the mandate of the DSM collaborative to embrace a broader IRP focus. With the wider mandate, the collaborative could consider social costing and how it should be used within the IRP process. At present, the Commission does not find the link between the Utility's social costing initiatives and its IRP initiatives to be clear. Alternatively, B.C. Hydro may wish to institute some other process to achieve the goal of full stakeholder participation in IRP. The Commission leaves the exact mechanism to the discretion of the Utility but expects

to see this public consultation objective achieved, with a report to the Commission by June 30, 1994." (p. 42)

On June 30, 1994, B.C. Hydro submitted the following documents: (1) the 1994 Electricity Plan; (2) the 1994 Electric Load Forecast; (3) the Resource Acquisition Policy; (4) the 1994 Cost of New Electricity Supply; and (5) the Electric System Plan. In the accompanying letter (Exhibit 34), the Utility indicated that these documents, together with a Public Participation Program ("IRP4") scoping document and a Technical Appendix which they planned to file by August 31, 1994, constituted the IRP. These latter documents were filed as scheduled. Together with the previous documents, they were examined during the course of this hearing to determine if the necessary improvements had been achieved.

4.2 Objectives

BCUC Guideline #1 calls for the identification of the objectives of the IRP. As indicated above, in the last hearing B.C. Hydro was criticized for not providing a clear and explicit statement of its IRP objectives. In the 1994 Electricity Plan, B.C. Hydro set out six long-range planning objectives as follows:

1. Identify and evaluate all potential demand-side and supply-side resource options.

2. Rank resource options on the basis of their social and environmental impacts as well as their economic costs and benefits.

3. Maintain reliability of supply by ensuring the availability of existing resources and developing new resources as required to meet customers' needs for electricity services.

4. Minimize risk by explicitly incorporating key uncertainties into planning analyses and by identifying options which enhance planning flexibility.

5. Advise the public and others of B.C. Hydro's plans and the factors which affect those plans. Integrate public input into the selection of new resources.

6. Support the attainment of current corporate objectives and strategic initiatives. (Exhibit 32, Electricity Plan, p. 3)

In addition, B.C. Hydro identified five specific objectives to be achieved within the 1994 Electricity Plan. These included:

1. Re-examine the outlook for resource acquisitions based on developments since the December 1992 Plan (Section 1.2).

2. Describe B.C. Hydro's current Resource Acquisition Policy and incorporate this Policy into the evaluation and selection of new resources.

3. Identify the risks and uncertainties associated with individual resource options and with alternative resource sequences.

4. Identify action items which are required to maintain flexibility and reliability given current risks and uncertainties.

5. Communicate B.C. Hydro's current plans to its customers and other stakeholders in order to make them available for public discussion. (Exhibit 32, Electricity Plan, p. 3)

Finally, B.C. Hydro stated that it had developed five corporate objectives which had also influenced the development of the Electricity Plan and which were intended to reflect society's values in B.C. Hydro's decision making. These included:

1. To be a leader in the economic and social development of British Columbia.

2. To be a leader in the stewardship of the natural environment.

3. To be the most efficient utility in North America.

4. To be a superior customer service company.

5. To be the most progressive employer in British Columbia. (Exhibit 32, Electricity Plan, p. 6).

B.C. Hydro recognized the importance of setting objectives, stating that IRP begins with objectives, defined by the planner, which are well-defined, measurable and well-understood by all participants in the planning process (Exhibit 32, Technical Appendix, p. 2-4). B.C. Hydro's current IRP objectives are not developed with direct public input.

There was significant discussion at the hearing concerning the linkage between IRP and broader corporate and strategic planning. B.C. Hydro stated that the corporate goals, described in the document, The Way Ahead, were established by the Board of Directors, without input from senior management (T. 135). In response to a question as to how the corporate objectives had influenced the development of the Electricity Plan, B.C. Hydro indicated that some reflection of corporate objectives was given in the multiple account evaluation categories, particularly as they related to job creation and economic development, but that they did not influence the selection of the preferred resource portfolio per se (T. 2113).

With respect to how the Electricity Plan influences the corporate and strategic plan, B.C. Hydro stated that the Electricity Plan is provided to the Board of Directors to give them information on the potential activities of the corporation over the planning horizon, typically 20 years. This information is used as well by a variety of groups within B.C. Hydro, for example Power Smart, to give them an indication of likely activities over the foreseeable future which is then employed to develop bottom up requests for budget (T. 1073).

B.C. Hydro stated that they ensured that there was consistency between The Way Ahead and the Electricity Plan by looking to see whether the Electricity Plan met the objectives of The Way Ahead (T. 1078). The Utility has no plans to factor integrated resource planning into a new strategic plan in a more explicit way (T. 2268).

Commission Determinations

As indicated in the Commission's Guidelines, a clear and explicit statement of objectives is essential to IRP. These objectives form the basis against which potential resource acquisitions are evaluated. As a result, there should be a clear link between the stated objectives, the characterization of potential resources, and the subsequent development of resource portfolios. Although B.C. Hydro specified a variety of objectives, no such clear link to the preferred portfolio was demonstrated in the 1994 Electricity Plan.

Subsequent IRPs must explicitly demonstrate how the objectives contributed to the selection of the preferred portfolio.

With respect to the actual objectives identified in the Electricity Plan, the Commission is concerned that the lack of public involvement undermines the credibility of the chosen IRP objectives.

The Commission directs B.C. Hydro to review the objectives given in this Plan with the new IRP consultative committee, established pursuant to the directions given below in Section 4.7 of this Decision.

Such review could result in a recommendation for deletion, addition or amendment to the objectives presented in this Plan. The final determination of objectives continues to rest with B.C. Hydro's management and Board of Directors.

In addition, the Commission is concerned that B.C. Hydro apparently has no plans to factor IRP into its broader planning processes in a more explicit manner. As indicated in BCUC Guideline #7, the development of a set of preferred resource portfolios through the IRP process should lead to an Action Plan consisting of those steps which need to be initiated over the near future in order to meet the most likely gross demand forecast. In turn, the Action Plan should be used to generate the Utility's necessary capital budget which contributes to the determination of the utility's rates. This is the most effective means for the Commission to assess the prudency of the capital component of future rates. The relationships between the IRP, the Action Plan, capital budgets, and rates are outlined in Section 3.6, and depicted in Figure 3.6.1.

The Commission directs B.C. Hydro to file its IRP and Action Plan no later than June 30, 1995. Further, the Commission directs B.C. Hydro to ensure that all future capital plans are based on the IRP and Action Plan. The Commission notes that the capital plans for 1995/96 will be prepared prior to the next complete iteration of the IRP but expects B.C. Hydro to clearly link them to the IRP as it stands at that time.

The Commission requires B.C. Hydro to file this information whether or not the Utility has applied for a revenue requirement increase. In the absence of such filing, the Commission may decide, on its own initiative, to launch a revenue requirement review at which the Utility would be at risk concerning the prudency of its expenditure decisions, including capital items that had not been justified within the IRP.

4.3 Development of a Range of Gross (Pre-DSM) Demand Forecasts

BCUC Guideline #2 calls for the development of a range of gross (pre-DSM) forecasts, in order to address uncertainty, that can distinguish between demographic, social, economic and technological factors unaffected by Utility actions, and those actions the Utility can take to influence demand. Further, the Guideline states that gross demand forecasts should be structured in such a way that the savings, load shifting or load building due to DSM resources can be allocated to specific end-uses in the demand forecast. B.C. Hydro's load forecasts and the methodologies used to derive them are described in the Electric Load Forecast Document (Exhibit 32, Electric Load Forecast 1993/94 - 2013/14). The forecasts cover a 20 year horizon for each of the residential, commercial, and industrial sectors, are gross, (i.e. pre-DSM), and are based on an end-use methodology for each class of customer.

B.C. Hydro has identified two major components of uncertainty in the long-term load forecast. These are: (1) uncertainty in the future levels of major causal factors and their effect on future electricity consumption levels; and (2) uncertainty about how the relationships between the major causal factors and electricity consumption may change over time (Exhibit 32, Electric Load Forecast, p. 10-1).

The five major causal factors of uncertainty are: (1) the long-term economic growth rate; (2) the electricity rate; (3) the effective energy reduction achieved by DSM; (4) the response to electricity price change (price elasticity); and (5) the electricity intensity.

Using probability distributions for each of the five causal factors and Monte Carlo simulation methods, the Utility established a probability distribution which showed the various loads which could be expected from various combinations of the five factors. A reduced band of forecasts was then established for which there is only a 10 percent chance that the actual load, on a normalized basis, will be lower than the low case or higher than the high case, due to these factors.

To further test uncertainty, B.C. Hydro assessed two additional potential scenarios. The first looked at the impact of dispersed generation and the second looked at the impact of electric vehicles. B.C. Hydro stated that these two scenarios were addressed within the Electric Load Forecast Document since the information was already available, but not within the Electricity Plan since the treatment of the low demand forecast outcomes within the Electricity Plan was intended to cover these additional scenarios (T. 2127, 2134).

The forecasts are presented on a system-wide basis rather than disaggregated by region, although some of the data used to develop the forecasts and some of the initial work to build the forecast is on a regional basis. B.C. Hydro stated that it plans to enhance its ability to undertake regional forecasts and has a number of projects devoted to this end. To date, the main emphasis on a regional forecast has been in the area of capacity planning, to allow the Utility to develop its capacity forecast in a more direct manner rather than as an offshoot of its energy forecast. B.C. Hydro stated that development of regional forecasts would not preclude the need for system-wide forecasts since "the capacity demand on the system is not equal to the individual capacity demands on components of the system", due to diversity with respect to peak demand between regions (T. 2121). Further, the Utility noted that there may be a tendency to prefer system-wide information since it would ensure consistency of assumptions between regions (T. 2122).

Commission Determinations

The Commission finds that the general methodology employed by B.C. Hydro in developing its electric load forecasts is consistent with the Commission's Guidelines. However, the Commission is concerned that insufficient use is being made of scenario analysis to analyze the risks faced by the Utility.

The Commission instructs B.C. Hydro to consult with the new IRP consultative committee to develop appropriate scenarios to enhance its assessment of the risks faced by the Utility.

The Commission supports B.C. Hydro's efforts to develop regional forecasts and encourages the Utility to continue to do so.

4.4 Identification of Supply and Demand Resources

BCUC Guideline #3 calls for all feasible individual supply and demand resources, whether committed or potential, to be identified. B.C. Hydro groups its supply and demand generation resources into existing, committed and potential categories. Existing resources are those currently in use on the B.C. Hydro system. The Utility defines resources as committed if they are substantially complete or if the Utility anticipates no major roadblock to their approval (T. 2283).

A comprehensive list of potential generation resource options, including ones from both the demand-side and supply-side of the resource stack, was also supplied by the Utility. B.C. Hydro recognized that some of these resources may be developed by Independent Power Producers ("IPPs") rather than by the Utility directly (Exhibit 32, Electricity Plan, Section 5).

The primary resource identification focus within the Electricity Plan is on generation resources; however, the Utility recognizes that the IRP process is also applicable to transmission planning. Options such as local generation, DSM, voltage control devices, remedial actions schemes as well as new transmission lines were identified as methods of meeting customer transmission and distribution needs (Exhibit 32, Electricity Plan, p. 35).

Commission Determinations

The Commission is satisfied that B.C. Hydro has identified feasible supply and demand resources as they relate to generation. The Commission is concerned that more work is necessary to identify feasible transmission options, including distributed generation and regionally specific conservation, since the option of adding substantial new transmission lines will be costly and could possibly place the Utility at risk from new technologies of conservation and distributed generation.

The Commission instructs B.C. Hydro to undertake such activities as are necessary to more fully identify transmission and distribution options under varied scenarios.

4.5 Characterizing Supply and Demand Resources

4.5.1 <u>The Resource Acquisition Policy</u>

BCUC Guideline #4 states that each supply and demand resource must be measured against a consistent set of attributes, which may be either quantitative or qualitative. If quantitative, the attributes may be either monetized or non-monetized. Suggested attributes include utility and customer costs, social and environmental impacts, risk and whether the resource constitutes a lost opportunity. The Guidelines define lost opportunities as opportunities, which if not exploited promptly, are lost irretrievably or rendered much more costly to achieve. It is expected that the selected attributes will reflect the chosen IRP objectives. To aid the characterization of resources, B.C. Hydro developed its Resource Acquisition Policy ("RAP") which outlines the factors the Utility takes into account when evaluating resource options. The six evaluation accounts used to describe or characterize resource options are: (1) B.C. Hydro Corporate Cost (2) Customer Cost; (3) B.C. Government Account; (4) Environmental Impacts; (5) Community/Social Impacts; and (6) Economic Development Impacts. It is assumed that the aggregate of the B.C. Hydro Corporate Cost, Customer Cost, B.C. Government Account and monetized externalities would equal the social cost estimate shown in the Technical Appendix Resource Summary Data Sheets.

The RAP reflects B.C. Hydro's interpretation of the Provincial Government's October, 1992 Policy Statement on Independent Power Supply which directed the Utility to develop evaluation procedures to rank electricity resources in terms of their social benefits and costs and to acquire resources on the basis of need (Exhibit 32, RAP, p. 1). B.C. Hydro stated that the RAP is consistent with the Crown Corporation Secretariat's Multiple Account Evaluation ("MAE") Guidelines and the BCUC IRP Guidelines (Exhibit 32, RAP, p. 1). The RAP was developed without the benefit of extensive formal public involvement, although the Utility has received unsolicited feedback and an earlier iteration of the policy was the focus of a late 1992 workshop (T. 2409).

