BRITISH COLUMBIA UTILITIES COMMISSION

BRITISH COLUMBIA HYDRO
AND POWER AUTHORITY
AND
BRITISH COLUMBIA POWER
EXCHANGE CORPORATION

ENERGY REMOVAL CERTIFICATE APPLICATION

REPORT AND RECOMMENDATIONS
to the
LIEUTENANT GOVERNOR IN COUNCIL

JUNE 30, 1992

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

THE UTILITIES COMMISSION ACT,

S.B.C. 1980, C. 60, AS AMENDED

AND

IN THE MATTER OF

AN APPLICATION BY

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

and

BRITISH COLUMBIA POWER EXCHANGE CORPORATION

FOR AN ENERGY REMOVAL CERTIFICATE

REPORT AND RECOMMENDATIONS
TO THE
LIEUTENANT GOVERNOR IN COUNCIL

June 30, 1992

BEFORE:

F.C. Leighton, Chairman
P.C. Bradley, Commissioner
M.K. Jaccard, Commissioner
P.R. West, Commissioner

June 30, 1992

TO THE LIEUTENANT GOVERNOR IN COUNCIL

May It Please Your Honour:

Pursuant to Sections 24(1)(a) and 25 of the Utilities Commission Act, the Minister of Energy, Mines and Petroleum Resources referred the Application of the British Columbia Hydro and Power Authority and the British Columbia Power Exchange Corporation for an Energy Removal Certificate to the British Columbia Utilities Commission for review.

The Commission was directed to hear the Application in Public Hearing in accordance with the Minister's Terms of Reference. The Hearing was held from April 6, 1992 to May 14, 1992.

We, the Division of the Commission with responsibility for such review, have the honour to submit our report and recommendations.

Respectfully,

BRITISH COLUMBIA UTILITIES COMMISSION

Original signed by:
Frank Leighton, Chairman of the Division

Original signed by:
Mark Jaccard, Commissioner

Original signed by:
Paul Bradley, Commissioner

Original signed by:
Paul West, Commissioner

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EXECUTIVE SUMMARY

This summary provides a general overview of the report, highlighting its key findings. For the sake of brevity and readability, less technical language is used and certain details have been omitted. Accordingly, this summary does not form part of the Commission's formal response and readers are referred to the report itself for the complete text.

THE APPLICATION

B.C. Hydro and POWEREX made a joint Application on April 19, 1991 to the Minister of Energy, Mines and Petroleum Resources for renewal of their Energy Removal Certificate which is currently due to expire on September 30, 1992. As applied for, the new Energy Removal Certificate would allow the Applicants to export electricity from British Columbia until September 30, 1997 at annual limits of: 2,300 MW to the United States and 1,200 MW to Alberta of firm power; 6,000 GW.h of firm energy; and 25,000 GW.h of interruptible energy (less concurrent firm energy).

THE HEARING AND ENERGY REMOVAL CERTIFICATE RECOMMENDATION

The Minister requested that the Commission review the application in a public hearing according to specific evaluation criteria. The hearing commenced on April 6, 1992 and terminated with final argument on May 14, 1992. The Commission was required to report its findings and recommendations to the Cabinet by June 30, 1992. The Commission recommends the granting of the Energy Removal Certificate, subject to the terms and conditions summarized below.

DETERMINATION OF THE ELECTRICITY SURPLUS FOR EXPORT: EFFECT OF EXPORTS ON RELIABILITY AND SECURITY OF SUPPLY

The Application is for permission to export short-term surplus electricity; that is, surplus electricity from facilities built to serve domestic customers. In determining B.C. Hydro's short-term firm electricity surplus, the Commission recommends excluding any surplus due to future investments that are avoidable. Using this principle to calculate the removable surplus, three years should be the maximum duration for firm energy sales contracts allowable as short-term exports. With this limitation, and ministerial review of all contracts exceeding one year, the Energy Removal Certificate should not adversely affect reliability and security of electricity supply to British Columbians.

DOMESTIC AND EXPORT MARKETING OF SURPLUS ELECTRICITY

The Commission reviewed proposals by the Applicants to replace the current offer mechanism, which allows domestic utilities to view and intercept any export contract. While the Commission favours the proposed Power Exchange Operation, for export sales of less than one year, a number of guidelines are suggested to ensure fair market access for domestic customers. For export sales of greater than one year, the Commission recommends that, although domestic utilities need not view export contracts, they should be provided with price and quantity information and priority access to all major blocks of energy offered for export. The Commission also recommends that approval of all export sales be subject to price tests, ensuring recovery of the incremental cost of production and an allowance for adverse environmental impacts.

ENVIRONMENTAL IMPACTS OF EXPORTS-
OTHER THAN FROM BURRARD THERMAL

For the operation of hydraulic facilities, the Commission found that it is difficult to segregate environmental effects attributable to exports. Available information suggests that the incremental effects of exports will not be significant. However, the Commission suggests the need for further study, and recommends that B. C. Hydro undertake a comprehensive system review of its hydraulic operations with a view to identifying environmental and social impacts of generation and effective mitigation measures.

The Energy Removal Certificate may entail the export to the U.S. of significant quantities of coal-generated electricity from Alberta. The Commission recommends that the Applicants be directed to develop, together with other interconnected utilities, a mechanism for incorporating environmental externalities from different energy resources into the price of electricity and into dispatch decisions.

To ensure that the environmental impacts of export generation are fully taken into account, the Commission recommends that the Minister of Energy consult with the Minister of Environment in the approval of firm energy export contracts longer than one year.

ENVIRONMENTAL IMPACTS OF EXPORTS - THE BURRARD THERMAL PLANT

Because of the multiplicity of factors affecting the operating levels of each component of the B.C. Hydro system, the Commission found it difficult to precisely determine the incremental operation of the Burrard Thermal plant for exports. Even if this were known, scientific uncertainties about the effects of air emissions from the plant made it impossible to definitively determine and cost the incremental environmental impacts in the Lower Fraser Valley of exports under this Energy Removal Certificate.

However, several general observation are possible: exports are likely to lead to an increased use of Burrard, especially in low water years; NO_X emissions from Burrard would contribute to the production of ozone in summer months in the Lower Fraser Valley; this ozone has several detrimental effects on the health of humans, animals and vegetation. Applying the precautionary principle, the Commission recommends that until the GVRD and other relevant agencies have achieved consensus on targets and policies for reducing NO_X emissions, a cap be placed on the NO_X emissions from the Burrard plant during the critical summer period of May to September. Caps are proposed for summer 1993 and 1994. Further caps could be set at levels that meet GVRD objectives, while allowing B.C. Hydro the flexibility to either reduce operation of the plant or undertake emission reduction investments. With these restrictions, the Commission accepts the continued availability of Burrard in support of exports.

NET BENEFITS TO THE APPLICANTS AND BRITISH COLUMBIA

A benefit cost analysis of this Energy Removal Certificate must rely on estimates of future prices, costs, and quantities, because existing contracts encompass only a small portion of the potential removals. A net revenue estimate suggests significant positive return to both the Applicants and the Province from electricity trade. Including externalities (for a social estimate) is difficult, again because of the early stage of research in the field of environmental costing. However, the Commission's analysis indicates that environmental impacts of air emissions would have to be at the high end of current estimates of environmental externalities before exports that rely on Burrard would lead to negative net benefits for the Province. Also, preliminary calculations, for illustrative purposes, suggest that a seasonal cap on Burrard emissions may be a more cost-effective means of achieving improvement of environmental quality than mandating a pollution control investment at the plant. This is because, unlike most facilities, the plant's value to the B.C. Hydro system is not necessarily dependent upon its full-time operation.

1.0 INTRODUCTION

1.1 The Application and the Terms of Reference

This report contains the British Columbia Utilities Commission's ("BCUC", the "Commission") findings and recommendations on the Application by the British Columbia Hydro and Power Authority ("B.C. Hydro") and British Columbia Power Exchange Corporation ("POWEREX"), the "Applicants", to renew their jointly-held energy removal certificate ("ERC") so that they may continue to export electricity from British Columbia to the U.S. and Alberta. The Applicants have applied for an ERC valid until September 30, 1997. Their current ERC expires on September 30, 1992.

The Application, made pursuant to Section 23 of the *Utilities Commission Act,* (the "Act"), requests an ERC that would allow the export of surplus short-term firm power of up to 2,300 MW to the U.S. and 1,200 MW to Alberta and total short-term firm energy in amounts up to 6,000 GW.h in each year of the term.[1] B.C. Hydro/POWEREX also requested that the ERC allow the export of interruptible energy in amounts up to 25,000 GW.h in each year of the term less any short-term firm exports made by the Applicants. The various types of transactions by which the electricity would be exported are: sale, exchange, storage arrangements, adjustment and carrier transfers. Section 1.5 of this report provides an explanation of these different types of transactions.

B.C. Hydro was established as a provincial Crown Corporation in 1962 to generate, transmit and distribute electricity. Its wholly-owned subsidiary, POWEREX, was initially formed in 1988 to manage the development of long-term electricity exports from private sector projects. The provincial government is currently reviewing its policies regarding long-term private sector electricity exports so this aspect of POWEREX's mandate has been held in abeyance. In the meantime, POWEREX has been assigned responsibility for marketing and co-ordinating short-term electricity trade for B.C. Hydro.

According to the Application, POWEREX will be primarily responsible for electricity export sales for B.C. Hydro with the exception of border accommodation export orders held by B.C. Hydro for Point Roberts in Washington State and Hyder, Alaska. In addition, POWEREX will handle most storage transactions with neighbouring utilities in Alberta and the U.S.

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1 For reference, the annual domestic consumption of electricity in B.C. currently exceeds 40,000 GW.h.

POWEREX has also proposed the formation of a Power Exchange Operation ("PEO") to manage short-term (up to one year) and spot power transactions both within and outside the Province. (Further details of these two entities - POWEREX and the PEO - are found in Chapter 4.0.)

B.C. Hydro will be primarily responsible for the exchange, storage, adjustment and carrier transfers, electricity for coordination, and other support transactions with utilities in the U.S. In addition, B.C. Hydro will handle Canadian obligations under the Columbia River Treaty and the Skagit Valley Treaty.

The Application further indicates that the sources of supply for the electricity exports sales will be: surplus generation from the B.C. Hydro integrated system, short-term purchases from other electricity producers in British Columbia, short-term purchases from Alberta utilities, and carrier transfers from other producers in British Columbia and Alberta. Figure 1 shows the location of the major features of the B.C. Hydro system.

The Application was submitted on April 19, 1991, to the Minister of Energy, Mines and Petroleum Resources. The Minister, pursuant to Section 24 of the *Act,* referred the Application to the BCUC for review by way of a public hearing in accordance with Terms of Reference that were prescribed in a letter to the BCUC dated November 19, 1991. The complete Terms of Reference as well as the letter from the Minister are set out in Appendix 1 to this report.

The Terms of Reference require the BCUC to hear the Application by way of a public hearing pursuant to Section 25 of the *Act* and submit a report to the Lieutenant Governor in Council with recommendations on whether the ERC should be issued and any conditions that should be attached. Briefly summarized, the evaluation criteria in the Terms of Reference by which this Application was reviewed require the BCUC to:

(i) Assess the net benefits to the province and the Applicants;

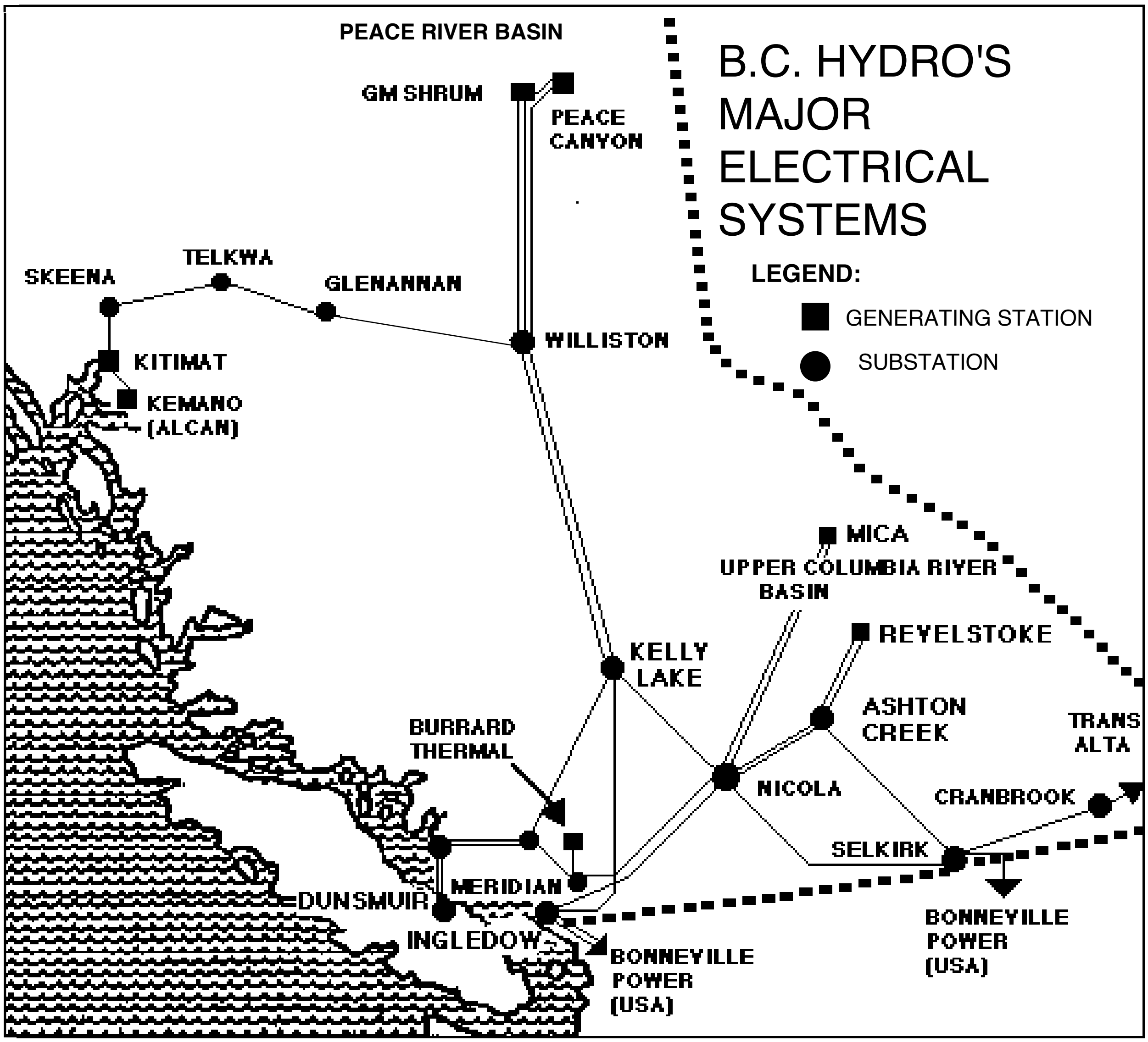
(ii) Ensure that the reliability and security of the electricity supply to British Columbians would not be adversely affected;

(iii) Assess the current provincial procedures for determining B.C. Hydro's removable short-term energy surplus;

(iv) Advise on the time-frame that should be considered short-term for the purpose of the Application;

FIGURE 1

B.C. HYDRO INTERCONNECTED SYSTEM



(v) Determine whether the present offer mechanism, by which energy is first offered to domestic inter-connected utilities before export, is the best method to demonstrate removable surplus and fair market price; and

(vi) Assess the environmental impacts from the proposed removals and whether the Applicants' operating practices are adequate to mitigate any unacceptable impacts, and in particular:

  (a) review the role of B.C. Hydro's Burrard Thermal Generating Station ("Burrard") in serving exports;

  (b) assess the incremental impact of air emissions on the Lower Mainland airshed from Burrard's use in support of exports;

  (c) consult with the Ministry of Environment, Lands and Parks ("Ministry of Environment") and the Greater Vancouver Regional District ("GVRD") to assess the adequacy and reliability of any studies/modelling which may be necessary to assess the environmental impact of the operation of Burrard.