Although the RAP identifies six specific accounts which are to be used to evaluate resources, the identification of specific attributes used to evaluate all resources appears to be limited to attributes which can be monetized (T. 1102). For example, the attribute associated with the Corporate Cost Account is the direct cost to B.C. Hydro of acquiring the resource, while the B.C. Government Account identifies applicable transfer payment benefits to the province and any direct costs incurred by provincial or regional governments or other Crown agencies which are not already internalized into the cost of the project (Exhibit 32, RAP, p. 4). It was not clear how B.C. Hydro intends to account for non-monetizable attributes.

The Environmental Account includes Air Emission Costs and Land and Water Use Impacts. Local air emission costs related to Nitrogen Oxides (NOx), Sulphur Oxides (SOx) and Total Suspended Particulates were monetized based on Bonneville Power Administration ("BPA") damage cost estimates, scaled to reflect population (Exhibit 32, RAP, p. 5). Mr. Bruce Biewald, a witness appearing for the Energy Coalition expressed concerns that: (1) the values for NOx and particulates were low in comparison with values used by other provinces and U.S. states; (2) the use of population scaling insufficiently valued damage to pristine areas; and (3) the values were based on damage cost estimates which made no allowance for uncertainty, neglected certain pathways and receptors, and relied on estimation methods which were difficult both practically and conceptually (Exhibit 43, pp. 6/7). The witness recommended that the damage cost approach be replaced with a control cost approach. Although he recognized that some of the weaknesses identified for the damage cost approach also applied to the control cost approach, he stated that the control cost approach deals explicitly with risk and does not require the identification of all the pathways, receptors and impacts that is required by the damage cost approach (T. 1265).

In response to these criticisms, B.C. Hydro indicated that the damage cost approach had been chosen since this approach attempts to quantify the actual loss to society associated with the environmental damage (T. 1161). With respect to the valuation of pristine areas, B.C. Hydro indicated that this value would be incorporated into a multiple account evaluation in a qualitative manner, rather than through the monetization of externalities (T. 1159), since such values are difficult to monetize (T. 815).

B.C. Hydro monetized greenhouse gases using a cost of control approach based on tree planting. The cost of CO_2 was estimated at $15 per tonne while the cost of methane was estimated at $165 per tonne. B.C. Hydro stated that the control cost approach was chosen since the impacts of greenhouse gases are considered to be global (Exhibit 32, RAP, p. 6). The witness for the Energy Coalition recognized that the use of the $15 per tonne value was a significant first step which made the Utility a leader in this aspect of energy planning, but suggested that the value used by the Utility might be low (Exhibit 43, p. 11). The witness suggested that B.C. Hydro use a target control cost approach in which the control cost is estimated to be the price of the highest cost (or marginal) option necessary to meet the target (Exhibit 43, p. 8). The witness indicated, that while tree planting could turn out to be the marginal cost, it likely would not (Exhibit 43, p. 13). B.C. Hydro agreed that $15 per tonne might not be the marginal cost of abatement but indicated that it was chosen as it was a feasible abatement option (T. 1237). There was no indication that B.C. Hydro was actively considering planting trees (T. 1239).

There was also discussion about the treatment of CO_2 with respect to wood waste projects. Currently, the RAP calls for wood waste projects to be treated as if the project emitted no CO_2 since the waste would release CO_2 into the atmosphere if allowed to decompose naturally (T. 1916). B.C. Hydro agreed that burning results in faster deterioration than if allowed to decompose naturally (T. 1917). One Intervenor, Ms. Bechler, suggested that the time frame within which the CO_2 was released was important, that wood waste provides nutrients and other essentials for the next generation of trees and that we leave too little waste to provide for succession (T. 2823).

The CAC (BC) et al argued that the Commission should order B.C. Hydro to commission a study, to be overseen by a collaborative, to provide recommendations on appropriate ranges of values for CO_2 emissions, with the report being due no later than one year from the date of this Decision. As an interim measure, the CAC (BC) et al suggested that the Commission direct B.C. Hydro to substitute the figure of $32 per tonne of CO_2, which was the Federal Department of Finance estimate of a required carbon tax (Exhibit 43, p. 24), in place of the $15 per tonne value used (T. 2623).

The lack of a consistent set of non-monetized attributes for other environmental impacts, community and social impacts, and economic development impacts, against which all resources would be evaluated, was a source of concern raised during the hearing. B.C. Hydro indicated that it would ensure consistency in the evaluation of resources by making sure that all items relevant to the evaluation of a resource were identified and that the resource evaluation summary sheets were widely reviewed (T. 2220).

4.5.2 Application of the Resource Acquisition Policy - Existing Resources

A second area of concern raised during the hearing was the extent to which the RAP had been applied consistently to characterize all resources, existing, committed and potential. With respect to existing resources, most of the questions asked concerned the criteria B.C. Hydro used to establish water levels for existing reservoirs. Mr. Rick Berry, speaking in support of the Williston Lake 2150 Task Force, stated that B.C. Hydro had indicated that it had plans to draw the Williston Lake reservoir down to unprecedented levels, i.e. below 2150 feet. Mr. Berry submitted that this would cause pulp and paper mills, saw mills and barging operations to cease operations, leading to the direct loss of approximately 1,500 jobs. There would also be indirect adverse economic effects (Exhibit 39).

B.C. Hydro stated that its existing water license allowed the Utility to draw down the Williston reservoir to 2,106 feet from its normal maximum elevation of 2,205 feet. In determining exactly how low to draw down the reservoir within the constraints of the water license, B.C. Hydro indicated that it had to consider the impacts on other reservoirs as well as the cost of energy from other resources it might have to acquire in order to offset the energy lost from Williston (T. 825). The Utility stated that the Electric System Operations Review, undertaken for the provincial government (T. 828), indicated that there would be severe cost impacts on the power system by restricting the level of drawdown on the Williston reservoir to 2,150 or 2,130 feet (T. 838).

The Utility recognized that it used different criteria to operate its system than it used to make resource acquisition decisions, in that it considered social costs for resource acquisition but not for resource dispatch. However, B.C. Hydro stated that it had a government directive with respect to the former and while it might be willing to take social costs into account on its own initiative if the monetary impacts were small, if there were dramatic rate impacts it would want a directive from the government before self-imposing operating restrictions which were tighter than those in its existing licenses (T. 2139). Accordingly, B.C. Hydro indicated that, if the people living near the Williston reservoir wished to guarantee that the reservoir would not be drawn down to such low levels, they should ask the government to change the water license (T. 829).

4.5.3 Application of Resource Acquisition Policy - Committed Resources

With respect to committed resources, the RAP appears to have been applied selectively. B.C. Hydro indicated that Resource Smart projects, by their nature, had minimal environmental impacts so that they could be evaluated on project cost relative to each other (T. 2176). Similarly, most Power Smart programs were not subject to a multiple account evaluation, although B.C. Hydro indicated that they would be subject to a multiple account evaluation as each program came up for re-approval. B.C. Hydro stated that the RAP was a recent development and that they were unwilling to stop all programs to carry out a multiple account evaluation. Instead, Power Smart programs had been evaluated using the Total Resource Cost ("TRC") test (T. 1106); however, the TRC does not include social costs and benefits.

The Electricity Plan also treats supply arising from the Alcan Purchase Agreement and the Alcan Completion Project and Coordination Agreement as committed. These contracts were entered into by B.C. Hydro and Alcan in February, 1990 and were expected to commence by January 1, 1995, with terms of 20 years and 50 years respectively. Currently, the Kemano Completion Project ("KCP") is not expected to be on line before January 1, 1998 (T. 820); however, Alcan has indicated its intention to deliver electricity under the long-term purchase agreement regardless of the status of the KCP. B.C. Hydro indicated that Alcan may have to source that power from a third party or reduce the load at the smelter in order to meet this obligation. The Utility recognized that such an action might not be in the best interests of the province and expressed a willingness to work with Alcan should such an eventuality arise (T. 1462). B.C. Hydro stated that the coordination agreement is unlikely to become effective until KCP is in service.

The Resource Summary sheet included in the IRP Technical Appendix indicates that B.C. Hydro considers the environmental and social costs associated with supply from Alcan to be Alcan's responsibility (Exhibit 32, Technical Appendix). Accordingly, B.C. Hydro did not subject these agreements to the multiple account evaluation described in the RAP. In support of this position, B.C. Hydro stated that it signed the Agreements in 1990 after the signing of the "Settlement Agreement" between Alcan and the governments of British Columbia and Canada. The Utility assumed that this meant that the provincial government had decided that KCP was in the public interest. Therefore, B.C. Hydro concentrated its efforts on negotiating a contract in the best interest of its customers (T. 1120). Additionally, B.C. Hydro indicated that undertaking multiple account evaluation of the contracts was not feasible since a commitment had been made and it was not normal practice to back out of a signed contract. Nonetheless, in response to a question by Mr. Tarnoff, B.C. Hydro conceded that, if it was in the best interests of B.C. Hydro to try and change already negotiated contracts, it was theoretically something that could be considered (T. 1770). B.C. Hydro stated that if it were starting with a "blank piece of paper", it might do a more rigorous analysis before including this particular project in the list of preferred alternatives (T. 1121). Mr. Tarnoff suggested that the Commission direct B.C. Hydro to estimate the social and environmental costs of the Alcan power purchases and re-assess its status as a committed resource (T. 2791).

The Electricity Plan considers the Downstream Benefits from the Columbia Basin ("DSBs") to be a committed resource, although there is considerable uncertainty related to the DSBs availability to B.C. Hydro. The Utility stated that it understood that the provincial government's intention was to maximize the value of the benefits. B.C. Hydro indicated that it expected to be the purchaser of last resort for the benefits since its avoided cost was lower than that of other utilities, so that the province could maximize benefits by selling to others (T. 1464). As a result, B.C. Hydro presented its forecast firm energy and dependable capacity balance both with and without the return on the treaty entitlement (Exhibit 32, Electricity Plan, pp. 32/33).

4.5.4 Application of Resource Acquisition Policy - Potential Resources

With respect to the evaluation of potential resources, B.C. Hydro stated that it attempted to focus its evaluation activities to the level of analysis that appeared to be warranted by the project. If a preliminary screening indicated that a particular project was so uneconomic or otherwise undesirable that it would have no chance of being included in the preferred portfolio, it would not be subject to a full-scale multiple account evaluation (T. 1101). B.C. Hydro stated that it had not developed specific guidelines for the prescreening process; instead B.C. Hydro management made the decision as to which resources should be dropped (T. 1134).

Even those potential resources which survived the prescreening process were not necessarily subject to a full multiple account evaluation. B.C. Hydro stated that it had limited its multiple account evaluation to those options with which it was proceeding, e.g. Stave Falls (T. 1138). Since, under most scenarios assessed, no major resource acquisition decisions were required, the Utility did not feel it was worthwhile to evaluate all resources against one another (T. 1138), i.e. undertake a multi-attribute trade-off analysis. This is discussed more fully below in Section 4.6.

4.5.5 Application of Resource Acquisition Policy - Transmission Resources

It is unclear the extent to which transmission resource planning has been influenced by the RAP. Although the Electricity Plan makes reference to the need to provide a reliable, safe and efficient supply of electricity that minimizes effects on the environment and is socially acceptable (Exhibit 32, Electricity Plan, p. 34/35), and B.C. Hydro's witness stated that, in principle, transmission planning was subject to the same multi-attribute evaluation as generation projects (T. 2311), the Technical Appendix contains no resource summary sheets for any of the identified transmission projects. Instead, the Electricity Plan simply identifies a number of possible transmission projects, including supply to Vancouver Island, South Interior to Lower Mainland Grid Reinforcement, and the Kelly Lake to Cheekye 500 kV project.

With respect to the last project, the Plan states that it has been under review for 15 years with B.C. Hydro consistently recognizing the strategic importance of this project. However, its forecast in-service date has been deferred several times in response to changes in load growth forecasts, economic factors and generation developments north and south of Kelly Lake (Exhibit 32, Electricity Plan, p. 38). B.C. Hydro's witness was not able to identify exactly how many studies had been done on the project but suggested that it would be in the order of a dozen (T. 2341) at a cost of approximately $6 million (T. 2344). No specific in-service date is scheduled for the project; however, B.C. Hydro indicated that it was proceeding to acquire certain critical areas of the corridor (T. 2344). To date approximately $50,000 has been spent on right-of-ways (T. 2413).

The CAC (BC) et al suggested that technological developments which allow investments in smaller generation facilities distributed throughout the system could result in B.C. Hydro having the potential to defer new investment in transmission and development. As transmission and distribution expenditures comprise a substantial part of B.C. Hydro's expected future capital expenditures, distributed generation and community energy planning could prove useful tools to achieve cost savings. The CAC (BC) et al recommended that the Commission instruct B.C. Hydro to engage in community energy planning as part of its IRP process (T. 2623).

With respect to local or distributed generation, B.C. Hydro indicated that it did not consider that the Commission's direction to WKP, to consider whether a community within its service area might be better served by distributed generation, obliged B.C. Hydro to consider the same question in the absence of a specific direction to B.C. Hydro. Nonetheless, B.C. Hydro stated that the general requirements of

IRP obligated the Utility to consider distributed generation technologies (T. 932). B.C. Hydro indicated that it planned to examine community energy planning and local regional problems in a manner consistent with the overall IRP (T. 1096) and, in addition, was in the process of preparing an IRP for non-integrated areas (T. 2301).