The initial date set out in the Terms of Reference for reporting to the Lieutenant Governor in Council was February 28, 1992. This deadline was extended at the BCUC's request to March 30, 1992. The hearing was initially scheduled to commence on February 11, 1992 by BCUC Order No. G-1-92. Following a request by the Applicants for an extension of time, the BCUC rescheduled the hearing to commence on April 6, 1992. The Minister also extended the deadline for filing the report to June 30, 1992 and extended the expiry dates of the existing ERC to September 30, 1992. Thus, the ERC, which was originally intended to cover six years, is referred to in this report as a *five year* ERC.

1.2 The Public Hearing

As explained in the previous section, this Application was reviewed by the BCUC during a public hearing held pursuant to Section 25 of the *Act*. This procedure was unique in that it was the first time there had been a B.C. Provincial public hearing to consider an ERC concerned with the electricity export trade. The schedule for the hearing and the application procedure were established by Commission Order No. G-1-92, which was issued on January 6, 1992. This, and a subsequent rescheduling Order No. G-17-92 issued on February 4, 1992, are attached to this report as Appendix 2.

Prior to the hearing, the Commission staff convened meetings with scientific and technical personnel of B.C. Hydro/POWEREX, the GVRD, the Ministry of Energy and the Ministry of Environment to discuss the matters set out in Term of Reference 6(c). These meetings were in the nature of technical consultations to assist in the identification of issues to be explored in the hearing related to assessment of the environmental impact of the operation of Burrard.

For the most part, the hearing was held at various locations in Vancouver. There were also regional sittings in Coquitlam and Chilliwack on April 13 and 14, 1992, respectively, at which the BCUC heard the submissions of local area residents. The out-of-town sittings were added to the hearing process at the request of a number of intervenors, most notably the GVRD.

The hearing lasted for 23 hearing days with final argument being concluded on May 14, 1992. A diverse range of interested parties participated in the hearing by either filing written comments or attending the hearing sessions. The participants included: representatives of Lower Mainland municipalities and regional governments, provincial government officials, consumer and rate-payer associations, an aboriginal people's group, environmental organizations, union representatives, agricultural associations, industry representatives and concerned citizens. Chapter 2.0 of this report outlines the concerns and issues raised by these interested parties during the hearing.

In addition to this more formal public hearing, B.C. Hydro/POWEREX also undertook a public involvement program as part of their application process. This program preceded the filing of the Application and began in October, 1990. The initial phase of the program comprised discussions with representative industry groups followed by a second phase during which there were a number of public participation initiatives throughout the province. These public participation initiatives included newspaper advertisements and media releases, public open house sessions, and discussions with representatives of environmental groups, business, industry, and government (Exhibit 1, Tab 9).

1.3 Special Challenges Posed by the Application

The Application and Terms of Reference presented a particular difficulty in that the Commission was asked to assess the incremental effects of electricity exports from a complex, integrated electricity system. The evidence in the hearing provided some methodological suggestions for addressing this problem, but did not resolve it.

1.3.1 <u>Tracking Export Energy Sources from an Integrated System</u>

A primary difficulty is the near impossibility of tracing flows of electricity from B.C. Hydro's multiple generating sources to the export interties. Dispatch of energy from each of B.C. Hydro's thirty four domestic sources is performed by a system computer model, which identifies successive least marginal cost sources capable of serving specific load demands.

The major sources of this integrated generating/supply system are (Figure 1):

(i) Hydroelectric

- Peace River Basin
- Columbia-Kootenay River basin
- Fraser River basin (Bridge River)

(ii) Thermal

- Burrard

(iii) Purchases from interconnected Alberta utilities

(iv) Domestic purchases (eg. Alcan).

Each river basin has a number of discrete generation sources. The Columbia-Kootenay basin has a particularly large number of generating stations, many using the same water, and most are closely interdependent.

Although the primary role of Burrard is to meet load demand of the Lower Mainland, it can equally well be used to support the refilling of hydroelectric reservoirs or to support export sales depending on the seasonal availability of natural gas.

Since the flow of individual electrons from the various integrated generating sources to the export interties cannot be tracked, it is necessary to assign production to export in a retrospective notional way. This is done by assigning the highest cost marginal source in operation at the time of export to that market. This inability to link specific generating sources to exports particularly complicates consideration of the role of Burrard in relation to electricity exports.

1.3.2 Identifying the Incremental Effects of Exports

The Terms of Reference directed the Commission to assess the *incremental* effects of electricity removals under this ERC on:

- security and reliability for B.C. Hydro's domestic customers,
- net benefits to the Applicants and the province,
- environmental impacts due to changes in the export-related use of electricity facilities.

In an effort to address the terms of reference, many of the pre-hearing questions by Commission staff and intervenors, and much of the six weeks of the hearing, were devoted to the particular problem of estimating those incremental effects that could be attributed to electricity removals under this ERC. However, by the end of the hearing many questions remained unresolved.

The Applicants argued that they were confident in stating that the ERC would not adversely affect security and reliability for B.C. Hydro's domestic customers, and that electricity trade under the ERC would have positive net financial benefits. However, they also argued that they were unable to completely estimate all of the ERC's incremental financial effects, nor were they able to estimate monetary values for incremental environmental effects. According to the Applicants, the estimation of incremental effects is especially problematic because of the many types of electricity removals (exchange, treaty obligations, firm, interruptible, etc.), each involving several decisions (sometimes daily) affecting the operation of B.C. Hydro's entire electricity system. Only in hindsight, and by rather crude analysis, could one allocate a proportion of financial and environmental effects to ERC removals.

This left the Commission and intervenors with two options.

(i) Attempt to use what data is available to make an approximate forecast of the realistic range of incremental financial and environmental effects of the ERC.

(ii) Look at the entire B.C. Hydro system, focusing, for example, on the way in which reservoirs are operated to meet electricity needs, regardless of the export component of changes in reservoir operation.

The Commission favoured the first option. The second option would have resulted in a review of the entire B.C. Hydro system, clearly beyond the intent of the Terms of Reference. However, at times frustration with the lack of data for estimating even a range of incremental effects lead the Commission to allow and consider evidence on the operation of the entire B.C. Hydro system or on individual facilities such as Burrard. To some extent, this move to a broader mandate was an inevitable result of both the Terms of Reference and the Applicants' argument that incremental effects could not be isolated from operation of the entire B.C. Hydro system.

However, the Commission did ensure that evidence and recommendations were restricted to short-term issues of operating the existing B.C. Hydro system, thereby excluding issues related to long-term development of supply and demand-side resources. These latter items are clearly beyond the Terms of Reference.

1.4 The Hearing Setting: A Time of Transition in Energy Matters

Advisory panels are frequently challenged by the obligation to make recommendations at a time in which issues and the state of knowledge are evolving rapidly, and for this panel of the BCUC, this was certainly the case. The Commission was asked to evaluate the costs and benefits of energy removals without knowledge of the contracts that would comprise them. The Commission was asked to make recommendations on the use of Burrard prior to the release of B.C. Hydro's extensive Burrard Utilization Study, at a time of changing air emission policies in the GVRD and in the face of rapidly developing environmental science. At the same time, the institutional setting governing energy policy in B.C. is in a state of flux, and approaches to utility resource development and resource dispatch are dramatically changing in response to concerns about environmental impacts and forecasting uncertainty. Some of these transitional issues are summarized below.

1.4.1 Institutional and Policy Changes in B.C.

The institutions and policies affecting energy in British Columbia are in a period of significant change. This process, which began prior to the change of government, has intensified with some initiatives of the new government.

An Energy Council is being created. The mandate of this advisory body is to involve the public in long term energy issues. These include long term demand and supply planning, but also specific policy questions, such as the acceptability of long-term exports.

A provincial environmental impact assessment process is being developed by the Ministry of Environment. It may supercede some of the energy project review responsibilities of the Ministry of Energy, Mines and Petroleum Resources ("Ministry of Energy").

The GVRD is engaged in an extensive process of research, public involvement, and regulatory policy development in order to achieve Lower Mainland air quality targets. The GVRD has responsibility for regulating air emissions point sources, such as Burrard. Permitted emission standards are to become more stringent as the GVRD pursues its objective of dramatically reducing NO_X emissions.

Initiatives to encourage private electricity production have met with a strong response. This initiative is a dramatic departure from the policy of the last 30 years, and it will require clear procedures for resource competition and acquisition, cost allocation and regulation, environmental assessment and coordinated resource planning. Most of these procedures are still under development.

The Canada-U.S. Free Trade Agreement ("FTA") has created new opportunities for electricity trade. However, there are still significant political, economic and technical issues to be resolved, some of which may impact the conditions attached to energy removals.

1.4.2 Incorporating the Environment in Dispatch Decisions

The last 10 years have seen a revolution in methods used by electric utilities to evaluate their resource options. With "integrated least cost planning", an approach which originated among utilities and utility commissions in the U.S., utilities look at all resource options on both the supply and demand side for satisfying increases in the demand for electricity services. The options are evaluated not just in terms of their financial costs and benefits, but also in terms of their environmental (and at times social) costs and benefits.

Until recently, this concern for incorporating environmental considerations into resource planning was restricted to new investments. The operation of existing electricity generating facilities is still primarily governed by short-term financial considerations. In other words, in deciding whether to operate (dispatch) a facility, the utility looks at the incremental financial costs and benefits of producing extra electricity from a given plant. This sequencing of plant dispatch takes no account of differences in the environmental operating costs of different facilities.

Utilities and utility commissions have not yet developed norms and procedures for estimating and incorporating the incremental dispatch costs of different types of electricity generating facilities, but this is an area in which methodology and practice are developing rapidly.[2] However, the Terms of Reference for this hearing address this very question, by posing the challenge of estimating the value of the incremental environmental costs of dispatching for export not just the Burrard plant, but each facility in the B.C. Hydro system.

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2 See Chapter 7.0 discussion of abatement cost and damage cost for estimating incremental environmental effects.

1.4.3 The Changing Time-Frame of Resource Planning

In the 1970s and early 1980s electric utilities became aware of how vulnerable they were to dramatic and unforeseen changes in the growth of electricity demand. This vulnerability was the result of at least two factors.

(i) Demand was traditionally perceived as a black box, outside the control of the utility. It was assumed that the only response was to develop better methods of demand forecasting.

(ii) Large projects were perceived as the lowest cost investments. The projects took years to complete and added large increments of electricity capacity, thus requiring accurate demand forecasting into the distant future (at least 5 to 10 years).

This vulnerability to uncertainty of demand manifested itself in the early 1980s, when many utilities in North America found themselves with large unneeded projects either just recently completed or only partially completed.

In response, the 1980s witnessed a change in utility thinking, a change in which uncertainty was more explicitly incorporated into utility resource planning. Now, in the 1990s, utilities are beginning to consider all or part of at least two strategies to deal with uncertainty.

(i) Demand evolution is no longer seen as totally outside the utility's control. Thus, demand-side management programs allow the utility to dampen the load growth effects of dramatic changes in population, economic activity or other external factors, thereby reducing the uncertainty.

(ii) It is now recognized that cost minimization should not be the only factor determining resource selection. Investment risk reduction is also important. Inclusion of this factor will improve the attractiveness of resources that can be brought more quickly through all the stages of design, approval and construction, thereby reducing risk exposure to demand uncertainty.

The net effect of these efforts to reduce uncertainty is to reduce the planning horizon of the utility. There is still a value in long-run (circa 20 years) forecasts, because these encourage utilities, utility commissions and utility customers to assess the desirability of the likely long-run resource development trajectory. However, the utility's planning horizon is shortened to the extent that decisions to commit some resources (investment decisions) need be taken only three to six years in advance of need. This reduces vulnerability to uncertainty, and also changes the traditional assumptions about definition of the time frame for short-term and long-term decision making, one of the key concerns of this report.

1.5 The Nature of British Columbia's Electricity Trade

The term "electricity trade" refers to the sale, purchase or exchange of electricity involving the coordination of resources and operations among interconnected utilities and other electricity suppliers. Electricity trade between British Columbia and the U.S. is conducted primarily by B.C. Hydro and its subsidiary, POWEREX. Modest amounts of trade (essentially interruptible sales) have been undertaken by West Kootenay Power Ltd. ("WKP") and Cominco Ltd.

The B.C. Hydro electrical system supplies some 90 percent of the Province's population, mostly by means of hydroelectric generating plants located throughout the province and linked together by an interconnected system of transmission lines rated as high as 500,000 volts. Figure 1 shows the location of the major hydroelectric generating plants and transmission lines.