Commission Determinations

The evidence given at the hearing identified several areas of concern for the Commission with respect to the characterization of supply and demand resources. First, the RAP was developed without extensive formal public involvement. Although certain aspects of the policy involve items of a complex technical nature, the Commission does not believe this suggests that the development of the policy should be left solely to technical experts.

The Commission directs B.C. Hydro to ask the new IRP consultative committee to review the B.C. Hydro RAP to determine if it is consistent with IRP objectives. Technical assistance to the IRP consultative committee may be provided by in-house B.C. Hydro expertise or from external services.

Second, the Commission is concerned that B.C. Hydro has not developed a consistent set of attributes with which to evaluate resources as part of its RAP. Reliance on a wide review of the resource summary sheets (T. 2220) in order to ensure consistent evaluation of resources leaves room for error, particularly when it is realized that resource summary sheets have not been undertaken for all potential resources. For example, there is no resource summary sheet showing the quantitative impact of rate design (T. 2240).

The Commission directs B.C. Hydro to prepare a master list of attributes against which to evaluate each and every resource option. This list of attributes must be reviewed with the new IRP consultative committee.

Third, the Commission is concerned that B.C. Hydro is not using the RAP to characterize all resources and, as a result, the selection of resources to serve customers may not be optimal. B.C. Hydro has indicated that it does not apply the RAP to the dispatch of existing resources, since such application could results in the imposition of substantial additional costs upon the system. Similarly, B.C. Hydro has not applied the RAP to all committed resources stating that, in some cases, the environmental impacts are so small that resources can be evaluated solely on a project cost basis or, in others, that the government has already determined them to be in the public interest so that an evaluation under RAP is not required. Finally, B.C. Hydro has indicated that it has applied the RAP to potential resources on a selective basis only, depending on whether the resource had survived a prescreening process and whether the Utility believed it would be proceeding to develop the resource in the near term.

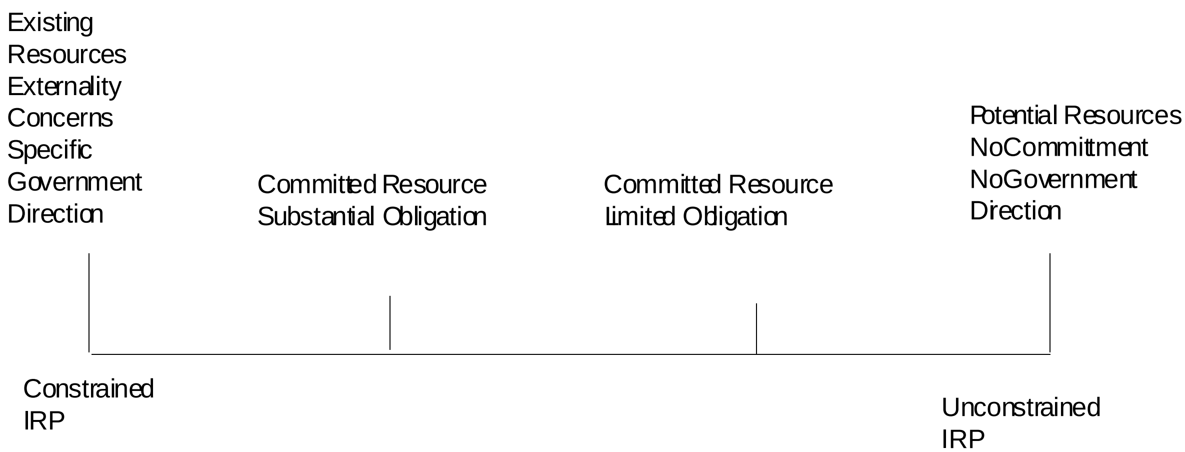
In considering this issue, the Commission finds that the RAP should be used to characterize all potential resources which survive the initial cut, so that appropriate trade-offs can be made between resources, i.e. the IRP process is, in this regard, unconstrained. This direction applies whether the resources are developed by B.C. Hydro or whether they are purchased from other suppliers.

However, in considering the extent to which the IRP process can be used to select among existing and committed resources, the Commission finds the issue more complex. The Commission believes that there is a continuum with respect to the extent to which a resource is committed. As indicated in Section 4.4, B.C. Hydro considers a resource to be committed if it is substantially complete or if the Utility anticipates no major roadblock to its approval (T. 2283). Near one end of this continuum is the case where B.C. Hydro plans to acquire the resource but only a limited commitment has taken place, so that the costs which B.C. Hydro would incur if it were to decide not to proceed with the project are small, and there is no government policy direction in favor of the project. In this case, the Commission believes that the IRP process is unconstrained. As a result, the characterization of resources according to the RAP is required and a subsequent multi-attribute trade off analysis between resources should take place. Projects which fall within this category may include certain Resource Smart projects.

Near the other end of the continuum are those resources where B.C. Hydro would incur substantial costs if it were to decide not to proceed and/or where government policy encourage the acquisition of the resource and its use under specified conditions. A consideration of these costs must be included in the characterization of the resource and any subsequent trade-off analysis. In this case, it is unlikely that the IRP process would show that the project should not be pursued and, in this sense, the IRP process may be said to be constrained. An example of this type of resource might include a resource for which construction was substantially complete, or modification to existing resources, such as the Burrard Thermal Upgrade project, which resulted from provincial government and Greater Vancouver Regional District initiatives.

Finally, at the far end of the continuum, where B.C. Hydro has existing resources, a decision to decommission the resource or to limit its use beyond that anticipated by existing government policy or licensing constraints is also likely to impose substantial costs which must be weighed against whatever benefits such change in use may bring forth. In most cases, one would expect that these costs will be so large as to negate the need for further characterization of the resource and a subsequent multi-attribute trade-off analysis. As a result, the extent to which the operation of the resource can mimic that which would have occurred if all resources were still potential is even more severely constrained. In addition, the Commission must assume that public values with respect to externalities have been incorporated into the government's decisions with respect to siting and licensing of facilities. Figure 4.5 illustrates the continuum described in this section.

Figure 4.5



This continuum with respect to resources means that the Commission can not employ a clear dichotomous approach to decisions about the selection and operation of existing resources, committed resources to which high costs of change are associated, and committed resources to which negligible costs of change are attached. Instead, the Commission must determine, sometimes on an individual resource basis, whether resource outcomes will be affected by the application of the RAP and a subsequent multi-attribute trade-off analysis. Where it is unlikely that the outcome will be changed, consideration of the resource in the IRP selection process will not be required. In making this determination, the Commission must consider government directions and other indicators of public values. This is especially true with respect to B.C. Hydro but applies to investor-owned utilities as well.

These considerations have special applicability to the Commission's deliberations with respect to the Williston Lake Reservoir, the Alcan contracts and the Columbia River Basin Downstream Benefits. With respect to Williston Lake, the Commission is sympathetic to the concerns raised by Mr. Berry. Nonetheless, the Commission recognizes that B.C. Hydro is operating within its existing water licenses and within the bounds of current government policy with respect to social costs. In addition, the Commission recognizes B.C. Hydro's concerns that the application of social costs cannot be applied to a single resource in isolation nor can it be applied to all existing resources without the likelihood of substantial rate impacts on customers.

For this reason, changes involving severe limitations on reservoir drawdowns, if they are to be made, must come through water license revisions by the provincial government. The Commission will consider for inclusion in future IRP multi-attribute trade-off processes, those projects for which there is prima-facie evidence of comprehensive net benefits or where there are net social benefits and the financial cost to the Utility customers is demonstrably small. The Commission notes that B.C. Hydro has moved to address changes in the operation of the Williston Lake reservoir through the Electric System Operations Review ("ESOR") which the Utility has filed with the provincial government.

With respect to the Alcan contracts, the Commission is aware that, at an earlier time, government made a commitment to the Kemano Completion Project; however, it has since instituted a review of the project. Although the outcome of that review is not yet known, the Commission believes that it is appropriate to undertake a constrained IRP process which will weigh whatever costs are associated with implementing the contract, including social costs, against the costs of not implementing the contract. As a result, the Commission does not agree that these contracts should be exempt from evaluation under the RAP and a subsequent multi-attribute trade-off process. For example, B.C. Hydro may have to reconsider the coordination agreement with Alcan, since the project has been delayed.

Therefore, the Commission directs B.C. Hydro to review the Alcan contracts with the consultative committee as part of its next IRP.

With respect to the DSBs, although this resource is discussed within the section of the Electricity Plan devoted to committed resources, the Commission notes that B.C. Hydro has treated this resource more as an uncertainty of which the Utility should be aware, than as a resource which the Utility may choose to acquire. This reflects the fact that B.C. Hydro's access to this resource will be determined by government policy rather than by its own decision-making authority. The Commission believes that this is the appropriate manner in which to treat this resource within the context of the IRP.

The Commission has also identified a number of other specific concerns related to the characterization of resources. First, the Commission is not convinced that the use of an emission adder is necessarily the most appropriate means of dealing with greenhouse gas emissions or with the risk of a carbon tax.

The Commission directs B.C. Hydro to review its policy with respect to the method of evaluating greenhouse gases with the IRP consultative committee to determine if this is the best method of incorporating greenhouse gases into the decision making process. The Commission notes that the use of the emission adder approach is not necessarily the most appropriate means of dealing with greenhouse gas emissions, given the possibility that the future may include regulated limits and/or a carbon tax. Indeed, many existing and proposed carbon taxes actually exceed $15 per tonne of

CO_2. Consequently, the Greenhouse Gas strategy should be linked to the IRP, e.g. through scenario and other forms of risk analysis.

In an attempt to secure province-wide consistency, the Commission intends to address this issue further in the coming year in an initiative which will include other utilities under its jurisdiction as well as other interested parties. Specific information regarding this initiative will be forthcoming at a later date.

Second, the Commission does not believe the Utility has adequately addressed the risks attached to various resource options. In particular, the Commission notes the use of single point estimates of costs and or benefits rather than a range.

The Commission directs B.C. Hydro to undertake a more explicit treatment of uncertainty with respect to the cost and benefits, both monetary and non-monetary, of resource options.

Finally, the Commission is concerned that there is an insufficient link between the characterization of generation resources on the one hand and transmission and distribution resources on the other. The Commission wishes to see a more explicit coordination of scenarios for generation with transmission and distribution planning.

In undertaking these scenarios, B.C. Hydro is directed to consider the extent to which market forces are encouraging increased distributed generation and the consequential effect such increases may have on its transmission and distribution investment, i.e. the potential for stranded investment.

Similarly, the Commission directs B.C. Hydro to continue its assessment of the potential impacts of community energy planning. Among other issues, community energy planning suggests that urban form and fundamental community decisions about energy distribution infrastructures are critical to providing low cost and sustainable energy futures. Such an assessment of the potential impacts of community energy planning should include increased analysis, constructing plausible supply cost curves for categories of resources (e.g. fuel cells) and urban design measures to permit an adequate comparison of small scale options with larger scale options. A comparison of one increment of a resource to another may not be acceptable, given both differences in economies of scale and in the scale of non-monetary impacts.

4.6 Development, Evaluation and Selection of Integrated Resource Portfolios

4.6.1 Selection of the Preferred Portfolio

BCUC Guideline #5 calls for the development of several plausible resource portfolios to meet each of the gross demand forecasts. BCUC Guideline #6 calls for each of the alternative resource portfolios to be compared on an attribute by attribute basis, as defined by the objectives of the IRP. This process, which must involve the public, is expected to lead to the selection of a set of resource portfolios, each portfolio matching one of the gross demand forecasts. This set of resource portfolios is the Utility's IRP.

B.C. Hydro's Electricity Plan does not present alternative resource portfolios for each level of forecast demand but instead presents a single preferred portfolio for all levels of demand. The Utility indicated that it will address the risk of supply and demand imbalance through adjustments to project schedules, power purchase and sales opportunities, thermal generation levels and storage levels in multi-year reservoirs (Exhibit 32, Electricity Plan, p. 43). Each of these has vastly different environmental and social implications.

Initially, the preferred portfolio consisted of those resources which were not eliminated through the prescreening process (T. 1642). B.C. Hydro then input the short-listed resources into its resource planning model to evaluate sequences (T. 1140). The Utility stated that the resource planning model considered only monetized inputs; however non-monetized factors were considered and incorporated in the selection of the preferred portfolio based on the subjective judgment of B.C. Hydro managers (T. 1139, 1144). Although rating and weighting schemes had been applied in previous plans to assess potential resources, there was no explicit decision-making technique used to establish the portfolio described in the 1994 Plan (T. 1144). The Utility indicated that it did not specifically rank resources against one another, as it was not recommending proceeding with resource acquisitions (T. 1138). The lack of an explicit decision-making technique, such as multi-attribute trade-off analysis, to rank resources is consistent with the Utility's RAP which states that, due to the many disparate trade-offs required, no specific decision analysis technique is recommended (Exhibit 32, RAP, p. 8).