There is a significant potential market for British Columbia's relatively inexpensive hydroelectric surpluses, as these can readily displace more costly thermal generation in the U.S. Additionally, differences in the timing of electricity demands within the market area can mean that one system needs electricity when another may have surplus available. The importance of electricity export trade to British Columbia is illustrated in Figure 2.

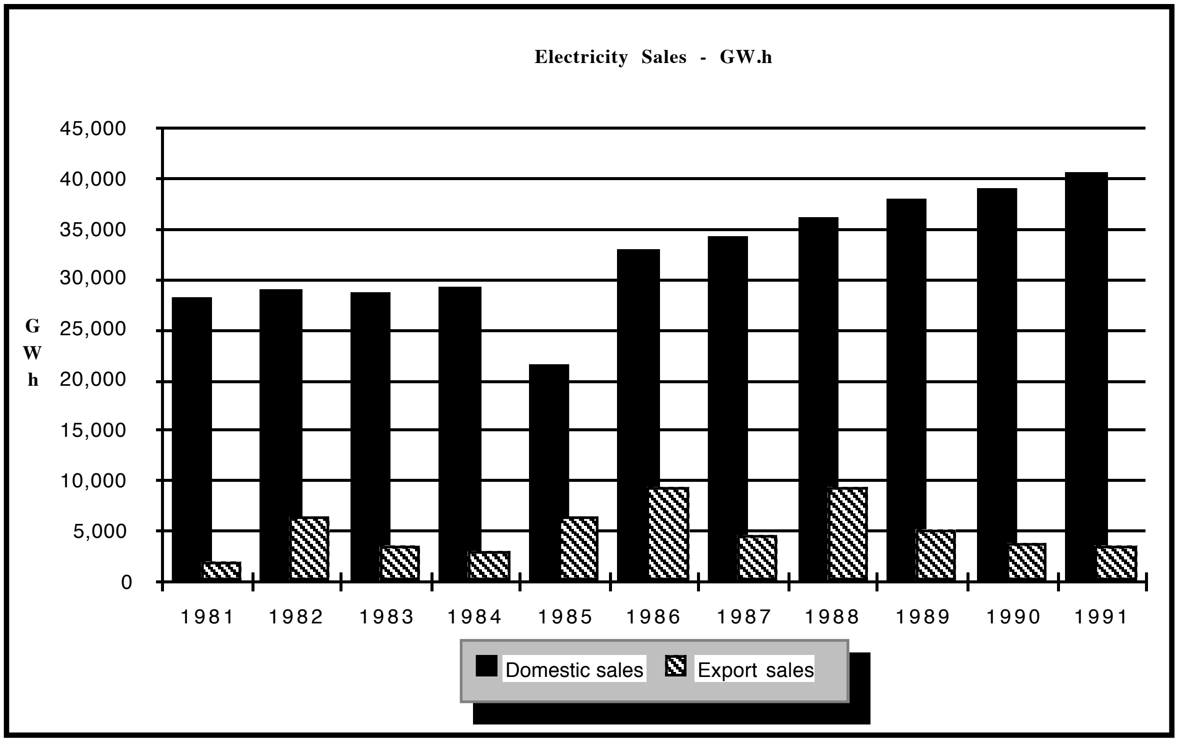
1.5.1 <u>Electricity Sales to the U.S.</u>

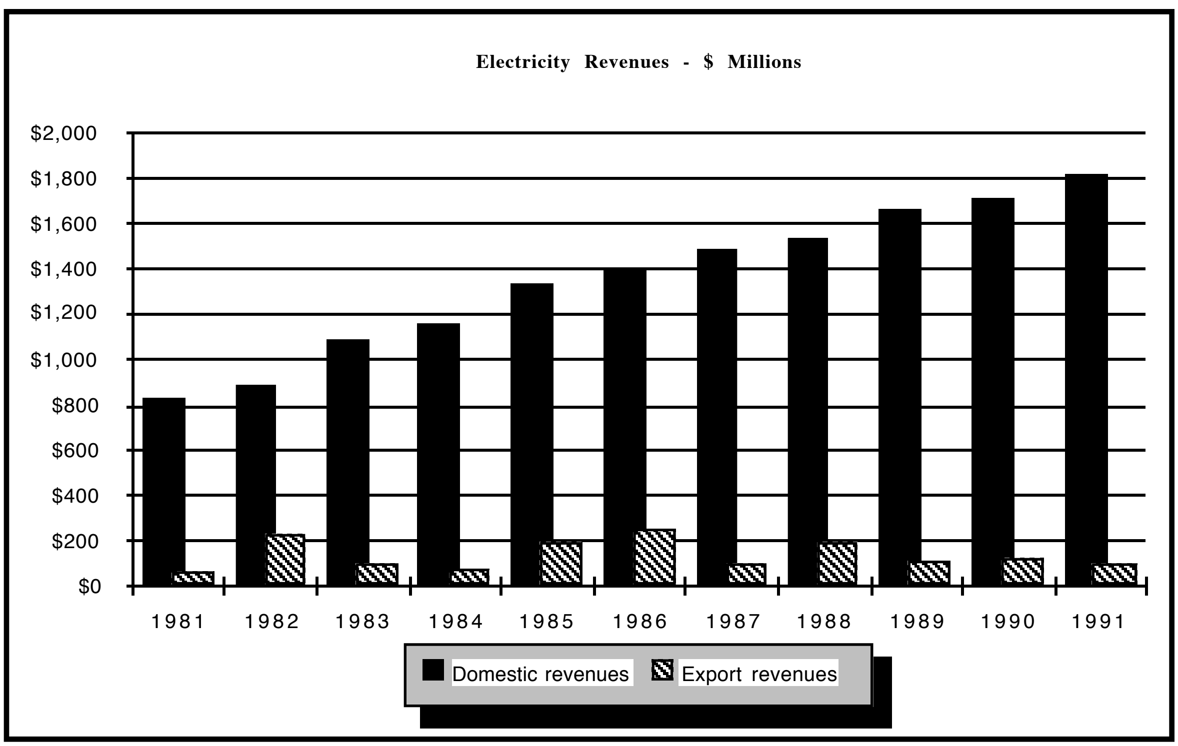
Power and energy sales to the U.S. are undertaken on either a firm or interruptible basis. The potential for firm sales is based on the Applicants' determination of the firm surplus capability of the B.C. Hydro system. Consequently, firm sales may be contemplated when the Applicants are reasonably confident that the duration of the sale and the quantities to be committed will not jeopardize the security of supply to domestic customers. Such situations will normally arise when the Applicants predict high levels of stream-flows into the major reservoirs, or when significant firm domestic purchases have been secured.

Firm sales attract prices from 0.2 to 1.5 cents/kW.h higher than those for interruptible sales (Exhibit 2, Tab 1, p. 3), therefore the Applicants' marketing strategy is usually to seek firm markets for their firm supplies.

FIGURE 2

ELECTRICITY EXPORTS RELATIVE TO DOMESTIC SALES AND REVENUES





Interruptible sales are normally supplied from the province's hydroelectric resources when reservoir levels and forecast inflows indicate surplus quantities of non-firm energy. Failure to secure such sales would often result in spills. Firm surplus that cannot be marketed on a firm basis, may have to be sold as interruptible whenever there is the possibility of spilling.

1.5.2 Power Purchases from the U.S.

The Applicants sometimes find it economical to engage in the purchase of surplus electricity from the U.S. for use in displacing higher cost resources, to refill system reservoirs when low inflows are projected, or to store in reservoirs for later resale when market prices are higher. Such purchases are normally conducted on a short-term or spot basis.

1.5.3 Power Exchanges[3] and Coordination with the U.S.

By holding membership in the Western Systems Coordinating Council ("WSCC"), which facilitates the execution of coordination agreements, B.C. Hydro has been able to increase the security of supply to its domestic customers. This is manifested in the enhanced reliability afforded by the integrated operation of its system with the interconnected systems in the western U.S. In the provincial context, coordination occurs between the domestic hydroelectric system and predominantly thermal systems in the U.S. Additionally, there are also relatively small transfers of electricity between British Columbia and Alberta or the U.S. for the purpose of adjusting electric energy account balances. These are non-revenue transactions.

Coordination and exchange (or equichange) arrangements are conducted in such a fashion that rarely are there payment transfers between utilities. This is because such transactions are typically arranged to ensure that no significant net supply of electricity to or from the province would result over an operating period of several years.

1.5.4 Storage Arrangements with the U.S.

> "Storage agreements are a general form of coordination in which surplus electricity would be stored in the reservoirs of another utility and later returned when the electricity would be more valuable or usable. B.C. Hydro often stores electricity for U.S. Pacific Northwest utilities which tend to have surplus electricity during May and June when stream-flows are high on the Columbia River system" (Exhibit 26, p. 5).

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3 Power Exchange transactions involving an equal transfer of energy are referred to as *equichange* transactions.
4 Power Exchange transactions involving an equal transfer of energy are referred to as *equichange* transactions.

The electricity is subsequently returned when requested, provided that the timing does not adversely impact on the normal domestic operations of B.C. Hydro. These storage arrangements generally produce no net removal of electricity from the Province.

Storage agreements, such as the B.C. Hydro/Bonneville Power Administration ("BPA") Non-Treaty Storage Agreement, can have significant benefits to B.C. Hydro, both financially and in terms of system operation. The present value of these stream and storage benefits is estimated to exceed $100 million (Exhibit 2, Tab 1, p. 10).

1.5.5 Alberta Trade

Presently there are two 138,000 volt lines and one 500,000 volt line interconnecting the B.C. Hydro system with the TransAlta Utilities Corporation ("TransAlta"), a component of the Alberta Interconnected System. At the time of the ERC Application, the Applicants did not have any firm sales contracts with Alberta. However, an agreement is now in place which permits a firm energy purchase from Alberta for resale to BPA.

Significant potential does exist for hydro/thermal coordination between B.C. Hydro and TransAlta. B.C. Hydro's predominantly hydroelectric resources have the flexibility to provide an inexpensive load factoring function, thereby permitting the predominantly thermal generation Alberta system to be essentially base-loaded, with the Alberta system's peaks and valleys being partially supplied or absorbed by the B.C. Hydro system. This coordination can result in significant cost savings to TransAlta that are shared with B.C. Hydro.

1.5.6 Wheeling for Independent Power Producers (Proposed)

Wheeling, also referred to as a carrier transfer, is the transmission of electric energy generated by one party to another using the transmission system of a third party. Important policy issues with respect to independent power production in the province are yet to be delineated by the present government. Policies are needed to guide the rules for wheeling of Independent Power Producers' ("IPP") power to export markets, including access to B.C. Hydro's transmission links and the level of remuneration for that access.

1.5.7 Emergency Exchanges

An important benefit of an interconnected system is the security and reliability afforded to the interconnected utilities during system emergencies. Such emergencies generally result from the unexpected loss or failure of a major system component. Emergency relief from the interconnected system would often ensure that the affected or stressed utility maintained system stability and uninterrupted service to its customers. Energy taken or provided under emergency conditions is normally handled through an adjustment transfer.

1.5.8 Treaty Commitments and Border Accommodations

(a) Columbia River Treaty

In 1961, Canada and the U.S. signed the Columbia River Treaty ("CRT") to jointly develop the Columbia River system. The CRT provided for construction of three large storage dams in Canada (Mica, Keenleyside and Duncan) and one in the U.S. (Libby). These storage dams added much needed flow control along the entire river and also made it possible to generate more electricity and increase hydroelectric power reliability.

The CRT committed Canada to provide 19 trillion cubic metres (15.5 million acre-feet) of storage for improving the flow of the Columbia River which in turn improved power generation in the U.S. The CRT divided power benefits evenly between Canada and the U.S. Canada sold its share of these benefits (approximately 600 average annual megawatts) to the U.S. for the first 30 years beginning in 1968. The CRT therefore forces some limits on the Applicants' use of the Columbia River reservoirs in maximizing their electricity trade benefits.

(b) Skagit Valley Treaty

The Skagit Valley Agreement (the "Agreement") was executed between the Province of B.C. and the City of Seattle ("Seattle") on March 30, 1984. The Agreement committed B.C. to supplying Seattle for a period of 80 years, a certain amount of electric power and energy, equivalent to the incremental power that Seattle City Light would have generated by the raising of the Ross Dam in Washington State. This dam was planned to be raised some 120 feet which would have flooded parts of the Skagit Valley in B.C. The Agreement also incorporated provisions for the raising of the Seven Mile Dam in B.C. which involved flooding into Washington State.

(c) Border Accommodations

B.C. Hydro supplies power to Point Roberts in Washington State, and Hyder in the State of Alaska. These are two border towns that are more conveniently and economically served from Canada than from the U.S. utilities with responsibility for service to these areas. B.C. Hydro receives revenues for providing such services.

2.0 PUBLIC CONCERNS EXPRESSED AT THE HEARING

Representatives of specific interests, as well as members of the public at large, took many opportunities during the hearing to express their concerns about various aspects of the ERC Application. Specific concerns are presented in the later chapters devoted to individual aspects of the Terms of Reference. This chapter provides an initial overview of these concerns.

2.1 The Term of the ERC

In light of the time that has elapsed since the April 29, 1991 ERC Application, the Applicants have now requested a five-year term[1] for the ERC, thereby maintaining the current September 30, 1997 expiry date. Most intervenors considered a five-year term to be too lengthy, especially because of the lack of information in key areas. Issues of concern included: the incomplete Burrard Utilization Study commissioned by B.C. Hydro; impending changes in provincial and regional air quality management objectives and policies; an impending provincial review of electricity export policy; and, untested implications of the Canada-U.S. FTA. For example, Mr. Donald Scarlett, on behalf of the Kootenay-Okanagan Electric Consumers Association ("ECA"), proposed that a one to two year ERC be considered, as this time-frame "... would enable a better judgement to be made on the impact of Burrard, since B.C. Hydro's (Burrard Utilization) study would finally be available." (Exhibit 167, p. 12).

2.2 Risks to Domestic Security of Supply

Intervenors expressed concern about the risks to domestic security of supply from the contractual commitments of several years that B.C. Hydro would be permitted to make under this ERC. In defence of the ERC length, B.C. Hydro argued that it follows a rigorous provincial procedure for determining surplus firm and interruptible electricity (see Chapter 3.0), and that lengthy contracts would still require ministerial approval. However, intervenors were concerned that contracts to export firm energy, if based on erroneous forecasts of domestic supply and demand, could require B.C. Hydro to purchase electricity from elsewhere, to make excessive use of Burrard or even to advance the construction of planned projects. For example, the Consumers Association of Canada ("CAC") noted the risks to domestic security of supply from a four year export commitment (T.Vol. 2, p. 309). The ECA expressed concern about extended export commitments when water flows and reservoir levels could only be predicted on an annual basis (T.Vol. 4, p. 540). The ECA

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1 The original Application was for a six-year term extending from 1991 to 1997.

also expressed the concern that the ERC would lead to the perception that the savings from energy conservation programs would be diverted to the export market (T.Vol. 4, p. 573).

2.3 The Need to Fully Account for Environmental Externalities in Export Pricing

Most intervenors expressed the opinion that all environmental costs of electricity generation for export should be included in the price of exports. The Applicants pointed out the difficulty with quantifying, especially in monetary terms, environmental costs. Moreover, they argued that environmental costs are largely already incorporated in the cost of production because of operating restrictions on hydroelectric facilities and pollution permits required for running Burrard. Many intervenors countered that there are obvious and substantial additional environmental impacts, and that at least some estimate in terms of price would be preferable to no accounting at all. The general view was that failure to account for environmental effects in export sales minimized the true cost of exports. Whether the concerns related to air quality problems in the Fraser Valley or wildlife and recreational effects from hydroelectric facilities, there was strong support for the position that the costs associated with the adverse environmental impacts of electricity generation should be recognized in deciding whether exports should be permitted.

At the heart of the debate was disagreement over the extent to which there was reliable scientific evidence to attribute adverse environmental impacts to B.C. Hydro's operations and, specifically, export operations. The view expressed by intervenors was consistent in urging the Commission to act in spite of the scientific uncertainty. For example, the GVRD submitted that, "...if we wait for science and economics to provide definitive answers to each of our pollution control decisions, we're going to be choking on smog in this valley long before we even start to address the problems." (T.Vol. 23, p. 3684).

Further controversy focused on the various techniques that could be used to value the environmental costs of exports; depending on the choice of technique, the estimate of environmental cost can differ tenfold. This controversial subject is discussed further in Chapters 6.0 and 7.0.

2.4 ERC Implications for the Lower Mainland Airshed

The Applicants have included Burrard as an integral part of their generation system in support of exports. First, without Burrard providing critical hydro system backup, there would be no *firm* surplus from the B.C. Hydro system to allow firm export commitments (firm sales would still be possible, if purchased from other sources such as Alberta). Second, while the Applicants noted that most *interruptible* exports would originate from higher than expected water flows, the Burrard plant could also serve the interruptible summer market because of the low cost natural gas available in the summer.

The inclusion of Burrard in the Application was the single most important public concern in the hearing. The concern focused on the air emissions of nitrous oxides resulting from the combustion of natural gas for electricity generation. Nitrous oxides can be a pollution problem themselves, but more importantly they contribute to the downwind production of *ozone* in the Lower Fraser Valley ("LFV"), the predominant air pollution problem associated with urban areas.

Concerns ranged over both the general issues of air pollution from Burrard and the specific implications of the ERC for the level of operation of Burrard.

There was a strong sentiment that the plant is poorly located (T.Vol. 7, p. 914). The area around the plant has some of the worst air quality readings in the LFV. The plume from the plant contributes to the GVRD urban plume of NO_X, VOCs and other compounds that drift eastwards leading to high concentrations of ozone in the central and eastern portions of the LFV. Notably, the greatest public turnout for any one day of the hearing was at the session in Chilliwack. At that session, members of the public and local politicians gave compelling accounts of their concerns for the effects of air pollution on human health, vegetation (resulting agricultural and silvicultural losses), aesthetics (visual degradation), and regional development (loss of appeal of Fraser Valley destinations for tourists and retirees).

The poor location of Burrard led to several different arguments, including:

- the plant should be immediately closed,
- the plant should only be used for emergency backup and ancillary system support,
- the plant should be converted to the cleanest technology available.

These concerns relate to the use of Burrard whether for export or domestic production. However, additional concerns were raised on the role of Burrard in export. To some, the incremental increase in air pollution attributable to using Burrard for export was tantamount to importing U.S. pollution, selling off our health and welfare cheaply (i.e. pricing without costing externalities), and subsidizing U.S. production to the detriment of the agricultural industry in the LFV (T.Vol. 7, pp. 925-963).

Finally, an "open-ended" ERC was seen as opening the door for a much more expanded use of Burrard, especially for summer exports to the U.S. (T.Vol. 7, p. 993).

2.5 Other Environmental Concerns

Numerous concerns were raised regarding the possible adverse environmental impacts associated with the operation of B.C. Hydro's hydroelectric facilities in support of electricity exports.

Concerns about the possible effects of electromagnetic fields ("EMF") led to a request that B.C. Hydro calculate the incremental effect of exports on transmission loads for typical circuits in the Lower Mainland (T.Vol. 15, p. 2095).

The Chief for the Council of the Village of Kitamaat testified that the Council was concerned that the Kemano Completion Project may have detrimental effects on fishery in the Kemano River, which is a valuable resource to the community (T.Vol. 2, p. 248). While B.C. Hydro had originally included electricity from the Kemano Completion Project in its calculations for the ERC, this had been deleted by the time of the hearing.

Some intervenors argued that the attention being given to exports detracted from efforts to conserve energy. SPEC argued "...that the decision of this hearing could mean the choice between conservation and increased generation and export." (T.Vol. 23, p. 3781).

Numerous intervenors raised concerns about the effects that electricity export commitments would have on B.C. Hydro's operation and management of its hydroelectric facilities. The concerns related to the impact that fluctuations in water levels have on the ecosystems and recreational uses of reservoirs and downstream river valleys.

2.6 Exports and the Free Trade Agreement

A number of intervenors raised questions about the applicability of the Canada-U.S. FTA to this ERC. The principal argument was that by granting this ERC the Province may commit itself to continuous provision of electricity to the U.S. This is because there is a provision in the agreement that does not allow restrictions that result in reductions to the proportion of energy available for export to the U.S. Some intervenors argued that in the interest of domestic security of supply, no exports should be permitted until the government was certain that the clause could not be interpreted in a way that would prohibit a reduction in electricity exports resulting from the normal expiry of short-term contractual agreements or in times of greater domestic need.

2.7 Domestic Residential and Commercial Access to Interruptible Electricity

The current plans of the Applicants preclude domestic residential and commercial marketing of interruptible energy. Previously, the Electric Plus Program ("E-Plus") of B.C. Hydro (1986 - 1990) had marketed interruptible electricity in some parts of the province to residential and commercial customers for space and water heating consumption only. SPEC and some other intervenors suggested that the E-Plus program might have been prematurely withdrawn and that the entire customer base should be afforded an opportunity to acquire surplus (exportable) power (T.Vol. 23, p. 3785).

2.8 Fair Market Access to Exported Electricity

The Terms of Reference for this hearing asked the Commission to review the mechanism whereby electricity proposed for export is first offered to domestic interconnected utilities. The Applicants have proposed that the current mechanism be changed. For exchanges (including exports) of less than one year, all buyers and sellers would have equal opportunity to bid in a competitive PEO. For longer term contracts, domestic interconnected utilities would be required to approach the Applicants with offers to purchase, but would have no right to intercept negotiated contracts.

Mr. Robert Hobbs, intervening for WKP, argued that the Applicants' proposals would lead to a reduction in security of supply and potentially higher costs for domestic utilities, and thereby for domestic customers (T.Vol. 9, p. 1198).

2.9 The Nature of the POWEREX/B.C. Hydro Relationship and the Power Exchange Operation

The ECA questioned why B.C. Hydro was applying to the provincial government (via an Energy Project Certificate Application) to utilize the PEO even for its sales to domestic customers (T.Vol. 3, p. 427). The Applicants responded that it would be the appropriate way to run a spot market, where prices are market based. The ECA was also concerned about the apparent lack of public scrutiny of the operations of the PEO.

3.0 DEFINITION OF SHORT-TERM, DETERMINATION OF SHORT-TERM SURPLUS, DOMESTIC RELIABILITY AND SECURITY OF SUPPLY

3.1 Background

3.1.1 Terms of Reference 2, 3 and 4

Terms of Reference 2, 3 and 4 address issues which, because they are closely related, are combined in this chapter. These three Terms of Reference are restated below.

> "2. The Commission shall review the Application to ensure that reliability and security of electricity supply to British Columbians will not be adversely affected by the proposed removals. Without limiting the generality of the foregoing, the Commission shall also review any written agreements submitted to the Minister by the Applicants or either of them, pursuant to Condition 9 of ERC 80(8403) as amended, prior to the conclusion of this review.
>
> 3. The Commission shall review and assess the current provincial procedures for determining B.C. Hydro's removable short-term surplus, as outlined in the "Reasons for Decision" for ERC 80(8403) and "ERC 80(8403)", as amended, which are attached hereto and form part hereof, in view of the changes which have occurred and are expected in the resource mix available to B.C. Hydro, including demand reduction programs and purchases from other electricity producers.
>
> 4. The Commission shall review the issue of the time-frame which should be considered *short-term* for the purpose of the Application."

Terms of Reference 3 and 4 are connected because the definition of the "short-term time-frame" (Term of Reference 4) is required prior to assessing the procedures for determining the *short-term removable surplus* (Term of Reference 3). Similarly, a determination of the short-term removable surplus (Term of Reference 3) may be required prior to assessing the affect of the proposed removals on *domestic reliability and security of electricity supply* (Term of Reference 2). Thus, the logical sequence followed in this chapter is to deal with these three terms of reference in reverse order.

In combination, these three terms of reference seek an evaluation of the Applicants' definition of short-term and claim of a short-term removable surplus, and the Applicants' claim that the time period and quantities applied for in this ERC will have no adverse effects on reliability or security of supply to B.C. Hydro's domestic customers. However, it should be noted that the three interconnected issues outlined below constrain the Commission's ability to clearly fulfill its mandate with respect to these three Terms of Reference.

3.1.2 Constraints to Satisfying Terms of Reference 2, 3 and 4

First, the ERC Application is for *upper limits* for annual removals of:

- firm power (2,300 MW to U.S. and 1,200 MW to Alberta),
- firm energy (6,000 GW.h), and
- interruptible energy (25,000 GW.h less concurrent firm).

The upper limit for firm power is based on B.C.'s transmission intertie capacity with the U.S. and Alberta.[1] The upper limit for firm energy is based on potential firm surplus energy from B.C. Hydro, Alberta utilities and other possible electricity suppliers. The upper limit for interruptible energy is based on a possible maximum combination of (i) high *flow through* of Alberta energy, (ii) high coincident removals due to storage, exchange[2] and coordination agreements, and (iii) high net exports to the U.S. because of lower than anticipated domestic demand and/or high B.C. Hydro water flow conditions (Exhibit II, Tab 2, p. 8 of 11). Because these upper limits are contingent upon future conditions, the Applicants can justifiably claim that if these conditions do not materialize, then the removals will be less. Specifically, the Applicants claim that no removals would be undertaken that decreased existing standards of domestic reliability and security of supply. Thus, the upper limits applied for in the ERC do not by themselves guide the Commission in assessing the effect of the ERC on reliability and security of supply.

Second, there is thus far only one signed contract covering the period of the ERC. This is a three year firm energy sale (to July 31, 1995) to BPA for 876 GW.h annually at prices from 2.4 to 3.1 cents/kW.h. Some information about a second, unexecuted contract was also made available. This was a proposed four year firm energy sale to Portland General Electric for about 1000 GW.h annually (the price was not specified). Together, this sale and proposed sale comprise only a portion of the quantities listed in the ERC Application. This severely limits the Commission's ability to evaluate the ERC's impact on domestic reliability and security of supply.[3]

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1 This includes 300 MW of intertie capacity owned by Cominco, but available to B.C. Hydro and POWEREX.

2 Energy that would be returned at another time, resulting in no net removal but potentially necessitating considerable one-way flow in any given year.

3 This also affects the Commission's ability to evaluate net benefits; see Chapter 7.

Third, potentially important contributors to the Applicants' U.S.-bound electricity exports are Alberta electric utilities. The Applicants claim that up to 4000 GW.h of firm energy are potentially available from Alberta from off-peak electricity generation.[4] Thus, even if an analysis of B.C. Hydro's forecast surplus and ERC contract commitments suggested a threat to domestic reliability and security of supply, the Applicants could maintain that increased Alberta imports will ensure that domestic standards are not compromised. Ultimately, this implies that the Commission should review the reliability and security of supply of electricity from the Alberta system. The Commission believes that such a review goes beyond the intent of the Terms of Reference of this hearing.

The net effect of these three constraints is that the Commission is restricted in its effort to definitively address Terms of Reference 2, 3 and 4. However, as this chapter will show, there are several key issues that the Commission wishes to address. These involve (i) critically evaluating the Applicants' definition of short-term, (ii) assessing the removable surplus from B.C. Hydro's system in isolation and (iii) assessing the implications of including other supply systems in the ERC analysis.

3.1.3 The ERC and the Role of POWEREX

While the role of POWEREX may soon be redefined by the government, the Commission had to rely on existing documents to assess the mandate of POWEREX. The Operational Review of October, 1989 to September, 1990 states that POWEREX was established by the B.C. Government:

> "to be a single window agency responsible for implementing the Provincial policy of international electricity trade." (Exhibit 78, p. 1)

Thus, the assumption of the Commission in this report is that POWEREX will serve as the sole agency for firm electricity exports from B.C., including the flow-through of electricity from Alberta to the U.S.[5]

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4 A letter from TransAlta Utilities to B.C. Hydro on January 3, 1992 estimates the firm surplus energy from the Alberta interconnected system at 3,700 to 4,100 GW.h during the 1992 to 1995 period (Exhibit 3, GVRD, Ques. 6, p. 2 of 2). Electricity purchases from Alberta are the source for all of the 876 GW.h per year supplied by B.C. Hydro in its recent three-year sale to Bonneville Power Authority (1992 to 1995) (Exhibit 31, Contract of March 30, 1992).

5 See Chapter 4.0.

The Commission therefore assumes that the Minister is in agreement that POWEREX and B.C. Hydro should be awarded access to most or all of B.C.'s transmission interties with external agencies if this Application is approved. However, nothing precludes the Minister from granting ERCs in the future to other parties, in concert with a mechanism for allocating the total capacity among competing claimants.[6]

3.2 Definition of the Short-Term Time-Frame: Determining B.C. Hydro's Short-Term Removable Surplus

3.2.1 Assessing the Applicants' Definition of Short-Term for the ERC and for Determining the Short-Term Removable Surplus

In evidence and testimony, the Applicants defined short-term capacity and energy as:

> "... capacity and energy from investments which already exist or which are already committed" (T.Vol. 11, p. 1567).