The Energy Coalition argued that the resource selection process should not be left in the hands of B.C. Hydro's managers but should be the result of a multi-attribute trade-off analysis ("MATA") which involved the public. In its Argument, the Energy Counsel stated that:

> "One of the highest goals of public participation processes should be to satisfy parties affected by a decision that their interests have been fairly represented in the process of making the decision. Identifying attributes and creating accounts that incorporate these interests (e.g. an Environmental account) is a necessary first step. However, there will also be a subsequent step in the decision-making process in which the competing interests represented by the various accounts are combined, compared and resolved. It is necessary that this step also be amenable to public scrutiny.

> Despite its known mathematical flaws, the IRP recently submitted by West Kootenay Power provides a good example of how trade-off analysis can be used to satisfy the requirements of public participation, with the exception that more specific information and more time would have created a better product." (T. 2666)

B.C. Hydro also took the position that the public could be involved in making these trade-offs (T. 1145).

B.C. Hydro identified its preferred resource portfolio as consisting of Power Smart, Resource Smart, Lower Columbia Development, combined cycle gas turbines, new self-generation projects and other cost-effective measures (T. 1142, Exhibit 32, Electricity Plan, p. 34/35). The Utility indicated that the preferred portfolio was basically unchanged from the 1990 Electricity Plan (T. 1142).

4.6.2 Resource Acquisition Strategy

Although B.C. Hydro did not specify its decision-making technique in establishing its preferred portfolio, the Electricity Plan does specify certain guiding criteria with respect to the timing of the acquisition of new resources, i.e. an acquisition strategy. The Plan states that resources will be acquired on the basis of need to ensure that future electricity requirements are reliably met. In addition, resources will be acquired in advance of reliability requirements if there is an opportunity to reduce the expected social cost of meeting future requirements (Exhibit 32, Electricity Plan, p. 8). In this regard, B.C. Hydro specifically identified the acquisition of lost opportunity resources and the funding of certain existing Power Smart programs that are not cost-effective themselves but which are necessary to maintain the ongoing viability of the larger Power Smart resource (Exhibit 32, RAP, p. 12/13). Further, the Electricity Plan states that private sector and other resources that represent economic opportunities for B.C. Hydro (i.e. a cost of about 2.5¢/kW.h) will be considered. Slightly higher cost resources may also be considered if they are cost-effective alternatives for meeting local or regional system reinforcement requirements, or provide sufficient social and environmental benefits (Exhibit 32, Electricity Plan, p. 8).

B.C. Hydro stated that the 2.5¢/kW.h, which constitutes a standing offer at which to purchase electricity, was set to ensure that the benefits from purchase would outweigh any risk of oversupply (Exhibit 3, BCUC4R, 28-1). Although the Utility was unable to provide a specific derivation of the number, they indicated that it reflected the cost of new supply over the next couple of years and an examination of potential projects which might become available (T. 1480). More specifically, B.C. Hydro indicated that the 2.5¢ was below its short-run cost of new electricity supply and would generally be less than the price at which the Utility could expect to resell the energy in the non-firm export market (T. 2272).

During the course of the hearing, there was significant discussion as to whether the decision to acquire private sector resources was being made on the same basis used for B.C. Hydro controlled resources, particularly Power Smart. B.C. Hydro indicated that, when considering the cost of resources, other than in the case where acquisition is being considered in advance of need, potential lost revenues to B.C. Hydro are considered a transfer payment and so are not included in the computation of the total cost to society (T. 1383). In contrast, when resources are being considered in advance of need, the inclusion of lost revenues is appropriate, since the advanced acquisition of the resource is being justified on the basis of an economic opportunity to B.C. Hydro, i.e. a reduced revenue requirement to B.C. Hydro's other customers (T. 1482). In discussing Self-Generation Load Displacement ("SGLD") projects, defined by B.C. Hydro as private sector generation of electricity to displace all or part of the load requirements of a Utility customer or potential new Utility customer (Exhibit 32, RAP, p. 13), B.C. Hydro indicated that it would consider supporting SGLD if sufficient benefits to all customers could be demonstrated (Exhibit 32, RAP, p. 13). However, the Utility stated that it was not prepared to pay a customer with a self-generation opportunity to reduce load in the same manner as the Utility might pay the customer to reduce load through Power Smart. Although the Utility appeared to recognize that both acquisitions imposed similar costs on B.C. Hydro, i.e. the lost revenue, B.C. Hydro appeared to suggest that Power Smart must be acquired ahead of need due to the length of time necessary to build the resource and, therefore, should be treated differently from SGLD (T. 1482). The Industrial Customers did not agree, arguing that cogeneration projects, which result in reduced customer load, should be evaluated and financed under the Power Smart option rather than as an IPP option (T. 2584).

The Industrial Customers argued that additional hurdles faced by IPPs included a preference on the part of B.C. Hydro to see IPPs break their bids into specific elements rather than evaluate projects based on the bid price in total and the application of B.C. Hydro's cost of capital to IPP projects even though IPPs are subject to different costs of capital and different risks. The Industrial Customers also argued that B.C. Hydro's approach did not allow the Utility to judge the choice between an IPP resource and an internal B.C. Hydro project in a manner that is fair or conducive to maximum efficiency (T. 2581).

As a result, the Industrial Customers suggested that B.C. Hydro implement the following changes:

1. B.C. Hydro should review IPP bids in the same manner and through the same process as B.C. Hydro internal alternatives for inclusion in various portfolios under the IRP.

2. B.C. Hydro should not require an IPP to break its bids into its various elements as this effectively requires the IPP to provide what might fairly and properly be considered confidential information. Instead, an IPP should present a contract price and evidence of ability to perform.

3. B.C. Hydro should not simply attribute B.C. Hydro's cost of capital to the IPP but should recognize that IPPs have a different cost of capital than B.C. Hydro and assume different risks than B.C. Hydro which are reflected in its cost of capital (T. 2581).

Commission Determinations

B.C. Hydro has applied a multiple account evaluation process to many of its potential resource acquisitions but has not used a formal decision-making process, such as multi-attribute trade-off analysis, to determine its preferred resource portfolio. The Commission does not accept the argument that this was unnecessary, since no resource acquisition decisions are required in the immediate term. Similarly, the Commission does not accept the argument that the many disparate trade-offs required mean that no specific decision analysis technique can be recommended. Instead, the Commission believes that various decision analysis techniques can be used to provide information to decision-makers while still using multi-attribute trade-off analysis to develop and select amongst resource portfolios.

To date, B.C. Hydro has used multiple account evaluation simply as a means of structuring information for use in an apparently unstructured decision-making process. While this limited use of multiple account evaluation may prove useful to decision-makers, it does not allow for public scrutiny of the decision. As a result, the decision-making process continues to be opaque rather than transparent. The Commission believes an explicit decision-making process is necessary if the public is to be assured that all interests have been fairly represented and fairly considered.

The Commission finds that B.C. Hydro has not complied with the IRP Guidelines which require an explicit decision-making process which includes public involvement. The Commission directs B.C. Hydro to institute with the new IRP consultative committee a multi-attribute trade-off analysis for the purposes of portfolio development and selection. The MATA process should be conducted along the lines of that conducted by West Kootenay Power as part of the development of its IRP except that such necessary changes as outlined in the Commission's Decision, dated June 17, 1994, shall be made.

In making this direction, the Commission does not relieve B.C. Hydro's management or Board of Directors from their over-riding responsibility for appropriate resource selection. Instead, the Commission wishes to indicate its agreement with the position of the Energy Coalition that:

> "There is no contradiction between a stakeholder committee making recommendations on a complete range of IRP issues, and the utility then taking these recommendations into account in the final preparation of its IRP and offering an explanation in those instances where the stakeholder recommendations are not followed. The value of the collaborative

> in this sense is not that the "people" get to decide, but that the utility is made accountable for its decisions" (T. 2673).

With respect to IPP projects, the Commission finds that they are not being considered for acquisition in a manner consistent with that used for B.C. Hydro in-house resources.

The Commission directs B.C. Hydro to apply the same criteria for acquisition of IPP projects as it does to B.C. Hydro in-house resources. A consistent set of decision criteria will overcome allegations that any one resource is being unfairly limited in its potential to meet the future resource needs of the Utility. Further, the Commission is concerned that B.C. Hydro has insufficient information about potential IPPs to adequately assess what resources are available. The Commission directs B.C. Hydro to issue a Request for Proposals ("RFP") for IPP capacity and energy, no later than January 31, 1995. The responses to the RFP are to be reviewed with the new IRP consultative committee in a manner which preserves necessary confidentiality for the respondents. Each RFP response shall also be provided to the Commission on a confidential basis which will respect the privacy of sensitive information consistent with the requirements of the Freedom of Information and Protection of Privacy Act.

4.7 Public Input

BCUC Guideline #8 calls for the involvement of the public throughout the IRP process and identifies a number of methods which utilities may use to achieve this requirement. These include stakeholder collaboratives, information meetings, workshops, and issue papers seeking public response. Utilities are encouraged to use those forms which best meet the needs of their IRP.

In its Decision dated December 7, 1993, the Commission stated the following with respect to public involvement in B.C. Hydro's planning process:

> "The Commission ... expects B.C. Hydro to demonstrate that it effectively involves the public early in the resource planning process. One way to do this would be to expand the terms of reference of the Conservation Potential Review stakeholder collaborative to full Integrated Resource Planning." (Executive Summary, pp. 2/3)

> and

> "In addition, the Commission suggests that B.C. Hydro expand the mandate of the DSM collaborative to embrace a broader IRP focus. With the wider mandate, the collaborative could consider social costing and how it should be used within the IRP process. At present, the Commission does not find the link between the Utility's social costing initiatives and its IRP initiatives to be clear. Alternatively, B.C. Hydro may wish to

> institute some other process to achieve the goal of full stakeholder participation in IRP. The Commission leaves the exact mechanism to the discretion of the Utility but expects to see this public consultation objective achieved, with a report to the Commission by June 30, 1994." (Decision p. 42)

By way of a letter dated June 30, 1994, B.C. Hydro informed the Commission that the Utility had not met all the requirements of the Commission's direction with respect to the involvement of the public early in the resource planning process, but had made a number of significant steps. These included using the information and experience already gained at numerous planning and consultation activities related to components of IRP as well as the identification of a number of new areas which required public input. B.C. Hydro indicated that it was working on a public participation program scoping document which it intended to file by August 31, 1994 (Exhibit 34).

On August 31, 1994, B.C. Hydro filed the Integrated Resource Planning - Public Participation Program (IRP4) Scoping Document. B.C. Hydro stated that the goal of IRP4 was to develop a comprehensive approach to involving the public in the Utility's integrated resource planning process (Exhibit 32, IRP4, p. 4). A six phase approach to achieving this goal was described. These included: (1) identification of all existing and planned B.C. Hydro public consultation/communication programs and a determination of their relationship to IRP and other planning activities; (2) identification of potential participants; (3) determination of the planning issues in which the public is interested; (4) determination of the most appropriate way to incorporate public input into the Utility's planning, and (5) a finalization of the program. These five phases were expected to take until March 1995 to accomplish. Phase 6, implementation of the program, was not scheduled to begin until April 1995 with significant results not expected before March 1996. B.C. Hydro indicated that this was an effective and prudent approach to public participation in IRP, particularly given the significant input the Utility already received through various other consultation programs (T. 2549).

There was considerable discussion at the hearing concerning the extent to which the Utility had achieved appropriate public involvement. B.C. Hydro identified 44 separate public processes or consultation programs on which it had already embarked (T. 2374, Exhibit 19). Most of these programs appeared to be focused on a particular project, e.g. Burrard Thermal Upgrade, or focused on the concerns of a particular region, e.g. Lower Mainland Electricity Choices, rather than on the B.C. Hydro system as a whole. Although B.C. Hydro acknowledged that certain issues, (e.g. the treatment of greenhouse gases, the priority of large projects), need to be discussed at a system rather than regional level, the Utility indicated that the advent of distributed generation would require a greater focus on regional level issues. As a result, the Utility recognized that there was the potential for conflict between community based energy planning and system planning (T. 1425). B.C. Hydro stated that it wished to build upon the regional processes already in place and complement them with additional programs focused on other regions even though it recognized that there might be conflicts between regions and some process of arbitrating between the results of various regional public processes might be necessary. (T. 1098).

As well as being regional in approach, many of the current public consultation programs appeared to be programs that asked for response to projects which had already been chosen by the Utility. This was characterized by the Energy Coalition as a "decide, announce, defend approach" to public participation (T. 1099). B.C. Hydro indicated that future public participation programs would try to involve the public sooner than had been the case in the past (T. 1100). Nonetheless, B.C. Hydro admitted that, in the year since the past hearing, it had not developed a specific program targeted at allowing the public to participate in determining what the source of B.C. Hydro's future supply mix should be (T. 862).

The Energy Coalition indicated that B.C. Hydro's past approach to public participation:

> "made it clear that (B.C. Hydro) sees no difference between conducting a single IRP process that involves one group of stakeholders in the comprehensive range of IRP issues, and aggregating the results of several processes that individually deal with one small part of IRP. This might make sense if one accepts the "information gathering" theory of public involvement. The result is that the only people who understand the full range of IRP issues - "the big picture" - are the planners and senior managers at B.C. Hydro. Clearly, this is not acceptable and not consistent with Guideline 8." (T. 2675)

The Energy Coalition asked that the Commission clarify in its Decision that information gathering does not satisfy the requirement for public participation.