In the above quote, an example of a committed investment would be a signed contract in which B.C. Hydro promises to purchase electricity from an independent power producer ("IPP") at some future time. By this definition, therefore, the Commission accepts that a short-term energy or capacity surplus is a quantity of energy or capacity that is *unavoidably* surplus to domestic requirements.

In determining the time-frame for the short-term, the Applicants made a distinction between *short-term surplus* and the *appropriate period for the ERC*. Essentially, the argument is that the ERC, by setting upper limits to short-term exports, would cover a period of time in which several individual short-term export contracts would be executed under a coherent set of regulatory and policy guidelines. As such, the Applicants argued that the length of the ERC should be determined by the time period that is reasonable before requiring another regulatory review.

> "... we're seeking a term of six years which we feel is a reasonable period of time to review policy issues relating to issues on electricity trade." (T.Vol. 1, p. 146)[7]

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6 This mechanism could have similarities to the one year PEO discussed in Chapter 4.

7 The Applicants also presented the six year time period as the minimum period of time required to expand the transmission system (Exhibit V, BCUC 5.1, p. 2 of 2).

Thus, the proposed six-year ERC (since reduced to five because of delays) could encompass several short-term contracts. The length of these should be governed by the removable surplus (firm and interruptible) that can be anticipated for resources built to meet domestic firm requirements.

> "B.C. Hydro plans our resource additions to meet domestic firm requirements. Short-term electricity trade is that power which can become surplus from time to time from those same firm resources." (T.Vol. 1, p.145).

> "Short-term exports would be ones from the existing and committed system, and in most situations, we would see that type of export being about four years in length." (T.Vol. 12, p.1674).

The Commission finds that the requested term of the ERC, until September 30, 1997, is a reasonable time period but emphasizes that this time-frame should not be confused with the definition of short-term as it relates to energy exports, and with other time-frames within the ERC. The definition of the short-term time period, as requested by Term of Reference 4, hinges on a precise determination of whether or not a resource is built *justifiably* to meet domestic demand. The Applicants claimed that all B.C. Hydro resources have been built exclusively to serve the domestic market, and that:

> "... long-term energy removal means removals resulting from planning to build resources for the express purpose of exporting the power generated from that resource." (T.Vol. 1, p. 48)

However, while long-term resources could result from building exclusively to serve export markets, they could also result from building projects in advance of domestic need. In testimony, the Applicants agreed with this.

> "... I would see a long-term firm type of agreement as being one in which we deliberately either built a project for export or one in which projects were advanced to permit that export." (T.Vol. 12, p. 1673)

In this ERC, the Applicants are applying only for the right to export short-term surpluses. A project that is *unnecessarily* slated to come into service in advance of forecast domestic needs should be defined as a long-term investment for export, and should be excluded from this ERC and from the calculation of B.C. Hydro's short-term removable surplus.

This issue requires elaboration of the characteristics that determine whether or not an investment included in B.C. Hydro's supply demand balance is *avoidable*. Generally, resources that B.C. Hydro has not yet committed to are long-term resources. These include both resources that would belong to B.C. Hydro and resources owned by others, such as IPPs. However, there can be situations in which a resource which B.C. Hydro has not yet committed to should still be treated as if it were an unavoidable investment, hence potentially contributing to short-term surplus. This is explained below.

There may be resources which B.C. Hydro has not yet committed to, but which must be acquired at a time over which the utility has no control. These are referred to by the Northwest Power Planning Council as *lost opportunity resources*. One example would be a demand-side management program to better insulate new houses and commercial buildings. The timing of this resource is determined by the pace of building construction. If B.C. Hydro does not acquire the resource at the time of construction, it may be too expensive or physically impossible to capture later on. Another example would be a modernization investment at a pulp mill which has potential for increased self-generation of electricity. B.C. Hydro has no control over the timing of the modernization investment, but again it must act to ensure the economically optimal self-generation investment at the time of plant modernization. Investments, such as the two described above, may legitimately be considered part of an unavoidable surplus, referred to here as a short-term surplus.[8]

3.2.2 The Commission's Determination of Short-Term Removable Surplus: Assessing the Provincial Procedures

Term of Reference 3 asks the Commission to review and assess the provincial procedures for determining B.C. Hydro's removable short-term surplus. These procedures are outlined in the Reasons for Decision for ERC-80 (8403), March 19, 1984.

For removable firm energy surplus, the procedure states:

> "B.C. Hydro's removable firm energy surplus is defined to be the difference between the demand for, and the supply of energy from hydroelectric facilities under critical water over the term of an application to remove electricity." (Ministry of Energy, ERC-80 (8403), Reasons for Decision).[9]

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8 An even more complicated example would be a government directive that required B.C. Hydro to purchase all wood waste generated electricity in order to foster the environmental objective of reducing wood waste disposal in beehive burners. B.C. Hydro could legitimately argue that purchase of this electricity was unavoidable, although it would be avoidable from a provincial perspective.

9 The *critical water level* is the lowest recorded four year sequence, that being from 1942 to 1946.

For removable firm capacity surplus, the provincial procedure is described in testimony as:

> "The dependable capacity surplus is calculated by subtracting the forecast peak demand requirements of the B.C. Hydro domestic customers and the required reserve from the dependable capacity of the generation system. We then do a further check to ensure that there are no transmission constraints that would limit the ability to bring that generation to the load." (T.Vol. 1, p. 140)

Interruptible surplus is simply the energy and capacity that is available because of water flow conditions above the critical level.

The Reasons for Decision also states that:

- removals are from *existing* hydroelectric facilities,
- Burrard is *excluded* from the surplus calculation,
- purchases of energy are excluded from the surplus calculation,
- the calculation should be based in part on forecasts prepared by the Ministry of Energy.

In this ERC Application, the Applicants apply these provincial procedures for determining removable surpluses, but make the following changes (Exhibit II, Tab 2, p. 3 of 11).

- Burrard is included, as permitted by Amending Order #2 in 1987,[10]
- the forecast firm energy and capacity contribution of demand-side management programs is included in supply,
- electricity purchases are included,
- the demand forecast is based on B.C. Hydro's current projections, not those of the Ministry of Energy.

Generally, there are sound arguments for these modifications made by B.C. Hydro to the provincial procedures. However, while the Commission accepts the argument that *take or pay* purchase commitments with B.C. IPPs be included in domestic supply, the Commission suggests caution in the treatment of purchase opportunities from outside the B.C. Hydro service area. In particular, B.C. Hydro has not demonstrated to the Commission that the estimated 4000 GW.h. of firm energy from Alberta is reliable. This would require either (i) a binding contractual commitment, or

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[10] ERC-80 (8403 as amended).

(ii) an analysis of the future Alberta supply demand balance comparable to that which has been carried out for B.C.

The Commission finds acceptable the provincial procedures (as modified by B.C. Hydro) for determining the short-term removable firm energy and capacity surplus, with the exception that purchases from outside the B.C. Hydro service area not to be included unless they are clearly demonstrated to be as reliable as other B.C. Hydro sources.

The Commission is not satisfied that B.C. Hydro's analysis, filed in response to BCUC Information Request 3.1, provides an accurate estimate of the removable short-term firm energy surplus, given the Applicants' definitions of short-term and long-term. The procedures for determining the firm removable electricity surplus should ensure that none of the surplus is due to investments that are, in fact, avoidable. If they are avoidable, they should be defined as long-term investments.

Therefore, the Commission recommends that determination of the firm short-term (unavoidable) surplus of the B.C. Hydro system should require the following steps:

(i) each firm resource listed in B.C. Hydro's supply demand balance for the period of the ERC be examined to determine if it is an avoidable or unavoidable investment,

(ii) avoidable investments be subtracted from the firm supply,

(iii) the supply demand balance be recalculated to determine the surplus consistent with the provincial procedures, as modified by the Applicants.

The Commission also notes that the time period in which B.C. Hydro's system switches from unavoidable firm surplus to deficit is an approximate indication of the maximum time-frame for defining short-term. Firm surpluses in subsequent periods are long-term surpluses because they are the result of investments that the utility need not undertake.

The Commission recommends that the time period for defining short-term be determined by the procedure for determining removable firm surplus, modified by the deletion of all avoidable investments. Thus, the time required before the supply demand balance switches from unavoidable surplus to deficit is an approximate indication of the maximum length of the short-term time frame.

3.3 Recalculating B.C. Hydro's Removable Surplus: Implications for Domestic Reliability and Security of Supply

3.3.1 <u>Short-Term Time-frame and Removable Firm Surplus</u>

Following the above recommendation by the Commission, it is possible to re-estimate short-term *firm* surplus from the evidence presented by the Applicants in response to BCUC Information Request 3.1 and from cross-examination of the Applicants' policy panel, and to consequently determine the time-frame for short-term. The following analysis focuses on the short-term *firm energy* surplus from the B.C. Hydro system and ignores determination of capacity surpluses and interruptible energy surpluses. There are several reasons for this.

First, the Applicants stated in testimony that there is limited surplus capacity available for export from the B.C. Hydro system (T.Vol. 8, p. 1153). Second, interruptible energy surpluses are almost entirely the result of variations in water flows, and it is therefore possible to estimate a wide range of interruptible surplus energy. Third, the estimation of firm energy surplus is a key factor for other terms of reference of this hearing, notably, determination of the short-term time-frame; assessment of the effect of exports on security and reliability of service; and, net benefits of exports for the Province and the Applicants.

The perceived mix of resource options available to B.C. Hydro has increased dramatically in recent years. Many of these are smaller resources, with shorter lead times for development. The resource options considered by B.C. Hydro (for its integrated grid) are divided into the following categories: existing hydro system; existing thermal system; purchases from other utilities; demand-side management; self-generation; Resource Smart, and independent power producers. (Some of these are described in the Glossary).

In the following analysis, the first two are held constant; this is because B.C. Hydro's existing hydro and thermal facilities are already completed investments. Purchases from other utilities are omitted because the Commission was unable to critically evaluate the surpluses claimed from these sources. Thus, an interim solution is to assess the B.C. Hydro system in isolation.[11]

B.C. Hydro's filed answer to BCUC Information Request 3.1 presented an estimate of the projected firm short-term energy surplus over the five remaining years of the six year ERC. The *firm* output of the hydro system over the period 1992/93 to 1996/97 is based on the recurrence of the low water flows similar to those recorded in the period 1942/43 to 1946/47. The annual output of Burrard is set at 5270 GW.h,[12] the amount that B.C. Hydro defines as dependable for the given gas supply contracts and other conditions of plant operation.

Table 3.1 presents the results from B.C. Hydro's estimate of its short-term firm energy surplus. This table shows the B.C. Hydro system as having a significant firm surplus of at least 1400 GW.h in all but the last year of the ERC.

TABLE 3.1

B.C. HYDRO FIRM ELECTRICITY BALANCE: 92/93 - 96/97
CRITICAL WATER CONDITIONS (GW.h)
B.C. HYDRO'S EVALUATION (Exhibit 5, BCUC 3.1, p.3)

	1992/1993	1993/1994	1994/1995	1995/1996	1996/1997
DEMAND	47,977	49,172	50,525	51,828	52,808
HYDRO	42,247	41,829	43,247	42,132	40,661
DSM	441	737	1,076	1,428	1,720
S-GEN	0	0	0	1,700	1,700
RS	490	620	710	800	960
ALCAN	670	670	169	0	0
IPP	301	1,544	1,930	2,321	2,527
BURRARD	5,270	5,270	5,270	5,270	5,270
FIRM SURPLUS	1,442	1,498	1,877	1,823	30

LEGEND:

DSM = Demand-Side Management
S-GEN = Self Generation
RS = Resource Smart
IPP = Independent Power Producers

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11 If future firm contracts under the ERC are heavily dependent on external sources (notably from Alberta) the Minister is advised to carefully evaluate these sources to determine the risks to B.C. Hydro's customers in terms of reliability and security of supply.

12 This figure will be reduced by any emission caps applied to Burrard.

Table 3.2 presents the results for the same conditions as Table 3.1, except that all uncommitted (avoidable) investments are subtracted from the domestic supply and demand resources. In other words, this is an attempt to accurately apply the provincial procedures for determining short-term removable surplus under the definition that only unavoidable investments (in the extended sense) are short-term investments.[13]

With these alterations, the domestic firm surplus of Table 3.1 is eliminated at least one year sooner in Table 3.2., becoming a deficit in 1995/96. This shortening time-frame is because the B.C. Hydro removable firm energy surplus calculated in response to BCUC Information Request 3.1 is in part due to the inappropriate inclusion of resources which conform to the Applicants' definition of long-term in that they are avoidable and are not required to meet domestic requirements. The unavoidable surplus disappears within at most three years. This implies that the time-frame for the cross-over from short-term to long-term is no more than three years.

> **The Commission recommends that the Applicants' short-term time-frame, as it relates to the duration of contracts for firm energy, be defined as no more than a maximum of three years. Firm energy sales contracts longer than three years in duration should be referred to as long-term contracts because they will generally require additional investment commitments. Export contracts for firm capacity or energy in excess of three years should not be permitted under this ERC.**

In the future, only rare circumstances would justify lengthening the three-year limit for defining short-term. One example is a situation in which many *lost opportunity resources* became available at the same time, say during a simultaneous modernization of several pulp and paper mills. Another example is the decision that the utility, or an IPP, would construct a very large project, required for domestic needs but destined to not be fully utilized for several years after completion.

The selection of three years as the short-term time-frame also has important implications for an evaluation of the net benefits from electricity exports. If avoidable electricity-producing investments are included in the export surplus calculation, they should be costed in terms of their

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13 The estimates for demand-side management and resource smart are speculative, based on testimony of the B.C. Hydro policy panel. However, the general results are not sensitive to changes in these two estimates.

TABLE 3.2

B.C. HYDRO FIRM ELECTRICITY BALANCE: 92/93 - 96/97
CRITICAL WATER CONDITIONS (GW.h)
NEW COMMISSION CALCULATION OF SHORT-TERM FIRM

	1992/1993	1993/1994	1994/1995	1995/1996	1996/1997
DEMAND	47,977	49,172	50,525	51,828	52,808
HYDRO	42,247	41,829	43,247	42,132	40,661
DSM	331	553	807	1,071	1,290
S-GEN	0	0	0	0	0
RS	368	465	533	600	720
ALCAN	670	670	169	0	0
IPP	301	1,220	1,440	1,440	1,440
BURRARD	5,270	5,270	5,270	5,270	5,270
FIRM SURPLUS	1,209	835	941	-1,315	-3,427

NOTES:

(i) The demand-side management savings have been reduced by 25 percent from the estimates in shown in BCUC Information Request 4.1 (see Exhibit 5). This change is driven by the assumption that at least some of the demand-side management programs, such as efficient electric motors, can be slowed down in times of surplus, as suggested by the Northwest Power Planning Council, and agreed to by B.C. Hydro in cross-examination (T.Vol. 11, p. 1560-1567).

(ii) The new self-generation of 1700 GW.h starting in 1995/96 is reduced to zero. The Applicants testified that no contract has been signed and it is not apparent that the contracts under consideration would be *lost opportunity resources* if not captured in the time-frame of the ERC (T.Vol. 11, p. 1559).

(iii) The resource smart program has been reduced by 25 percent from the estimates in BCUC Information Request 4.1. The Applicants testified that some of the resource smart programs, such as turbine upgrades, could be slowed down at little or no cost (T.Vol. 11, pps. 1549-1554).

(iv) The independent power production has been reduced to those projects to which B.C. Hydro has already made contractual commitments. Start-up times could be delayed for projects to which B.C. Hydro is not yet firmly committed (T.Vol. 11, pp. 1554-1558; Vol. 12, pp. 1719-1722).[14]

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14 Up to 1993, it is assumed that the McMahon natural gas plant and the North West Energy wood waste plant will annually generate 1220 GW.h. By 1995, it is assumed that the addition of the Mamquam hydro project will bring this annual total to 1440 GW.h.

full life cycle cost. Making this correction has the effect of lowering net benefits below those calculated by the Applicants. This issue is discussed in Chapter 7.0.

It is also notable that B.C. Hydro's short-term firm surpluses over the next few years depend upon the availability of Burrard for its total firm capability of 5270 GW.h. Chapter 6.0 presents a proposal to reduce the annual capability of Burrard via summer restrictions. If for this, or any other reason, Burrard is not able to count the full 5270 GW.h as firm, there may be no short-term firm surplus in the B.C. Hydro system, even in the early years of the ERC.

3.3.2 Innovations in Flexible Resource Planning

The analysis in Table 3.1 and Table 3.2 illustrates the implications of a recent development in electric utility resource planning, especially with respect to dealing with uncertainty. In the past, utilities were especially vulnerable to demand uncertainty because electricity generation projects required a minimum of five years to approve and construct. Since these projects added large increments to the system, a period of surplus would follow completion. However, thanks to the steady growth of electricity demand in the post war decades, the period of surplus was not long, and vulnerability to demand uncertainty remained hidden.

This vulnerability only became apparent in the early 1980s, when dramatic demand fluctuations left many North American utilities stranded with new or partially completed plants, surplus to demand. In response, utility planners have come to recognize that smaller plants, with shorter time-frames from approval through to completion, represent one way to reduce vulnerability to demand uncertainty. Smaller plants, and other incremental investments such as those of B.C. Hydro's Resource Smart, can be undertaken by the utility, by its customers (self-generation), or by independent power producers. A further step, advocated by the Northwest Power Planning Council, is for utilities to advance projects through the approval process to the *shelf-ready stage* in advance of actual need.[15]

In concert with this *flexible resources* approach to reducing the vulnerability to demand uncertainty, has been a recognition that utilities also have some control over the pace of demand growth through their demand-side management programs. Some programs can be accelerated or retarded in

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15 Shelf-ready means that the project has already been designed and passed all major siting requirements, such as environmental and technical approval.

response to changing estimates of the supply demand balance. As stated by B.C. Hydro's policy witness,

> "... there are programs ... that can be turned on in a very accurate way. ... motors in industry, for example, those can be precisely timed to a much better degree than some of the energy savings that come from a new ethic ..." (T.Vol. 11, p. 1566)

These new approaches to resource planning suggest that utilities should become better able to balance supply and demand by including in their mix of options flexible resources that can be quickly brought on line. B.C. Hydro claims that it is heading in this direction.

> "... I've asked our people to specifically look at projects that can be started during the critical period. ... to make better use of the storage capability that we have without holding energy in reserve for the fourth year of the critical period." (T.Vol. 11, p. 1558)

Indeed, this new approach to flexible planning may be particularly worthwhile for B.C. Hydro because of the flexibility already offered by a hydro system with substantial storage capacity.

> " ... that's one of the reasons why we've gone to these smaller projects, because they appear to take a much more compressed time-frame than the larger ones. As far as potential deferrals, I don't think that should be necessarily a cause for concern as far as ending up with a deficit ... because there is shaping capability in our Hydro system, and we can readjust the Hydro system operation to cover any short-term deferrals," (T.Vol. 12, p. 1721).

These elements of flexible resource planning have important implications for the determination of the short-term time-frame, one of the Terms of Reference of this report. In general, their net effect is to shorten the planning horizon and the definition of the short-term time-frame. However, this only occurs if the utility is actively exploring cost-effective options for reducing its vulnerability to uncertainty. B.C. Hydro's witnesses suggested that the utility is moving in this direction, but explicit actions are desirable.

> **The Commission recommends that B.C. Hydro be directed to thoroughly explore innovative mechanisms of reducing uncertainty in matching domestic supply and demand. This should include categorizing demand-side management programs into those that are more and less flexible, and integrating the flexible programs into the demand supply balancing process. It should also include developing a process in which quick response resources are brought to the shelf-ready stage. All of these mechanisms should be evaluated for cost-effectiveness; i.e., the benefits of**

reducing uncertainty should exceed the costs. The net effect of these mechanisms should be to redefine the short-term time-frame for the purposes of determining the unavoidable removable electricity surplus.

3.3.3 B.C. Hydro's Domestic Reliability Criteria

All of the measures described above can be developed without any change to B.C. Hydro's existing criteria for reliability. These criteria were described in detail in the filed testimony of the Applicants. The energy reliability criterion is based on the expected amount of unserved energy demand.

> "The energy reliability criterion used in planning the development of the B.C. Hydro system requires that the expected amount of unserved energy demand in any given year be less that 0.8% of total annual demand. For longer term studies, this assessment of system unserved energy takes into account the full range of demand outcomes, stream flow conditions and availability of energy from existing and planned facilities, including demand management programs. The energy reliability criteria (sic) applied in short term operational planning, where stream flow and weather uncertainty represent a more significant variable than demand outcome, the ability of the system to serve the probable demands for the full range of weather and stream flow outcomes, without deficits, is also tested."
>
> (Exhibit 2, Tab 2, p. 8 of 11)

The peak reliability criterion is based on the capacity reserve margin necessary to achieve a probability target for failure to satisfy peak demand.

> "... peak reliability criterion requires that B.C. Hydro have available sufficient capacity reserves such that the expectation of having insufficient capacity available to meet the forecast daily peak demand be one day in ten years or less. ... B.C. Hydro typically requires a capacity reserve of about 12% of installed capacity to satisfy its criteria (sic). Of this 12%, 400 MW is supplied by the reserve sharing provisions of the coordination agreement with TransAlta."
>
> (Exhibit 2, Tab 2, p. 9 of 11)

While some intervenors pressed B.C. Hydro on this issue, the Commission was satisfied that granting of this ERC should have no effect on B.C. Hydro's maintenance of its capacity and energy reliability criteria. These criteria are consistent with the standard practices in the electric utility industry, corrected for system differences.

3.4 Recommended Time-Frames Within the ERC

3.4.1 The Term and Magnitude of the ERC

The Commission accepts the Applicants' argument that the ERC should be interpreted as setting upper energy and capacity limits for exports. However, the Commission believes that this argument is especially valid if an important distinction is made between firm energy and capacity exports and the various other arrangements leading to trans-border electricity movement. These include system coordination, equichange, storage exchange, emergency exchanges, treaty commitments, border accommodations and interruptible exports. While the Applicants argued that all of the above are inextricably linked, along with firm exports, as the *gains from electricity trade*, the Commission believes that firm exports should be evaluated separately in terms of their net benefits. The reason is that it is possible to conceive of situations in which firm electricity exports have negative returns, while the other types of arrangements and exchanges may indeed be highly beneficial.[16]

Thus, the Commission recognizes that various types of non-firm exports and exchange arrangements should be allowed under the ERC, and in special circumstances the cumulative effect of these may come close to the upper limits applied for in the ERC (i.e. the trans-border transmission capability). For example, there could be a coincidence of (1) equichange return to the U.S., (2) a large sale of Alberta-generated electricity to the U.S., and (3) dramatically different water conditions in the U.S. and Canada leading to unprecedented opportunities for interruptible electricity exports. None of these conditions should have an impact on domestic reliability or security of supply, even though they may involve sizeable energy flows at the limits of the ERC Application.

The Commission recommends that an ERC period of six years (5 years remaining) is a reasonable time-frame for the review of policy with respect to those electricity exchanges that do not require additional investment and that have no potential effect on reliability and security of supply.

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16 For example, B.C. Hydro could conceivably maintain highly beneficial electricity interchanges (exchanges, coordination, shared emergency backup, etc.) while committing to an unprofitable electricity export contract for various reasons, such as (1) the contract eventually required unanticipated additional supply investments, or (2) the contract failed to fully account for all environmental costs. Thus, to the extent that the gains from export and the gains from other interchanges are independent, they should be assessed individually. Of course, instances can arise in which the two activities are interdependent. For example, an export contract could justify an increase in intertie capacity, allowing additional interchange benefits. However, in these cases any assessment of one activity (e.g. exports) should simply include all additional incremental benefits (e.g. enhanced interchange).

However, the Commission is of the opinion that components within the ERC will require different time-frames. In Section 3.3.1 above, the Commission recommended that firm contracts in excess of three years be defined as long-term, and not permitted under this ERC. In the following two sections, additional time-dependent requirements are recommended.

3.4.2 Firm Contracts of Less Than One Year

The hydraulic nature of the B.C. Hydro system, and its substantial water storage capability, supports the argument that situations may arise in which firm electricity exports of less than one year are justifiable because of water conditions.

The Commission recommends that the Applicants be allowed the flexibility to make firm energy and capacity commitments of one year or less without the need for Ministry approval. Such contracts could be regulated under the proposed PEO (see Chapter 4.0).

3.4.3 Firm Contracts of One to Three Years

To ensure that domestic reliability and security of supply are not jeopardized by individual short-term *firm* export commitments, the Commission recommends that all firm electricity contracts from one to three years in length be approved by the Minister of Energy.[17] To assist with the evaluation of the contracts, the Applicants should be required to provide the Minister with information that includes a detailed demonstration, like that of Table 3.2, that the domestic energy and capacity surplus available for firm export is indeed short-term firm surplus. The full list of required information is set out in Section 4.3.4.

The Commission also recommends that if firm energy and/or capacity from non-B.C. Hydro sources is included in the calculation of surplus exportable short-term surplus (i.e., Alberta, ALCAN and other IPPs), then the magnitude of each of these sources should be explicitly identified and each source should be evaluated for its impact on B.C. Hydro's criteria of reliability and security of supply. For identified sources the Applicants

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17 The Commission recommends in Section 5.5 that consideration be given to approval of electricity export contracts by the Minister of Energy *in consultation with* the Minister of Environment.

should be required to provide firm evidence of the incremental effect on B.C. Hydro's reliability and security of supply of each of the non-B.C. Hydro sources. This and other requirements are consolidated in Section 4.3.4.

3.4.4 Interruptible Contracts

These contracts are not deemed by the Commission to represent risks to the reliability and security of supply to B.C. customers. As will be discussed in Chapter 4.0, contracts of up to one year could be managed through the PEO, while longer contracts should be approved by the Minister of Energy.

3.5 The Free Trade Agreement

The Commission heard intervenor concerns that an increase or continuation in electricity exports to the U.S. as a result of this ERC may commit British Columbia to maintain minimum levels of exports under the FTA and pose a threat to domestic security of supply. This concern was based on the provision in Article 904(a) of the FTA that prohibits restrictions on exports that reduce availability of the energy other than in the proportions that prevailed in the preceding 36-month period.

Additional concern was raised about Article 904(b) which requires that no higher price be imposed on export sales, by way of licence, fee, tax, or other charge, than on domestic supply. The concern was that export customers could invoke this provision to require that any incentive price available to a domestic customer also be made available in the export market.

While it is clear that the FTA applies to regulatory actions that affect exports,[18] consideration of the FTA was not explicitly part of the Terms of Reference; nor reasonably implied within the scope of those Terms, given the complexity of the relevant FTA provisions. As a result, the Commission is not in the best position to advise the Minister of Energy or the Lieutenant Governor in Council as to the applicability or interpretation of the FTA in the context of this Application. Instead, the Commission has identified, especially in Chapter 4.0, issues that have potential FTA implications so that they may be taken into account in making a decision on this ERC Application.

> **The Commission therefore recommends that the Lieutenant Governor in Council seek advice on the application of the FTA to this ERC Application.**

18 Chapter 9 of the FTA specifically deals with the export of Energy Goods. Articles 103 and 905 indicate that provincial regulatory actions are to observe the provisions of the FTA.

4.0 MARKETING SURPLUS ELECTRICITY

The Commission's consideration of electricity marketing issues flows directly from Term of Reference 5 which states:

> " The Commission shall review the present offer mechanism, whereby electricity proposed for short-term removal by the Applicants is first offered to domestic interconnected utilities on terms and conditions no less favourable than the proposed removals, and determine whether this mechanism is the best method available for the purposes of demonstrating a removable energy surplus and providing evidence of a fair market price."

Prior to making the current Application for a new ERC, B.C. Hydro/POWEREX filed with the Ministry of Energy an application for approval of a short-term electricity marketing vehicle to be called the PEO. The PEO application was not filed at the ERC hearing; however, the ERC Application made it clear that the PEO was the Applicants' preference for engaging in trade of less than one year's term, and considerable evidence was presented at the ERC hearing on the operation of the proposed PEO. The Commission has therefore had to consider the proposed PEO as an integral part of the ERC Application for export and marketing of electricity.