B.C. Hydro provided information showing that it planned to spend approximately $4.7 million over the life of the current public involvement programs (Exhibit 75). In addition, the Utility indicated that $400,000 had been budgeted for the IRP4 program, the bulk of which, approximately $300,000, would be related to the final implementation phase (T. 2376, 2384). In response to this evidence, the Industrial Customers indicated that they were concerned about the large number of public consultation programs already taking place and the number of additional processes likely to commence in the future (T. 2590). In addition, the Industrial Customers expressed concern as to whether the programs would be effective.

> "There can be no question that this broad scale, low level consultative approach is expensive and inefficient. Furthermore, there is a real danger that unless these consultations take place within a focused overall framework, such as the Integrated Resource Plan, that they will become increasingly inaccessible to intervenors." (T. 2565)

There was also significant discussion during the hearing as to what form future public consultation should take. B.C. Hydro indicated that it wished to begin the IRP4 consultation process by discussing with the public opportunities for public involvement to determine areas of interest. Once this was known, the Utility would attempt to develop a consultation program which would address those issues (T. 1094).

B.C. Hydro stated that it had discussed the idea of a collaborative and was comfortable with it for certain elements of the IRP, e.g. resource acquisition, but was concerned about instituting a collaborative process for issues where B.C. Hydro lacks the authority to make decisions. However, before imposing a collaborative process, the Utility indicated that it wanted to determine the process the public would like to follow and the issues they would like to examine (T. 1684). Although B.C. Hydro agreed that public policy choices should reflect public opinion, B.C. Hydro expressed concern about consulting on decisions which they do not ultimately make (T. 893).

The Energy Coalition submitted that:

> "This statement implies that B.C. Hydro believes that collaborative necessarily grant final decision making authority to the stakeholder group. This is not true. In the administrative context the collaborative makes a recommendation to the final decision maker. Indeed, it would be contrary to law for an administrative tribunal to delegate its final decision making authority." (T. 2672)

There was concern raised at the hearing as to when the results of the IRP4 would be ready for inclusion in the Plan. One Intervenor, Mr. Ward, stated that the proposal suggested that meaningful public consultation would not take place until April, 1995 and that this acted to guarantee that the collection of planning documents for that year will also have avoided the scrutiny of meaningful public involvement. As a result, he indicated that the 1995 documents will no more constitute an IRP than this year's documents (T. 2779). Similarly, the CAC (BC) et al indicated that the proposed plan would result in the public consultation process proceeding at a "glacial pace" (T. 2616). B.C. Hydro indicated that the process was on-going so that information would be incorporated as it became available. B.C. Hydro rejected the notion that the schedule meant that the 1995 Electricity Plan would not have extensive public input, stating that there were a substantial number of current public consultation programs which influenced it. B.C. Hydro indicated that the IRP4 was intended to fill in the gaps around the Electricity Plan (T. 1445).

Several Intervenors questioned whether B.C. Hydro had complied with the Commission's directions with respect to public participation, particularly that B.C. Hydro achieve the goal of full stakeholder participation in IRP with a report to the Commission by June 30, 1994. B.C. Hydro stated that the Executive Summary attached to the December 7, 1993 Decision indicated that the Utility was to demonstrate that it was involving the public at an early stage in the process. B.C. Hydro interpreted this to mean that it could review its existing programs to determine if they were adequate and, if not, recommend the development of a program to make them adequate (T. 1633). By submitting a letter on June 30, 1994 which outlined B.C. Hydro's current public participation programs and plans for future public participation, the Utility indicated that it believed it had complied with the directive (T. 882). Nonetheless, B.C. Hydro agreed that an alternative interpretation of the Decision, namely that B.C. Hydro was to institute a new public participation process aimed at IRP and with a completion date of June 30, was possible. B.C. Hydro agreed that where the intent of the regulator was unclear, the Utility had a responsibility to obtain clarification (T. 2372).

In response to questions as to why it took nine months to produce the IRP4 scoping document, the substantive portion of which is approximately 15 pages, B.C. Hydro indicated that it had been evaluating the existing processes during that period to see how the various processes were coordinated internally and to see how these fit into the Utility's broader resource planning effort . B.C. Hydro indicated that the plan for this coordination has not yet been formalized (T. 1427).

In response to B.C. Hydro's assertion that it had complied with the Commission's direction with regard to public participation, the CAC (BC) et al argued that the Commission must determine whether B.C. Hydro's interpretation was reasonable.

> "In judging whether it was reasonable for B.C. Hydro to interpret the Commission's 1993 decision as not requiring full public involvement by June 30, 1994 and whether B.C. Hydro did, in fact, interpret it that way, there are two alternatives. The first is to accept that the only possible interpretation of the 1993 decision was that B.C. Hydro was to achieve full public involvement and then report to the Commission before June 30, 1994 on how it had done that. If this is accepted, then it follows that B.C. Hydro either unreasonably failed to understand and act on the decision or that it deliberately chose to ignore the Commission's decision.
>
> The alternative is to conclude that there really was ambiguity in the Commission's decision. That is to conclude that although the Commission wanted a report on public involvement by June 30, 1994, it did not necessarily intend that there would have been any progress upon which to report and it had not set any deadline whatsoever for actually achieving public involvement, i.e.. that as long as the report was submitted by June 30, 1994, it would have been satisfactory if public involvement did not take place for another year, or five years, or ten years or more. This also requires concluding that the supposed ambiguity did not oblige B.C. Hydro to take any steps to resolve the ambiguity, such as telephoning the Commission. A further requirement of accepting this interpretation is to conclude that B.C. Hydro managed to remain completely unaware of what other utilities in British Columbia were being required to do at this time and were, in fact doing. In addition it requires accepting that B.C. Hydro have forgotten the Commission's requirement that all utilities submit an IRP with public involvement by the end of 1993. In sum, this alternative requires accepting a lot that seems unlikely." (T. 2614/15)

The CAC (BC) et al asked the Commission to direct B.C. Hydro: (1) to accelerate the completion of the six phases set out in IRP4 and to incorporate the results of the public involvement in the 1995 Electricity Plan; (2) to report in writing on a monthly basis to the Commission on its progress in achieving full public involvement; and (3) to ensure that the Commission's concerns about B.C. Hydro's failure to comply with its directions on public involvement with respect to IRP are brought to the attention of B.C. Hydro's Board of Directors (T. 2619).

Commission Determinations

B.C. Hydro has not followed the spirit of the Commission's Guidelines with respect to public involvement, has not followed the specific directions given to it in the last Decision with respect to public involvement, and has not made the obvious responsible effort to seek clarification from the Commission as to what was required by a direction which B.C. Hydro alone suggests was ambiguous. Although the Utility has put into place a number of processes which deal with the public, it appears that the majority of these processes are more in the nature of education programs which provide information to the public but do not involve the public in the decision-making.

The Commission finds such an approach unacceptable for two reasons. First, decisions concerning resource acquisition require not only the consideration of the direct costs and benefits attached to a particular project but also the indirect, and frequently intangible, costs and benefits. Determination of the appropriate trade-offs between resources requires that the values the public attaches to these costs and benefits must be determined and factored into the decision in an explicit and transparent way. The Commission has made it clear that such values are best determined through the direct participation of representative interest groups.

Exclusive reliance on the B.C. Hydro staff, managers and Board of Directors for resource selection is also unacceptable for another reason. A closed, in-house process has the appearance of, and real potential for, bias in decision making that favors the interests of the bureaucracy within the Utility. Indeed, evidence at the hearing suggested the existence of a double standard with respect to the treatment of B.C. Hydro resources, such as Power Smart and Resource Smart, and the treatment of non-B.C. Hydro resources, such as self-generation and IPP projects. It appeared that, in some unjustified circumstances non-B.C. Hydro resources are required to beat short-run marginal cost, while the B.C. Hydro resources need only beat long-run marginal cost (T. 2272).

This failure to understand or, if understood, failure to comply with, the Commission's Guidelines and directives with respect to public participation forces the Commission to issue new directions with respect to this issue that are unprecedented in their detail. The Commission regrets that such action is necessary since it is wary about entering areas that have traditionally been the prerogative of management; however, B.C. Hydro's failure to respond to the Commission's December 7, 1993 directions leaves it no choice.

The Commission directs B.C. Hydro to cease work on the IRP4 initiative and to undertake a public involvement process as set out in this Decision. B.C. Hydro is directed to begin immediately to constitute an IRP consultative committee. As a first step towards establishing the committee, the Commission directs B.C. Hydro to ask the organizations already represented on the DSM collaborative if they wish to be members of the new consultative committee. In addition, B.C. Hydro should invite IPP representation. The Utility may also augment the committee by adding representation from one or two other groups, if it so desires. The main membership of the consultative committee is to be established no later than December 15, 1994.

The Commission is aware that different parties may attach alternative meanings to terms such as "consultative committee" or "collaborative" and have contrary understandings as to what these terms imply. The Commission notes that the Energy Coalition indicated that the use of the term collaborative does not imply that B.C. Hydro has or must delegate its ultimate decision-making responsibility to the group (T. 2672). Nonetheless, the Commission is aware that the Conservation Potential Review Collaborative was delegated decision-making authority so that the use of this term may imply a continuation of that practice to some parties. As a result, the Commission has employed the term "consultative committee", the term used by WKP, throughout this Decision. However, depending on the definition of collaborative which it understands, B.C. Hydro may prefer to call the group a collaborative, or a Stakeholder Group, which is the term used by BC Gas. Whatever name is chosen by B.C. Hydro, final decision-making power with respect to the IRP put forward to the Commission will remain with the Utility.

In general terms, the duties of the consultative committee should include, but not be limited to, a comparison, on an equal footing, of all resources under consideration by B.C. Hydro. In the near term, the consultative committee should also be asked to undertake an analysis of the risks and benefits associated with B.C. Hydro's treatment of DSB's as well as purchases from Alcan. B.C. Hydro is directed to conduct the IRP consultations within the context of emerging trends in electricity markets and changing regulatory norms. If B.C. Hydro wants to conduct a separate consultation on these issues, it is the shareholders and not the customers who should pay for the separate process.

As the Utility indicated during the course of the hearing that it did not feel obligated to take into account directives issued to other utilities when undertaking its IRP activities, the Commission repeats, with slight changes to enhance their applicability to B.C. Hydro, the principles it gave to WKP and BC Gas Utility Limited with respect to public participation. At the same time, the Commission states, that in this instance, and in all future instances, it rejects the validity of such an excuse. Utility management must keep abreast of trends in Commission decisions and notices, especially when they have obvious applicability to other utilities.

A consultative committee should be established with independent control over its process. Participating members must be clearly aware that the outcome of the process cannot be binding on the Utility management. Ultimately, the Utility management and then the Commission have decision-making responsibility for determining the prudency of the Utility's IRP and the Action Plan contained therein. Neither management nor the Commission can avoid their responsibilities via a consultative process.

The consultative committee should try for consensus. Where consensus cannot be realized, members may write dissenting opinions.

An independent facilitator should be retained by the consultative committee.

The consultative committee should have explicit representation from environmental and other key interests. The individuals providing such representation need not reside in the Utility service area, although this may be preferred.

The consultative committee must be given sufficient time, recognizing the iterative process involved in conducting in-depth trade-off analysis of the major packages of resource options. However, public involvement processes must conform to Commission deadlines.

The Commission also makes the following specific directions with respect to the workings of the consultative committee.

First, B.C. Hydro is directed to provide the members of the consultative committee with written information that clearly articulates B.C. Hydro's IRP planning process no later than January 15, 1995. This material should cover the steps required to produce the IRP and identify who within B.C. Hydro is responsible for each of these items. The material should also specify how IRP fits into the broader strategic and corporate planning activities of the Utility. The Commission believes that this material will be helpful not only to the members of the consultative committee but will also be of assistance to others interested in B.C. Hydro's planning. The Commission notes

that the need for this material is evident from the length of time spent during the 1994 hearing trying to elicit this information.

Second, B.C. Hydro is directed to review its IRP Objectives with the consultative committee. An explicit and consistent set of objectives must be included in the next IRP. Further, these objectives should be clearly linked to the subsequent analyses in the Plan. The final set of objectives may ultimately be a combination of stakeholder, staff, management and Board of Directors' views.

Third, B.C. Hydro is directed to review with the consultative committee its load forecasting methodology, including the treatment of DSM (natural change and Power Smart). The consultative committee should be consulted on scenario development for load forecasts. These scenarios should be subsequently linked to the risk analysis contained in the IRP.

Fourth, B.C. Hydro is directed to review with the IRP consultative committee existing Power Smart Programs in light of the Conservation Collaborative Phase II results and make recommendations regarding potential future DSM resource options. All DSM options will then be evaluated in the context of other supply-side options as part of the IRP.

Fifth, B.C. Hydro is directed to review the existing Resource Inventory with the consultative committee with a view to improving upon the collection and presentation of information for resource evaluation.

Sixth, B.C. Hydro is directed to review the RAP with the consultative committee. If the committee finds it helpful, B.C. Hydro may retain additional assistance from experts to work with the consultative committee on this review. As noted previously in this Decision, B.C. Hydro is directed to prepare a master list of attributes against which to evaluate resource options and to review this list with the committee. As well, B.C. Hydro is directed to review its policy with respect to evaluating greenhouse gases with the IRP consultative committee to determine the best method of incorporating greenhouse gas concerns into the decision making. Finally, the Commission directs B.C. Hydro to institute with the IRP consultative committee a multi-attribute trade-off analysis for the purposes of portfolio development and selection. The MATA process should be conducted along the lines of that conducted by West Kootenay Power as part of the development of its IRP, except that such necessary changes, as outlined in the Commission's Decision, dated June 17, 1994, should be made.