4.1 Existing Energy Removal Certificate and Licences

Power and energy are currently being exported from British Columbia under Provincial Energy Removal Certificate 80 (8403) and under National Energy Board ("NEB") Licences EL-162 (firm) and EL-163 (interruptible).

The original Certificate and Licences were issued in 1984 and were due to expire on September 30, 1990. Subsequent extensions were granted to all export instruments to extend their validity to September 30, 1992. The original Certificate and Licences had limitations on the use of Burrard for export. This limitation was removed by amending Orders issued in 1987, after the station received its air emissions permit from the GVRD.

Both the above-described Provincial and Federal licences limit the electrical capacity which may be committed for export and the annual amount of energy of each class which may be removed from British Columbia. The Licences are currently held in the joint names of B.C. Hydro and POWEREX.

4.1.1 Price Tests

Both the above-described export permits apply price tests which are designed to ensure a positive net financial return to the exporter. Provincial ERC 80 (8403) requires that the price charged for firm or interruptible energy shall be:

(a) greater than the Applicant's incremental operating cost of supplying the particular class of energy. For the purpose of calculating the incremental operating cost, such costs shall reflect the weighted average price of hydraulic and thermal sources of electricity. The price to be charged to the purchaser by the Applicant for thermal electricity shall not be less than 100 percent of the incremental fuel cost of operating Burrard, calculated for natural gas valued at the greater of:

  (i) the Applicant's plant gate cost of natural gas, or

  (ii) if firm natural gas is used for generation of electricity for removal, the annual volume weighted average firm export price of natural gas removed from the Province, and

  (iii) if interruptible natural gas is used for generation of electricity for removal, the monthly volume weighted average export price of interruptible natural gas removed from the Province,

  plus 0.2 mills/kW.h for incremental non-fuel operating costs, plus any incremental capital costs that may be incurred as a result of the removal.

(b) not less than the Applicant's price for service to a purchaser of electricity within the Province capable of acquiring that quantity of electricity on similar terms and using that electricity in the Province.

(c) not materially less than the costs of alternative electricity available to the purchaser.

It should be noted that this last price test may be contrary to the intent of the FTA. A similar clause previously used by the NEB was eliminated by that agency in accordance with the requirement of paragraph 1 of Annex 905.2 of the FTA.

NEB Licences EL-162 and EL-163 (for firm and interruptible energy, respectively) apply a different minimum export price test. These Licences state:

" The price to be charged by the Licensee at the international border for hydroelectric energy, thermally-generated energy and any portion of the energy that would be replaced by thermally-generated energy shall not be less than the greater of:

(a) 105 percent of the incremental cost of production, purchase or replacement plus 3.0 mills per kW.h, or

(b) 11 mills per kW.h (Canadian funds).

For the purpose of calculating the incremental cost of production of operating the Burrard plant, the fuel component of this cost shall be calculated for natural gas valued at the greater of:

(i) the volume weighted average export price of natural gas from the Province during the time the export is made, or

(ii) the Licensee's plant gate cost of natural gas during the time the export is made."

4.1.2 Export Contract Approvals and Reporting

The Provincial Certificate ERC 80 (8403) requires no specific approval of interruptible energy contracts by the Minister of Energy. However, it does require specific Ministerial approval for ***all*** contracts for the export of firm power or energy.

Unlike ERC 80 (8403), NEB Licence EL-163 requires the approval of the Board for any sales contract for interruptible energy with a term greater than one month. For firm power or energy sales NEB Licence EL-162 requires Board approval of all export contracts. Both jurisdictions require regular reporting of all sales as to classification, price and quantity.

4.1.3 Offer Mechanism and Fair Market Access

Clauses in the Provincial ERC 80 (8403), designed to protect the interests of domestic consumers, require B.C. Hydro/POWEREX to first make available to all economically accessible interconnected B.C. utilities, the same quantity of electricity as that proposed for export to a purchaser in the U.S., on terms no less favourable than those offered to the U.S. purchaser. Effectively this requires B.C. Hydro/POWEREX to make a written offer to WKP, on each occasion, before concluding an export contract with a U.S. customer. There was evidence at the hearing that this "right of interception" has never been exercised during the eight years since the ERC was issued (T.Vol. 9, p. 1214). B.C. Hydro claimed, however, that the right of interception inhibited their contract negotiations (T.Vol. 9, pp. 1214, 1215). In contrast to the Provincial ERC, the NEB seeks to achieve protection of the domestic consumer by requiring exporters to provide "fair market access". Fair market access is described in considerable detail in Annex 2 to the Board's 1988 Statement of Canadian Electricity Policy (Exhibit 64). This annex outlines the Board's interpretation of fair market access, in part, as follows:

> "Exporters must ensure that potential Canadian buyers are kept informed about the electricity available for sale to external markets. Canadian buyers should be advised of the classes of service available, the quantities available, and the period for which the quantities are available; however, while negotiations with export customers are underway, price information may remain privileged.
>
> The Canadian buyer must then demonstrate a serious intent to purchase by, for example, telling the exporter the class of service it is interested in buying, the quantities it is interested in buying, and the period of the proposed purchase.
>
> When a Canadian purchaser (i) is interested in buying electricity to satisfy the requirements of its own domestic service area, and (ii) has demonstrated a willingness to negotiate the purchase of a class of service that is similar to that being considered by an exporter for sale to an export customer, then the exporter should ensure that the Canadian has an opportunity to negotiate terms and conditions (including price) no less favourable than those being offered to export customers."

This policy places an onus on the exporter to apprise domestic utilities of purchase opportunities, in a general way. It is clear that it also places an onus on a potential domestic utility purchaser to demonstrate an active interest in buying before serious consideration need be given to its requirements.

> **The Commission believes that, at least for the many transactions of short-term electricity trade of less than one year duration, adoption of a fair market access policy is preferable to the offer mechanism of the current ERC.[1] It appears that, with suitable operating procedures, the proposed PEO format could be made to provide the conditions necessary to assure fair market access.**

4.2 Trade of Less Than One Year

As outlined in Chapter 3.0, the Commission has few concerns related to security of domestic electricity supply as it relates to trade of less than one year's duration. Energy surpluses can be

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[1] It is possible that the current ERC offer mechanism could be interpreted as inadmissible under the Free Trade Agreement. In any event, its replacement with a fair market access policy on trade of less than one year's duration would eliminate that risk.

reliably determined, with low risk, during this short time-horizon, even in a period of narrowing demand/supply balances.

> **The Commission therefore recommends that Ministerial approval of export contracts of less than one year's duration should not be required. However, the ERC should prohibit the signing, in any year, of sequential export contracts of one year's term, with the same customer, for the same class of energy.**

4.2.1 Offer Pricing

The existing ERC and the existing NEB Licences take pains to ensure that British Columbia energy is not sold to any purchaser at a loss. The Commission believes it is important that this restriction be continued and, in fact, enhanced to ensure that an appropriate allowance is incorporated for environmental impacts related to the export sale. Without such restraints electricity exporters leave themselves open to charges of "dumping" under various trade agreements. Furthermore, it is likely that in future, some U.S. utilities (particularly those in Southern California) may attempt to require that environmental externality costs, relevant to impacts *at the point of production*, be incorporated into the selling price of energy transmitted into their jurisdiction. Such an attempt may be contrary to the GATT or other trade agreements, although relevant clauses are under review.

> **In order to ensure that export electricity is not sold at a loss, the Commission recommends that, for electricity trade of less than one year, the ERC incorporates conditions similar to clauses (a)(i) and (b) of Section 4.1.1 above, taken from the existing ERC (as amended).**

It is suggested that condition a(ii) of the existing ERC be dropped in the case of electricity trade of less than one year's duration. There was evidence that, even under the present ERC, information on border natural gas prices lagged so far behind electric energy spot sales contract negotiations that it was impossible to make this price test (T.Vol. 10, pp. 1339 and 1342). Doubts were also expressed about the validity of the assumption, in the current state of gas availability, that operation of Burrard on natural gas would, in reality, displace a gas sale from the Province (T.Vol. 10, pp. 1339-1341). Certainly, if the PEO is instituted, the rapid execution of many very short-term contracts will make the application of such a price test patently impracticable.

In addition, B.C. Hydro and any other British Columbian agency selling short-term energy (less than one year) for export should be required to move towards incorporation of an appropriate allowance, in its selling price, for social/environmental costs associated with the generating source. In practical terms, this may need to be done in conjunction with interconnected utilities. A condition of the ERC should require B.C. Hydro/POWEREX to annually report progress toward this goal in the POWEREX year-end operational review.

B.C. Hydro stated on numerous occasions that it normally sought a 0.5 cents/kW.h margin over cost in pricing its energy exports. The Commission accepts this as a conservative allowance to ensure that, until such time as the social and environmental costs of export generation are incorporated into the selling utilities' price, all such undetermined costs and risks will be covered. Logically, this margin should be on a sliding scale related to the generating source: highest for coal-fired generation (eg. from Alberta) and lowest for hydraulic generation.

Until such time as consistent environmental externality valuations are incorporated into the pricing structures of utilities selling export energy in the one year term, the Commission recommends that a minimum margin of 0.3 cents/kW.h over weighted average incremental cost be required on all energy exports.

It should be noted that there is a minimum margin requirement of 0.3 cents/kW.h in the current NEB export licences issued to B.C. Hydro/POWEREX.

The incorporation of environmental externality costs in energy sales does not address the issue of the ultimate recipient of the environmental cost increment. So long as B.C. Hydro is the sole supplier to POWEREX and so long as POWEREX is a wholly-owned subsidiary of B.C. Hydro, all net revenue, including the environmental increment, when incorporated, will ultimately flow into the hands of the British Columbia public, either as rate-maintenance assistance or, via dividend, to the Provincial treasury. When B.C.-based IPPs eventually participate in export trade other methods will have to be considered to ensure public recapture of the environmental increment eventually required to be incorporated in the IPP's selling price.

4.3 The Proposed Power Exchange Operation

B.C. Hydro/POWEREX, in their Application, proposed the establishment of a PEO for short-term trade of less than one year in power, firm and interruptible energy and other services. The introduction of such a system is compatible with the Commission's view that short-term trade should be freed as much as possible from unnecessary procedural constraints so as to maximize the resulting benefits to the Applicants and the Province.

> **Based on its preliminary review during the hearing, the Commission finds that the concept of the PEO has merit. The Commission therefore recommends, subject to specific constraints outlined below, that the Minister consider the use of the proposed PEO as the vehicle to conduct export trade of less than one year's duration.**

It should be remembered that, in making this recommendation, the Commission has been able to consider only the evidence presented at its hearing. The ERC Applicants did not provide a copy of the full application for PEO approval made to the Ministry of Energy.

Information on the proposed PEO operation was provided in Exhibit 1, Appendix 8, and the B.C. Hydro policy panel gave extensive evidence as to how they proposed to operate the system, if approved. From the ERC Application it appears that B.C. Hydro will retain responsibility for border accommodation transfers, Canadian Treaty obligations, coordination, and other support transactions. All other electricity trade will be in the hands of POWEREX which is proposed as the operator of the PEO for marketing electricity and related services under contracts of less than one year's duration.

It appears that POWEREX proposes to market short-term (less than one year) energy, through the PEO, in the manner in which it has historically marketed B.C. Hydro's surplus electricity. That is, it proposes to continue to purchase surplus short-term energy at the utility's incremental cost and sell it (after shaping, if necessary) at market prices. The cost differential accrues to POWEREX and, after the payment of administration and other POWEREX costs, is recorded on the books of POWEREX as a profit from electricity export trade.

Presumably, in the case of Alberta surpluses currently marketed by POWEREX, the Alberta utility sells to POWEREX at a price which covers its incremental cost plus whatever margin it is prepared to accept. After purchase and resale, POWEREX's costs in this transaction include administration and external costs as well as domestic costs for wheeling and shaping services paid to B.C. Hydro and the difference is recorded by POWEREX as a profit.

Since POWEREX is a wholly-owned subsidiary of B.C. Hydro its profits eventually flow back to the latter corporation whose consumers have paid for the storage and transmission facilities which make these transactions possible. So long as the POWEREX /B.C. Hydro relationship is maintained, and B.C. Hydro is the sole domestic supplier to POWEREX, the Commission has no conceptual difficulty with POWEREX'S operation of the PEO for short-term electricity trade of less than one year.

The Commission's concerns relate firstly to the growing conflict of interest which will develop when IPPs join the system in competition with B.C. Hydro and, secondly, to the importance of maintaining fair market access for energy purchases by domestic utilities. These concerns are discussed below.

4.3.1 PEO Conflict of Interest Potential

Initially the B.C. Hydro system will be the only contract system in the PEO. However, it is a stated objective of POWEREX to eventually encourage as many IPPs as can qualify to participate in the exchange through membership, through the sale of surplus energy and through energy purchases. Because of its ownership by B.C. Hydro, the dominant exchange player, POWEREX is likely to find itself in a growing conflict of interest position as IPPs join the exchange. Conflicts of interest could result from early market intelligence flowing between POWEREX and B.C. Hydro despite the best attempts to maintain an arms-length relationship between the two related parties. For example, an IPP might commit all its resources to an export contract only to learn, too late, of a more attractive offer being discussed between POWEREX and a U.S. utility from which B.C. Hydro might subsequently profit. Admittedly, if and when IPPs join the PEO, they will be aware of this potential conflict and may well accept it, in return for the opportunity to participate in a lively short-term export trade. POWEREX itself, is clearly concerned about the potential conflict of interest and proposes steps to minimize this risk (Exhibit 1, Appendix 8, p. 3).

> "B.C. Hydro is a regular PEO member for all buy and sell transactions. Initially, it will be the dominant player in sell transactions to the PEO. Rather than transacting at the posted prices, B.C. Hydro nominates fixed monthly buy and sell prices to the PEO. B.C. Hydro is always last in the transaction order in order to avoid any conflict of interest–whether real or perceived–as a result of its being the PEO contract system. Further, B.C. Hydro wants to allow the short term market to develop and all players to have the opportunity to participate in the PEO."

It is the Commission's view that this potential conflict of interest situation may be acceptable so long as B.C. Hydro is the dominant participant, and the risk may be acceptable to ensure the successful launch of an electricity exchange, with the benefits this will bring to short-term electricity trade.