Seventh, B.C. Hydro is directed to allow the IRP consultative committee to act as a forum for focused stakeholder input to the Utility. However, this does not obviate the need for wider public

consultation and information programs. Therefore, the Commission directs B.C. Hydro to develop and implement an overall public involvement strategy which will achieve the integration of existing programs with the IRP consultative committee by June 30, 1995.

The Commission does not believe that the implementation of this direction will require a larger budget for effective public involvement in B.C. Hydro. Indeed, evidence at the hearing suggested that there may be significant opportunities to reduce current expenditures and re-allocate existing public consultation budgets. As the Commission is concerned about the cost-effectiveness of B.C. Hydro's public involvement activities, the Commission suggests that the Utility undertake a quick internal review of the effectiveness of its various public consultation programs to find synergies and other cost effective reductions that would allow it to reduce the total current public consultation budgets in the order of 10 percent. Cost savings so achieved are to be used to fund the IRP consultative committee. This Commission expects to see immediately a more explicit link between the results of existing and future public involvement activities and Utility resource planning decisions.

In making these determinations, the Commission does not reject B.C. Hydro's arguments about the need for regionally focused public participation programs. Indeed, given the size of B.C. Hydro's service area, and the regionalization of other provincial planning processes, the Commission recognizes that an increased emphasis on regional utility system planning may be the best way of ensuring the integration of small-scale, regional resources, such as distributed generation and targeted DSM, particularly in the context of transmission and distribution planning. However, regional utility system planning does not nullify the need for system-wide checks and balances to ensure consistency is maintained, to support provincial objectives, and to address interregional trade-offs. Further, the Commission anticipates that regional utility system planning will require a transition period before it becomes fully effective. In the interim, the Commission affirms the need to conduct system-level IRP to facilitate future prudency reviews. Therefore, the Commission concludes that regional public participation programs are insufficient by themselves and must be undertaken within a system-wide framework.

4.8 Regulatory Input, Government Policy Input, and Regulatory Review

BCUC Guidelines #9, #10 and #11 deal with the relationship between a utility's IRP and the regulator and government. Guideline #9 indicates that BCUC staff should be given the opportunity to review and comment during the various phases of preparation of the IRP. Guideline #10 states that the IRP should address existing government policy as well as emerging policy issues which may pose risks to the utility. Guideline #11 indicates that the Commission will review the IRP.

There was considerable discussion at the hearing concerning whether the documents filed by B.C. Hydro did, in fact, constitute an IRP. Although the Utility accepted that there were areas where improvement was possible, particularly with respect to a need to improve the readability and clarity of all documentation related to the Electricity Plan (T. 2550), the Utility maintained that its filings fulfilled the majority if not all of the Commission's Guidelines. In support of this position, B.C. Hydro noted that the consultant hired by Commission staff to review the 1992 Electricity Plan had indicated that it met generally accepted utility standards for IRP (T. 1419). In addition, B.C. Hydro stated that it had produced several new documents, including the RAP and a Technical Appendix, to address Commission concerns identified in the previous hearing (T. 2550).

The view that the filings produced by B.C. Hydro as its IRP were sufficient was disputed by several intervenors. The Industrial Customers identified several problems with the Utility's IRP and noted that:

> "B.C. Hydro has yet to address in an understandable manner the integration of supply side, Resource Smart, (DSM) and rate design options. It is our submission, based on a review of the material filed in this hearing and the Integrated Resource Planning documents, that all of the resources proceed through different tracks with different criteria and methods of evaluation. There is
>
> i) no clear ranking of supply options;
>
> ii) no clear portfolio alternatives;
>
> iii) no visible and identifiable risk analysis;
>
> iv) no synchronization or comparability of data received pursuant to a RFP from IPPs with that obtained from internal resources." (T. 2591)

This theme was also picked up by the Energy Coalition which stated that the documents filed by B.C. Hydro did not meet the threshold requirements of an IRP (T. 2642). In support of this position, the Energy Coalition stated that:

> "The Resource Acquisition Policy and Technical Appendix are a cosmetic improvement to the most serious problem identified by Barakat and Chamberlin in its review of the 1992 Electricity Plan: the lack of transparency of the resource planning process and the barrier it creates for public accountability. Even after two weeks of hearing, the trade-off process that went into these documents is still as mysterious as the Sphinx." (T. 2646)

In addition, the Energy Coalition stated that there had been no clear articulation of how non-monetized impacts were considered during the evaluation of resources (T. 2647).

In light of these deficiencies, as well as the deficiencies identified with respect to public participation, the Energy Coalition stated that for the Commission to accept the B.C. Hydro 1994 Electricity Plan as an IRP:

> "... would be offensive to the other utilities who have attempted in good faith to meet the requirements of the IRP Guidelines. It would also discourage other utilities from taking the IRP Guidelines seriously in the future." (T. 2651)

Similarly, Mr. Ward indicated that what B.C. Hydro had presented:

> "is not an IRP, but merely a collection of the same old planning documents produced year- after-year for public information purposes." (T. 2776)

Several parties also suggested that B.C. Hydro's actions since the issuance of the last Decision suggested that B.C. Hydro did not take seriously the Commission's direction to make those changes which were necessary to convert the Electricity Plan into a full Integrated Resource Plan, including full public participation, and to file such a plan by June 30, 1994. For example, the Utility indicated that no specific directive had ever been issued by B.C. Hydro senior management to implement the Commission's Guidelines and that there was no written timetable for achieving full compliance with those Guidelines (T. 1430). Similarly, the Utility indicated that no specific budget for IRP had been created (T. 988).

In addition, the evidence given by the Utility indicated that responsibility for the IRP was fragmented. B.C. Hydro stated that responsibility for coordinating IRP is one of the responsibilities of the Resource Planning group (T. 946, 1430), a section of Corporate and Strategic Planning (T. 975), but that input is received from other groups within the Utility such as Power Smart, Corporate and Aboriginal Affairs, Customer Services, and Finance and Environmental Affairs (T. 945). Not all of these groups report to the same Vice-President (T. 954) and no formal procedure was identified for coordinating these activities.

On the basis of this evidence, the Industrial Customers submitted that:

> "It would appear that there is no one at B.C. Hydro with a mandate to develop an Integrated Resource Plan of the sort envisaged by the Commission. In our submission, it is unlikely that such a plan will be forthcoming due to the departmentalized nature of B.C. Hydro until somebody is given a clear mandate and responsibility to develop one, with the necessary authority to force the cooperation and integration approaches over the various affected departments and groups." (T. 2594).

B.C. Hydro disputed the idea that it had not taken IRP seriously and identified a number of changes undertaken over the last few years which were of assistance to IRP work being undertaken at the Utility. These included the bringing together of Resource Planning and System Planning, the areas responsible for IRP and transmission planning respectively, into the Corporate and Strategic Planning Unit; the further incorporation of areas responsible for rate design and unbundling of services into Corporate and Strategic Planning unit; and the establishment of a number of ad hoc committees and working groups to focus on IRP related problems. These groups and committees were referred to as the IRP team (T. 972). B.C. Hydro indicated that no minutes were kept of IRP team meetings (T. 974).

In its Reply Argument, B.C. Hydro continued to question whether the Commission has jurisdiction over the Utility with respect to IRP (T. 2847). The Utility stated that it is of the opinion that the Commission does not possess the jurisdiction to require it to seek approval of the IRP (T. 2847). Nonetheless, B.C. Hydro indicated that it would make every effort to comply with the production of IRP plans and meet the intention of the Commission's directions with respect to IRP and Power Smart (T. 1418).

The Energy Coalition was disturbed by the Utility's view that the regulatory authority of the Commission with respect to B.C. Hydro was limited. The Energy Coalition argued that such a view was incorrect, stating that:

> "If the Provincial Government wanted to exempt B.C. Hydro from regulation by the Utilities Commission it would have done so expressly in the Utilities Commission Act. Under section 3 of the Utilities Commission Act, the Commission is subject to directions issued by the Lieutenant Governor in Council, but B.C. Hydro has not identified any government direction that exempts it from the requirement to do IRP. ... B.C. Hydro already challenged the jurisdiction of the Commission to require IRP at last year's revenue requirement hearing. The Commission rejected this argument and asserted that it did have the authority under sections 28 and 51 of the Act. B.C. Hydro did not appeal this Decision; and until the Commission is successfully challenged B.C. Hydro has to learn to live with the fact that IRP is a mandatory feature of the current regulatory regime. ... B.C. Hydro has no discretion to decide that it will not do IRP because it thinks that the Government will be unsatisfied with the results." (T. 2650)

The CAC (BC) et al also disputed B.C. Hydro's assertion that the Utility was not bound by the Commission's determinations with respect to IRP and suggested that:

> "The Commission should apply economic sanctions against B.C. Hydro for its failure to follow Commission Directions. It is clear that B.C. Hydro does not consider itself bound to follow the Commission's directions. Despite the Commission having ruled against B.C. Hydro's assertion that IRP does not fall within the ambit of the Commission's regulatory powers (December 7, 1993, Decision p. 41) B.C. Hydro has conducted itself as if it does not have to comply with the Commission's instructions. Those who do not comply with the rule of law must expect sanctions to follow. In this case, we would

> suggest that the Commission consider disallowance of some portion of the utility's expenditures or additions to rate base." (T. 2617)

Commission Determinations

The Utilities Commission Act mandates the Commission to ensure that utilities provide adequate, safe and reliable service at fair, just and reasonable rates to consumers. Various sections of the Act, inclusive of sections 28, 35, 44, 48, 49, 51, 53, 65, 66 and 67 outline the Commission's responsibility to make certain that utilities undertake comprehensive planning to ensure that generation, transmission and distribution assets are installed by utilities so that the customer needs are fully satisfied and that rates are fully justified. The Commission developed and published its IRP Guidelines to make sure that utilities meet their responsibilities to customers utilizing the most appropriate planning techniques and public consultation, as are commonly required throughout North America. As noted previously, the Commission has developed the IRP process to ensure, through the associated Action Plan, that capital budgets and consequent rates are fully justified.

The current Energy Project Certificate Process and the issuance of Certificates of Public Convenience and Necessity ("CPCN") require the government and the Commission to ensure that projects are fully justified. The initial justification of these projects comes from the IRP. The IRP is also a critical component to the future approval of projects under the Environmental Assessment Act ("EAA"). The broad justification for projects under that legislation has been structured so that utility IRP's will provide the basic justification for utility projects. The new legislation will also require that all utility projects, inclusive of former EPC projects, obtain a CPCN from the Commission. That CPCN will not be issued until the Commission is assured that the project application remains the preferred resource addition for the utility after approval under the EAA with whatever conditions may be attached to the EAA certificate.

In failing to act on the directions given to it in the December 7, 1993 Decision, B.C. Hydro appears to have placed excessive reliance on a statement made by a Commission staff consultant, who reviewed the 1992 Electricity Plan, and found that it appeared to be reasonably consistent with general IRP principles. B.C. Hydro has ignored the rest of the statement, which said:

> "The Plan is lacking in the detailed explanation of planning processes, methodologies, and intermediate results that would enable us to conclude definitively that the Plan is a true integrated resource plan." (Barakat and Chamberlin Report dated July 30, 1993, p. 1)

In addition, B.C. Hydro has ignored the findings of that report which stated that the Electricity Plan was inconsistent with respect to BCUC Guideline #4 - Characterizing supply and demand options, Guideline #5 - Development of multiple integrated resource portfolios, and Guideline #6 - Evaluation and Selection of resource portfolios, and might be inconsistent with respect to Guideline #8 - Public input. (Barakat and Chamberlin Report, dated July 30, 1993, p. 2). The Commission notes that most of the deficiencies identified with respect to the current plan, and discussed in other sections of this Decision, relate to these Guidelines.

Since the 1994 hearing, B.C. Hydro has again re-organized. However, at the time of the hearing, the Commission considers the IRP to have been a key responsibility of the Corporate and Strategic Planning Group. Specifically, it was the responsibility of the Resource Planning Unit of Corporate and Strategic Planning to comply with the Commission's directions respecting IRP. Under these circumstances, the Commission determines, as a finding of fact under section 65(3) of the Act, that it would be unjust and unreasonable to allow the Utility to recover the full Resource Planning Unit budget in rates at this time. The Commission denies recovery of 5/12ths of the unit's $2.7 million budget for 1994/95 year (Exhibit 10) (i.e. from the start of the fiscal year up to the date of the hearing) but will allow the Utility to capitalize and defer the remaining amount for potential recovery in rates, upon satisfactory compliance with the Commission's directions with respect to IRP contained in this Decision. Should the Utility continue to fail to implement the Commission's directions respecting IRP, the Commission will consider the circumstances and may invoke its powers under Part 9 of the Act.

In the previous Decision, the Commission gave B.C. Hydro the option to convert the current Electricity Plan into a full IRP or to produce two documents, the current Electricity Plan and an IRP. B.C. Hydro chose to make certain changes to the Electricity Plan and file additional documents.

The Commission now directs B.C. Hydro to convert its Electricity Plan into an Integrated Resource Plan in line with the directions made at various points throughout this Decision. The Commission recognizes that the normal planning cycle employed by B.C. Hydro will not allow such conversion to take place by the usual release date of the Electricity Plan, i.e. the spring of 1995. Therefore, the Commission directs B.C. Hydro to postpone release of the Plan until the necessary changes are made. The Commission directs B.C. Hydro to make these changes and file the new IRP, with the Action Plan, by June 30, 1995. Further, the Commission directs B.C. Hydro to make monthly reports to the Commission on the progress it is making to comply with these directions. Should B.C. Hydro find that any of these directions are unclear, the Utility is directed to seek clarification from the Commission at the earliest possible date.

When preparing the new IRP, the Commission directs B.C. Hydro to take greater care to ensure that the document is more easily understandable to readers than is the current Electricity Plan.

B.C. Hydro should review the transcript of the hearing to determine where the current document did not adequately respond to the needs of the readers and make the necessary changes to clarify the explanations, e.g. how the IRP process is undertaken at B.C. Hydro and how it fits with strategic and corporate planning. The Commission believes that such changes will reduce future hearing time by providing necessary information to stakeholders. This should allow cross-examination to focus on those issues where there are true differences of opinion.

The Commission believes that the length of the hearing, of which this Decision is the subject, was unnecessarily prolonged by the failure of B.C. Hydro to comply with previous Commission directions with respect to IRP. This failure resulted in increased costs to the Commission and to Intervenors. The Commission disallows $300,000, or approximately 30 percent of B.C. Hydro's hearing costs, to reflect the excessive length of the hearing attributable to the nature of B.C. Hydro's IRP materials.

5.0 DEMAND-SIDE MANAGEMENT POWER SMART

5.1 Estimating Conservation Potential

B.C. Hydro's million dollar plus investment in the Conservation Potential Review (Exhibit 35) and the extensive investment of time and effort by the Collaborative Committee, can translate into usable results for IRP and Power Smart program design (Exhibit 3, BCUC 16-3 and Exhibit 70). Risk reduction will also be a benefit because the Power Smart investment can now be targeted with a greater certainty of useful and cost effective outcomes. B.C. Hydro agreed that the information gathered in the review regarding latest technology will help in the design of programs and in the reduction of DSM risk (T. 2092).

B.C. Hydro may become capacity constrained between now and the year 2010, and the conservation potential can be examined to identify programs to help meet the probable winter peak demand. B.C. Hydro indicated that it is using appropriate data and information from the Conservation Potential Review to help plan for capacity savings (T. 2091).

B.C. Hydro explained that the achievable conservation potential of 13,800 GW.h. forecast in the year 2010, for the "Integrated Scenario", (Exhibit 35 at II-3) includes 2,300 GW.h. of additional conservation that could be targeted by Power Smart over and above the current target of 4,400 GW.h. This estimate includes a revision for 1994 actual results and eliminates incremental fuel substitution from the data. The issue now becomes the development of an action plan to schedule this incremental

DSM resource into the IRP, bearing in mind that the policy options could include additional changes in rate design, legislation, information or Power Smart incentives (T. 896).

5.2 CONES and Avoided Cost

B.C. Hydro has provided an explanation of the translation of Cost of New Electricity Supply ("CONES") into the avoided costs that measure the benefits of individual Power Smart programs (Exhibit 3, BCUC4R 30-2 and the lead section of the July 1993 Power Smart 20 Year Plan - Exhibit 52). CONES is lower by virtue of including existing and committed Power Smart programs, that is, those programs in the July 1993 Power Smart 20 Year Plan. Each of the existing Power Smart programs are, however, evaluated using the CONES. This may be a reasonable way of evaluating increments to the existing and committed Power Smart portfolio, but it is not a reasonable way of evaluating the existing and committed Power Smart portfolio. The appropriate way of doing this is to develop multiple sets of CONES, with and without existing and committed Power Smart programs.

5.3 Fuel Substitution

The Commission directed B.C. Hydro to evaluate its fuel substitution programs, including long run incremental capacity and energy costs associated with natural gas, and to recognize the environmental impact of the substitution (B.C. Hydro Decision, December 7, 1993, at pp. 48 and 49).

In its BC Gas Decision, the Commission set out another key principle for the assessment of fuel substitution. The Commission directed that any fuel switching program must pass a test that incorporates the fuel cost implications (Decision dated August 12, 1994, p. 25).

B.C. Hydro indicated during the hearing that its fuel substitution programs would all be terminated by September 30, 1994 as a result of the Commission direction. B.C. Hydro further indicated its intention to assess future fuel substitution programs in the manner directed by the Commission (T. 1841). The Conservation Potential Review did not include the potential for fuel substitution (T. 2094).

The Commission believes that fuel substitution programs may have a valid role in conservation, provided the total impact of such substitution on both the utility losing load and the substituting utility is considered on a directly comparable basis. In the new year, the Commission intends to undertake a multi-utility initiative to address fuel substitution.

5.4 Power Smart Budget

The 1994 Electricity Plan was not amended for the changes in Power Smart with regard to additional conservation and the termination of fuel substitution programs (T. 1838).

B.C. Hydro explained that the 1994/95 budget does not contain an amount for Power Smart Inc., similar to the $659,000 loss that was recorded in the previous year, because six sevenths of the equity in that subsidiary was recently sold off to several other Canadian utilities (T. 48). Power Smart Inc. has its own employees and does not plan to depend upon B.C. Hydro staff (T. 1820).

The current forecast of expenditures on deferred capital for Power Smart is $57 million, whereas the July 1993 Power Smart Plan included $75 million for 1994/95 (T. 1808). The $57 million does not include some Power Smart expenditures that are charged as current OMA expenses. According to B.C. Hydro, 90 percent of Power Smart costs for 1994/95 are deferred (Exhibit 3, BCUC 10-3) implying that some $6 million may appear in current year OMA. However, the Power Smart Management states that only $3.1 million will be charged to OMA (Exhibit 10, p. 12). From this, the Commission concludes that total Power Smart expenditures for 1994/95 will be between $60 and $63 million.

The Commission notes that this is an increase of some 20 percent above 1993/94 costs in a year when rebate expenditures under Power Smart are forecast to decline by approximately $2 million (Exhibit 52, p. 31). The Management Plan shows the addition of some 20 FTE personnel over the same one year period (Exhibit 10). A footnote to the Work Plan Summary in Exhibit 10 indicates further increases for 1995/96 and 1996/97 "due to the ramp-up of the Power Smart programs". The Commission expects B.C. Hydro to provide more detailed explanations for the need for increased personnel.

5.5 DSM Accounting

B.C. Hydro currently uses a seven year amortization period for Power Smart capital costs, but in its 1994/95 Application has asked that this period be revised to ten years. The Utility provided evidence that the weighted average measure life is approximately 20 years (Exhibit 3, BCUC 10-2). WKP has used 20 years to this time but has indicated that it wants to change to 10 years, and BC Gas has recently suggested a five year amortization period.

A consistent way of accounting for DSM is becoming a priority (T. 1640, 1803). Consultation with other utilities and interested parties should lead to a consistent regulatory accounting practice for DSM. The Commission intends to address these issues within a multi-utility framework. Commission staff will establish a working group with participation from all utilities regulated by the Commission to attempt to reach consensus on DSM amortization periods and criteria. In the meantime, the Commission accepts the change from seven to ten years.

5.6 Program Evaluation

The evaluation budget is proposed to almost double from $1.3 million in 1993 to $2.4 million in 1995 (Exhibit 3, BCUC 4-3), largely as a result of increased evaluation effort in the commercial/industrial sectors.

The Commission is satisfied with B.C. Hydro's DSM Evaluation Plans, as outlined in Exhibit 60, but expects that B.C. Hydro will provide further appraisals and evaluation measurements as measurement programs mature.

6.0 OTHER MATTERS

6.1 Procedural Matters

Some Intervenors raised the issue of procedural matters in their submitted arguments. The Industrial Customers were critical of the quality of the Application in regards to detail and completeness vis-a-vis expenses claimed by B.C. Hydro. The CAC (BC) et al registered concern about a "lack of forthrightness" from the Utility.

Commission staff and Intervenors rely upon the Application, information submitted by the Utility in response to Information Requests, and testimony during the hearing, in formulating cross-examination and in making arguments to the Commission. It is incumbent upon the Applicant to provide the most relevant and comprehensive information in order for the Commission to have all the facts with which to reach its Decision. That being said, the Utility creates a vast amount of information within its own system, which, upon request, can be provided to the hearing process. Indeed, to ensure that large amounts of material are not produced and distributed, Commission staff request documents early in the process, in order to have such material on review.

One issue raised by some Intervenors is the lack of access to an electronic version of the Application, supporting material, Information Responses and financial schedules. Due to the large volume of materials required to support the Application, the Commission sees a definite saving of time and, consequently, expense to all parties, if material which was very likely prepared using a computer in the first place, was available upon request on an electronic medium.

While the text and graphic information in the Application should be currently available, one set of items that are apparently not prepared in any useful format are the financial schedules underlying the requested rate increase. Despite the fact that B.C. Hydro has IBM and Macintosh personal computer software standards for use within its offices (T. 417), it claimed that it was unable to provide the hearing participants with spreadsheet models of the Application's financial schedules, making revisions and "what if" scenarios impossible.

The Commission directs B.C. Hydro to augment the hard copy of its future applications and supporting material by providing information on computer disk wherever feasible. In the case of the financial schedules underpinning the future revenue requirement calculations, the Commission directs B.C. Hydro to provide that information on PC-based spreadsheets in Excel format, capable of being assessed and revised by hearing participants.

6.2 Subsidiary Operations

The principal subsidiaries of B.C. Hydro, all of which are wholly-owned, are Powertech Labs Inc. ("Powertech"), British Columbia Power Exchange Corporation, and British Columbia Hydro International Limited ("BCHIL"). B.C. Hydro also has a 50 percent joint venture interest in Power Serv Pacific Inc. ("Power Serv") and a 16 percent interest in Power Smart Inc. The financial results of the subsidiaries are reported on a consolidated basis in accordance with generally accepted accounting principles (Response to Exhibit 4, IND Question 21). Special Direction No. 8 requires that return on equity must be calculated using consolidated operating income from all sources.

The Industrial Customers cross-examined B.C. Hydro at length on the activities of the entities, principally BCHIL, Powertech and Power Serv. While originally BCHIL was intended to find areas to utilize the utility's engineering expertise overseas, it is also being used as a tool for bringing economic development benefits to British Columbia (T. 39). B.C. Hydro provides employees to BCHIL as available, and charges fully-loaded costs for these services. BCHIL, in turn, charges its clients at market rates. BCHIL made a small profit in fiscal 1993/94 and expects more significant activity in the future.

The Commission is concerned that future, much larger, offshore projects, involving more than the provision of engineering services, could add significant risk to all the Utility's customers if inappropriate contracts are concluded. **The Commission expects BCHIL to expressly protect the Utility's domestic customers from financial risk arising from BCHIL's activities outside British Columbia.**

Powertech is a research and development company with specialized testing facilities serving electric utilities and related heavy industries. Its principal customer is B.C. Hydro. Power Serv Pacific is an electrical equipment repair facility with about 75 percent of its work coming from B.C. Hydro. Together, these two non-utility companies were forecast to lose some $1.6 million in fiscal 1994/95. (B.C. Hydro's share being $1.4 million). A subsequent August 1994 variance report (Exhibit 42) showed these losses are predicted to escalate to approximately $4.5 million before the end of the 1994/95 year (B.C. Hydro's share being $3.7 million). B.C. Hydro stated under cross-examination that studies were being completed with a view to restructuring and lowering the predicted losses.

In the past, B.C. Hydro has borne fully the Power Smart Inc. losses, but its reduced financial interest in Power Smart Inc. means that its share of any future losses will be reduced to 16 percent.

The Industrial Customers argued that all these entities perform non-utility activities which impact ratepayers and the return to the Province and they, and their projects, should be regulated in the same manner as if they were a division of the company itself. The Industrial Customers submitted that either the units should be earning an appropriate return or ratepayers should not have to pay for their activities (T. 2573).

B.C. Hydro's response was that BCHIL does recover its costs, that the prime focus of Powertech is to carry out research and development, that attempts are being made to reduce losses in other areas and that the Commission has a limited jurisdiction over non-utility activities (Reply Argument T. 2838). The Commission view is that, just as electricity customers are generating a return on Utility assets through their rates, so should non-utility businesses be generating a return from their operations so long as their results are consolidated with those of the Utility for ratemaking purposes.

For the 1994/95 fiscal year, B.C. Hydro's accounts, which form the basis of its rate Application, incorporate the predicted net losses from Powertech and Power Serv. In the case of Powertech, Plan 1994/95 includes a forecast $1.1 million loss at a time of relatively buoyant economic conditions for B.C.'s heavy industries. Subsequent projections show these losses to be accelerating.

The Commission considers the losses in Powertech to reflect a lack of prudence by B.C. Hydro in the management of the Powertech subsidiary and, it denies the inclusion of $1.1 million in 1994/95 OMA expenses for ratemaking purposes.

The Commission recognizes that, in the case of Power Serv, a joint-venture operation, B.C. Hydro does not have the same freedom of action as it does in the case of Powertech. Nevertheless, it expects B.C. Hydro to take immediate steps to address the losses being incurred in Power Serv.

The Commission orders B.C. Hydro to submit a proposal for the organizational separation of non-utility businesses (generally referred to as non-regulated businesses) ("NRB's"), from its core, regulated utility services. The proposal shall be submitted by May 30, 1995. At the same time, B.C. Hydro shall develop policies covering an appropriate code of ethics, accounting procedures

and the need for protection against cross-corporation confidential information flows. In this connection, the separation of NRB's from B.C. Gas Inc. may provide useful guidance to B.C. Hydro (Decision dated August 5, 1992).

6.3 Kerr Complaint

The quality of service to the West Chilcoltin area was the subject of a complaint by Dale and John Kerr of Tatlayoko Lake (T. 502). Mr. Kerr complained of numerous outages and voltage spikes and surges which affect the quality of his power. However, this area is fed from a very long and exposed single phase distribution line which originates in Williams Lake. B.C. Hydro has taken steps to improve this line, as outlined in a letter of April 25, 1994 to the Commission, and this correspondence was attached to Mr. Threlkeld's rebuttal testimony. Power quality and reliability are interrelated issues, both of which can be affected by the robustness of the delivery system. Some efforts made to improve the reliability of a feeder (for example, by increasing fuse sizes to eliminate spurious interruptions caused by tree branches) can adversely effect power quality by replacing actual outages with voltage dips. Considering that this line is over 200 km long, and in an area subject to frequent and severe seasonal electric storms, any significant improvement in reliability or power quality would require an extensive rebuild at very high costs. The Commission is satisfied that B.C. Hydro has acted in a prudent manner in addressing this problem.

However, Mr. Kerr also outlined some of the opportunities for economic growth in the area which may be jeopardized by the existing level of power available. The nearby community of Anahim Lake, roughly 350 km west of Williams Lake, is not connected to the provincial grid and, according to a report prepared for B.C. Hydro in 1990, the existing diesel generators are marginally adequate for the area's energy needs (Exhibit 20).

Mr. Kerr explained that he has been trying to obtain a Request for Proposal on a small hydro IPP in the area for the past 11 years. B.C. Hydro did issue an RFP for Anahim Lake in 1989, but it was not responded to. Mr. Kerr felt the Utility did not understand the difficulties of accessing, and responding to, such information in a remote area. However, B.C. Hydro does intend to release another RFP for that area shortly, once it completes negotiations with respect to its Queen Charlotte Islands RFP (Exhibit 1, Tab 15). Mr. Spafford noted that B.C. Hydro could not acquire a specific resource without giving others the opportunity to compete. This requires the Utility to justify the need through its resources acquisition policy before issuing an RFP (T. 933).

6.4 Distribution Extension Policy

The Commission is concerned that the current B.C. Hydro distribution extension policy may not be consistent with recent determinations made by the Commission for other utilities. Essentially, it is the objective of the Commission that any system extension reflect the total social cost of extending service.

The Commission directs B.C. Hydro to review the principles underlying its distribution extension policy to ensure that they are compatible with its IRP methodologies. The review should include consideration of the extent to which some communities may be better served in ways other than via connection to B.C. Hydro's grid, for example, through the application of distributed generation technologies. The Commission proposes to undertake a general review of extension policy, within a multi-utility framework, during the coming year.

7.0 REVENUE REQUIREMENTS AND RATE DESIGN

7.1 Revenue Requirements

Table 7.1 summarizes the revenue requirement impacts of the Commission's determinations in this Decision, as follows:

- **Sales revenue has been based on normal weather forecasts.**
- **Powertech projected losses in 1994/95 are found to be imprudent.**
- **OMA expenses related to the Resource Planning Unit are partially disallowed.**
- **OMA is reduced by 1%.**
- **Other expenses are adjusted to reflect reduced tax and increased cost of energy.**
- **Finance charges have been increased.**
- **Electricity trade income reflects revenue consistent with Special Direction No. 8.**

Table 7.1

The Commission denies the requested rate increase and orders a full refund with interest.

7.2 Rate Design

In its Decision dated December 7, 1993, the Commission directed B.C. Hydro to flatten its residential rates in two approximately equal steps. The first step was to be effective with consumption from January 1, 1994 and the second step was to be achieved with the next rate application, i.e. April 1, 1994. In particular, B.C. Hydro was directed that the entire amount of any revenue requirement increase applicable to residential customers was to be applied to the trailing block rate and that the initial block and trailing block rates were to be adjusted by whatever additional amounts were necessary to obtain the objective (December 7, 1993 Decision, p. 54).

Similarly, the Commission directed B.C. Hydro to achieve flat rates for general service customers by the time of the 1995/96 fiscal year (i.e. in three steps) with the first step to commence effective with consumption starting January 1, 1994. In reaching this goal, the Utility was directed to attempt to achieve the smoothest possible annual bill increases for the majority of customers, even if this resulted in some bill decreases to low use customers. Further, the Utility was directed to maintain articulation between rate schedules serving customers taking under 35 kW and customers taking 35 kW and over. Articulation ensures that customers at the crossover point are indifferent to whether they are served on one rate schedule or the other. The Commission indicated it would examine the strategy and resulting proposals as part of the 1994 revenue requirements hearing. (December 7, 1993, Decision, p. 55) The Decision did not specify whether the flat rates were for the energy charge, the demand charge where applicable, or both charges.

7.2.1 Residential Rates

In the current Revenue Requirements application, B.C. Hydro indicated that the Commission's directions with respect to residential customers resulted in bill decreases up to 5.5 percent and bill increases up to 10.1 percent effective January 1, 1994. The second step, effective April 1, 1994 on an interim basis, assumed an average rate increase of 2.8 percent, and resulted in bill decreases up to 6.5 percent and bill increases up to 8.1 percent. For fiscal 1995/96, B.C. Hydro assumed an illustrative average rate increase of 1.9 percent, which would be applied solely to the flat energy charge to better reflect the long run marginal cost of supply. The basic charge would be left unchanged.

In Section 7.1 of this Decision, the Commission has denied all of the requested increase in B.C. Hydro's revenue requirement application.

The Commission directs B.C. Hydro to revise its rates for residential service to reflect the Commission's Decision on revenue requirements.

7.2.2 General Service Rates

B.C. Hydro has two basic general service rates. Rate Schedule ("RS") 1220 is for customers with less than 35 kW of demand per month. On August 1, 1992, it consisted of a basic charge, a declining block (3 step) energy rate and no demand charge. RS 1200 is for customers with 35 kW or more of demand per month. On August 1, 1992, it consisted of a basic charge, identical to RS 1220, a four step declining block rate, the first three steps of which, up to 30,000 kW.h/month, were identical to RS 1220, and an inclining block three step demand charge. The first step of the demand charge covers the first 35 kW and was set at $0.00. These structures ensured that customers whose monthly demand was approximately 35 kW were indifferent as to whether they were billed on RS 1220 or RS 1200.

Effective January 1, 1994, the Commission approved rates which maintained the same basic structure but reduced the initial energy block rates and increased the trailing energy block rates so that the energy charge for both RS 1220 and RS 1200 moved closer to a flat rate. In addition, the structure reduced the amount of kW.h for which the energy charge was the same under both schedules, i.e. the articulated amount, to 20,000 kW.h. The demand charge applicable to RS 1200 was left unchanged.

Effective April 1, 1994, interim rates were approved which incorporated the requested 2.8 percent increase. Again, the same basic structure was maintained for both RS 1220 and RS 1200; however, the entire amount of the increase applicable to general service customers was applied to the energy charges, such that the energy rates were made flatter. In addition, the articulated amount was reduced to 18,000 kW.h/month. B.C. Hydro stated that the articulated amount was reduced to 18,000 kW.h/month to maintain the revenue split that the Utility collects from both customer classes and to spread the increase across the rate schedules as much as possible (T. 2505). The demand charge applicable to RS 1200 continued to be left unchanged.

If the April 1, 1994 rate changes had been confirmed, bill impacts for RS 1220 customers would have ranged from less than 1 percent , and in some cases bill reductions, for the approximately 75 percent of customers who consume less than 2,500 kW.h/month, to approximately 10 percent for the 2 percent of customers who consume in excess of 25,000 kW.h/month. For RS 1200, bill impacts would have ranged from effectively nothing for large volume customers to approximately 10 percent for lower volume customers. B.C. Hydro was unable to indicate what the bill impacts would be in the absence of a 2.8 percent revenue requirement increase (T. 2506).

The next rate change is contemplated to take place April 1, 1995 and, according to the 1993 Commission order, should result in flat rates. For RS 1220, B.C. Hydro proposed to apply the entire amount of any increase (estimated in the Application at 1.9 percent) to the energy charge in such a way as to result in a single flat energy charge. Under this scenario, B.C. Hydro estimated that customer bill impacts would range from 0% for those who consume less than 2,500 kW.h/month, to over 15 percent for customers who consume more than 25,000 kW.h/month. The Industrial Customers indicated that they found it counter-intuitive that the highest load factor customers should be getting hit with what they characterized as very extreme rate increases year after year (T. 2486).

For RS 1200 (35 kW and over), B.C. Hydro has indicated that it is not possible to comply with the Commission's Order to achieve flat rates, maintain appropriate articulation with RS 1220, and collect the appropriate share of the interim revenue requirement increase from each class of general service customer (T. 2501). Therefore, B.C. Hydro has proposed for April 1, 1995 that the RS 1200 energy charge be a two-step declining block rate. The first step would be set equal to the RS 1220 energy charge and apply to the first 18,000 kW.h, in order to achieve an appropriate level of articulation, while the second step would be approximately one-half of the first step, in order to achieve the appropriate revenue contribution. In addition, B.C. Hydro proposed to maintain the inverted block structure for the demand charge, with the charge for the first 35 kW set at $0.00 to assist articulation, and the charge for the third step being twice the second step. B.C. Hydro stated that retention of the inverted demand charge helped to levelize the energy charge for a customer at the boundary between the two rate classes (T. 2504).

Bill impacts for RS 1200 customers were expected to range from approximately negative 4 percent, for high demand, low load factor customers, to plus 12 percent for low demand, medium load factor customers. For most levels of demand, impacts would range from negative 2 percent to plus 2 percent.

The Commission is concerned that the bill impacts associated with the movement to flat rates by 1995/96 for RS 1220 customers could be, in certain instances, inappropriate.

The Commission directs B.C. Hydro to extend the time frame over which a flat rate for RS 1220 is achieved by one year to fiscal 1996/97. Further, the Commission directs B.C. Hydro to revise its RS 1220 for 1994/95 to reflect the Commission's Decision with respect to the current revenue requirement. In adjusting the rate schedule for 1994/95, BC Hydro is directed to ensure that no customer bills are increased by more than the amount which was allowed in the interim rates.

In addition, the Commission recognizes that difficulties exist in implementing a flat rate schedule for RS 1200 customers, while at the same time achieving appropriate articulation with RS 1220 and leaving the revenue requirement shares unchanged between the two classes of customers.

The Commission accepts B.C. Hydro's general approach to this problem as being appropriate but will examine the rate schedules as they are submitted for approval. For 1994/95, the Commission directs B.C. Hydro to file revised rate schedules based on no revenue requirement increase. As with RS 1220, in adjusting the rate schedule for 1994/95, BC Hydro is directed to ensure that no customer bills are increased by more than the amount which was allowed in the interim rates.

7.2.3 Other Issues

As indicated in the hearing, the Commission does not believe that the consideration of rate increases can avoid the question of rate design (T. 2478). Accordingly, the Commission questioned B.C. Hydro concerning the basis of its current policy of applying the requested revenue increases to rates on an across-the-board basis. B.C. Hydro agreed that the costs to serve different classes of customers do not necessarily rise at the same time. The reasons for this included the impacts of particular Power Smart programs and the fact that costs of distribution may be rising differently than the costs of generation (T. 1880). For example, B.C. Hydro noted that the rate impact measure test indicated that industrial Power Smart programs acted to decrease the revenue requirement, while residential programs acted to increase the revenue requirement (T. 1858). This would imply that residential rates should increase at a greater pace than industrial rates. Nonetheless, B.C. Hydro indicated that its latest Fully Allocated Cost of Service study, based on 1991/92 data, showed that there was no undue cross-subsidization between customer classes. Further, the Utility indicated that it undertook new cost of service studies every two years, had a monitoring program to feed better information into the studies and was reviewing the methodology it used. B.C. Hydro agreed to send a copy of the new FACOS study to the Commission when it was completed.

The Commission directs B.C. Hydro to file a copy of the latest completed Fully Allocated Cost of Service study within two weeks of the receipt of this Decision and to file updated studies as they become available.

Several Intervenors expressed interest in other Rate Design issues during the course of the hearing including the appropriate application of time-of-use and seasonal rates. The CAC(B.C.) et al inquired as to the advantages that seasonal rates would have for IRP. Similarly, Ms. Bechler asked whether B.C. Hydro was considering rate design structures that encouraged efficiency (T. 2490).

The Commission shares the concerns of Intervenors that B.C. Hydro should bring forth new rate design proposals as part of its IRP process. The Commission directs B.C. Hydro to file a report with the Commission by February 28, 1995 which describes the various intra-class rate design options available to the Utility. The report, which should examine items such as performance based hook-up fees, inverted rates, time-of-use rates, etc., should be considered by the new IRP consultative committee as part of a package of strategies to be included in the June 30, 1995 filing of the IRP.

Dated at the City of Vancouver, in the Province of British Columbia this 24th day of November, 1994.

Original signed by:
Dr. M.K. Jaccard
Chairperson

Original signed by:
Mr. F.C. Leighton
Commissioner

Original signed by:
Mr. K.L. Hall
Commissioner

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ALLWEST COURT REPORTERS LTD.	Court Reporters & Hearing Officer

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