> **However, the Commission believes that the PEO should eventually move towards operation by an independent entity on a "fee for service" basis.**

Independent operation would require every participant, including B.C. Hydro, to separately determine the all-inclusive price at which it was prepared to sell its own block of short-term (less than one year) electricity, to determine the price at which it was prepared to purchase electricity through the exchange, for its own account, and to post offers accordingly. The exchange would merely provide a brokering service.

4.3.2 Priorities and the Position of Domestic Purchasers

The primary means for creating an active short-term market for electricity with the proposed PEO will be by the posting of buy and sell prices on an electronic bulletin board. The PEO proposes to post buy and sell prices and quantities[2] of energy and capacity available for hourly, daily and monthly transaction. In addition, the PEO will provide unbundled and bundled services to its members at prescribed prices (Exhibit 1, Appendix 8, p. 2). Posted prices will be made available to all interested parties by subscription to the Dow Jones Telerate publication (Exhibit 63) and by fax or telephone from 8:00 a.m. to 4:00 p.m. on working days.

Nominations received in response to these postings are accumulated until 11:00 a.m. on the day preceding the start of requested delivery. Nominations are then scheduled for the next day's delivery. As soon as the next day's schedules have been established at 11:00 a.m., the prices of subsequent transactions are subject to change depending on market response (T.Vol. 22, p. 1208).

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2 There was conflicting evidence on this point. Exhibit 1, Appendix 8, p. 5, paragraph 3.3, line 2 and Exhibit 63 clearly indicate the posting of quantities. Mr. Epp's evidence (T.Vol. 9, p. 1201, lines 10-16) implies quantities may not be posted but he does not explicitly say so.

POWEREX proposes to priorize delivery transactions, from nominations received before the cut-off time, according to the greatest net financial benefit to the PEO, not necessarily according to the highest price offered (Epp, T.Vol 9, p. 1220).[3] In addition POWEREX indicated it would consider off-exchange short-term transactions (less than one year) in rare cases, where a transaction because of its special nature would require a lot of non-standard transaction clauses (T.Vol. 9, p. 1205).

WKP, through counsel Mr. R.H. Hobbs, posed a number of questions related to how a variety of hypothetical competing nominations would be dealt with. POWEREX'S responses made it clear that, while the criterion of greatest net benefit to the PEO was proposed to govern in all cases, a set of complex procedural rules would be required to eliminate confusion among participants in the actual bidding process. Such rules will be published and available to all members (T.Vol. 9, p. 1221).

WKP also explored the right of interception by domestic utilities and was told that no such mechanism was proposed. Instead, WKP was told by Mr. Epp, for POWEREX, that all participants and potential participants would be given fair market access through an equal flow of timely information on the availability of electric energy for sale or purchase. POWEREX pointed out that domestic participants have innate cost advantages over U.S. participants because of lower transmission line losses and freedom from concern that transactions will be blocked by restrictions on transmission interties.

In closing argument WKP made the point that if sales are scheduled on the basis of the greatest revenue to the PEO, as proposed by the Applicant, rather than the basis of highest unit price, this would be tantamount to giving priority to U.S. purchasers because U.S. customers will typically purchase in larger volumes than domestic customers (T.Vol. 22, p. 3605).

With respect to the above issues, the Commission believes that the principle of maximizing financial returns to the PEO in scheduling transactions (subject to the constraints of environmental costs discussed in Section 4.2.3) is consistent with the objective of maximizing the return to B.C. utilities and IPPs from the sale of surplus electricity. At the same time, in the absence of a right of interception, the Commission is cognizant of the need to provide domestic consumers a fair

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3 There was conflicting evidence on this point also. Mr. Dunlop, counsel for B.C. Hydro/POWEREX, in Argument, stated that all purchase offers which met the posted price would be treated equally and pro-rated if necessary (T.Vol. 23, p. 3808).

opportunity to participate in energy purchases without being disadvantaged vis a vis large scale U.S. purchasers.

The Commission therefore recommends that approval of exports through the PEO be conditional on incorporation of the following constraint in the PEO's Operation Rules:

Where timely offers are received by the PEO from both Canadian and U.S. purchasers for purchase of electricity of the same class, either interruptible or firm, for delivery commencing on the same day, and the Canadian purchaser has offered a unit price the same as or greater than the U.S. purchaser, the domestic nomination shall be scheduled first, even if the export purchase offer by virtue of volume might have yielded a higher net benefit to the PEO. Nothing in this rule is intended to prevent the scheduling of an export order to the extent possible after the domestic order has been scheduled.

4.3.3 Reporting PEO Transactions

If, under the PEO, the right of domestic utilities to intercept export sales is eliminated, then the PEO must be at pains to ensure fair market access for all participants, including domestic utilities, so that the latter will not be disadvantaged. The foundation of a fair market access policy is grounded in up-to-date knowledge of market activities. In an era of electronic posting of buy/sell prices the flow of related market information must be equally efficient to ensure fair and knowledgeable access to the market by all participants.

The Applicant expresses the view (T.Vol. 1, pp. 144 and 145) that electronic posting of buy/sell quantities, classes of service and forecast prices from one day to six months forward, when taken together with availability of the B.C. Hydro Electricity Plan, will provide fair market access. The latter document is updated annually; it discusses demand on the B.C. Hydro system, supply side options, short and long-term strategies. Supply side options include limited information on IPPs some of whom will probably eventually participate in the PEO. In addition, the Applicant proposes to provide an annual operations report (T.Vol. 1, p. 145). Presumably this will be similar in content to the currently issued POWEREX Annual Operational Review (Exhibit 78) but will deal exclusively with trade of less than one years duration. Exhibit 78 provides an excellent retrospective review but would be of little value to the day-to-day decision-making of a short-term electricity trader.

> **It is the Commission's recommendation that, in addition to the daily posting of quantities and buy/sell prices, consideration should be given to requiring publication of a daily trading summary of all short-term (less than one year) trades to be made available electronically to all PEO participants.**

This trading summary could be part of the Dow Telerate publication or could be faxed directly to participants the day following scheduling of any consummated transaction. The trading summary should contain information on the nature of the electric commodity bought or sold; the sales volume; the transaction price; the name of the buyer; the date of first delivery and the term of the contract; whether the transaction was made on or off the PEO.

This information is considered essential for two reasons. First, to allow market participants, including potential domestic buyers, to track volume and pricing trends to ensure better-informed participation in exchange activities. Second, because of PEO policy to accept those offers showing the greatest net financial benefit to the exchange, it will be important that participants who may have bid, either at, above or below the posted price, be able to clearly see why their offer may have been pre-empted. It will be important not only that operating rules are clearly promulgated but that all participants will at all times, have public assurance that those rules have been respected.

It is not suggested that these daily trading reports be required to be filed with the Ministry of Energy. It is believed the latter will be better served by an annual Operations Review Summary which it recommends be made a condition of the ERC. It will be important, however, to require that copies of daily trading summaries be filed with the Oversight Committee or whatever public agency is assigned oversight of the PEO.

4.3.4 The B.C. Hydro/POWEREX Relationship and Governance of the PEO

(a) B.C. Hydro and POWEREX

POWEREX is a wholly-owned subsidiary of B.C. Hydro. Pending the development of major private generation sources to supply the long-term export trade, which was its original mandate, POWEREX appears to have been given the task of coordinating the export of B.C. Hydro's short-term surplus energy, as defined by B.C. Hydro (i.e. energy surplus to B.C. Hydro's immediate needs and generated using facilities already built to meet B.C. Hydro's domestic market).

In fact, since its formation this interim role has dominated its activities. In addition, it has facilitated and marketed the export sale of surplus energy generated by private utilities in the Province of Alberta. Operation of the proposed PEO would be a new, but related role for POWEREX, moving the corporation still further from its original objective. Nevertheless, the Commission believes there is logic to the proposal that the PEO be initiated and operated by POWEREX.

Over the past four years POWEREX has built up a team of personnel skilled in the negotiation of short-term firm and interruptible contracts and in the sale of related services. They are obviously well known to prospective purchasers and knowledgeable of the resources available within the B.C. Hydro system. So long as B.C. Hydro is the sole, or at least the dominant player, in electricity exports, POWEREX's status as a wholly-owned subsidiary of B.C. Hydro is not inappropriate. It is clear from the supply/demand forecasts for the term of this Application that B.C. Hydro's facilities are likely to provide the greater part of British Columbia-generated surplus electricity under all except critical water conditions. The role of POWEREX in the PEO will almost certainly have to be reviewed in future after long-term electricity export policies have been determined by the B.C. Energy Council or if there is increased short-term activity by IPPs in the export market.

(b) Governance of the PEO

The Applicants propose the creation of an Oversight Committee to oversee the conduct of the PEO. Limited information on the proposed Oversight Committee was provided to the Commission hearing (T.Vol 10, p. 1330). It was suggested that the Oversight Committee's duties would include review of the PEO's Operation Rules; review of complaints from participating members or from POWEREX; resolution of complaints; suspension of members for cause; receipt of member and public feedback concerning operation of the exchange.

The make-up of the Committee is not defined. It would appear logical that it include representatives of the POWEREX Board of Directors, who have ultimate responsibility for the operations of the Corporation and representatives of the exchange membership (participants). It is proposed that the Committee report directly to the Minister (T.Vol. 10, p. 1330, line 14) and it is specifically proposed that the Minister be advised of the exchange's Operation Rules and be kept advised of any material changes made to them (T.Vol. 10, p. 13312, line 8).

The Commission believes that an Oversight Committee has practical value for the exchange's members, but that it should not be considered a substitute for public scrutiny and regulation. In effect, whatever its specific legal status, the PEO, if it functions as envisaged, will by function be a public utility operating in part within the Province of B.C. As such, the Commission believes that if the PEO is approved, its regulation should be placed in the hands of the Commission.

4.4 Short-Term Trade Over One Year Duration

4.4.1 Firm Exports

Contracts of greater than one year's duration are proposed by the Applicant to be conducted outside the PEO. These contracts will be sought out by, and executed by POWEREX based on direct negotiation with purchasers.

For reasons set out in Chapter 3.0, the Commission recommends that export contracts for firm energy of duration longer than three years be defined as long-term and should not be permitted under this ERC.

The Applicants made it clear (Exhibit 2, Tab 1, p. 9) that the main thrust of export marketing would be the sale of surplus under firm sales agreements. The attraction of such sales is the better profit margin achieved. The evidence of the past five years (Exhibit 5, BCUC Information Request 1.3) discloses firm sales margins in the order of 1.5 to 2.5 cents/kW.h compared with margins in the order of 0.5 to 1.5 cents/kW.h for spot and interruptible contract sales.

The emphasis on firm sales in the one to three year time-horizon, while understandable in the context of maximizing POWEREX revenue, will require greater caution than ever in view of B.C. Hydro's shrinking supply/demand ratio, discussed in Chapter 3.0. This is particularly true as firm surplus becomes increasingly dependent on purchased power from IPPs and Alberta sources. The possibility of having to cover firm commitments with unexpected purchases could expose the electric consumer to financial risk.

4.4.2 Interruptible Exports

Although longer-term sales of interruptible energy have been rare in the past, it is conceivable that future market conditions could create a situation where lucrative sale contracts for interruptible energy might be possible over a succession of years. Since these transactions could be curtailed should adverse circumstances develop, they pose little threat to the Province's domestic supply.

In the interests of maximum flexibility, the Commission recommends that interruptible contracts of any term up to five years be permitted, subject to satisfactory margins, and the protection of the interests of domestic utilities by the provision of fair market access.

However, because of the unusual nature of such long interruptible contracts the Commission recommends (Section 4.4.4) that all interruptible contracts over one year in length, up to a maximum of five years, be required to be submitted to the Ministry for scrutiny, and that the most probable sources of supply be identified by the exporter.

4.4.3 Offer Pricing and Domestic Priorities

(a) Price Tests

The pricing of export energy, either firm or interruptible, longer than the one year contract term should, in the view of the Commission, continue to be subject to minimum price tests compatible with the FTA.

The Commission recommends that the minimum price tests set out in paragraphs (a) and (b) of Section 4.1.1 above (taken from the existing ERC) should continue to be a requirement of electricity trade over one year but that this test should be supplemented by a 0.3 cents/kW.h additional margin requirement.

The reference to the weighted average export price of natural gas removed from the Province is appropriate in this case in view of the fact that longer-term electricity sales are the subject of specific contract documentation which may take several months to develop. Thus natural gas export price information, normally received by B.C. Hydro/POWEREX some months in arrears (T.Vol. 10, p. 1342) can be taken into account in contract negotiations.

B.C. Hydro gave evidence at the hearing that exports were generally made only when revenues exceeded system marginal cost by about 0.5 cents/kW.h (T.Vol. 22, p. 3579). However, in one particular case (Exhibit 60) the margin dropped to 0.3 cents, the floor margin specified in NEB Licences. There was evidence that this target 0.5 cent margin over system incremental costs was a catch-all to cover unidentified costs, including an allowance for undetermined social and environmental impacts.

The Commission believes that, for future export contracts in excess of one year term, B.C. Hydro/POWEREX and B.C.-based IPPs should eventually be required to incorporated appropriate environmental *adders* to the cost of each source of export generation. However, the Commission recognizes that this cannot be done in isolation from other members of the Western Systems Power Pool ("WSPP"). For reasons given in Section 4.2.1, as an interim measure, the Commission believes it appropriate that POWEREX be required to maintain a minimum 0.3 cents/kW.h margin (already required by the NEB licences) over system incremental cost to allow for unidentified social/environmental impacts of generation until such time as they are specifically incorporated into the domestic supplier's price.

The comments of Section 4.2.1 concerning the probable future requirement of California buyers that prices include an environmental allowance, and the risk of *dumping* charges if they are not incorporated, are as valid for longer-term contracts as they are for one year trade.

(b) Domestic Access to Contracts

It is presumed that negotiations for contracts of duration longer than one year, unlike those executed through the PEO, will be carried out under conditions of commercial confidentiality. It is, therefore,unlikely that all the conditions required by the NEB's "Fair Market Access" policy will exist for potential Canadian purchasers. Under these circumstances, the easiest and most direct way to ensure that a Canadian utility, interested in purchasing B.C. Hydro or IPP short-term surplus electricity for use in its own domestic service area, has access to that energy on terms no less favourable than those offered an export customer, is to continue restrictions in the ERC equivalent to existing clauses 8 and 12. Clause 8 states:

> "The Applicant shall not remove or agree to remove any quantity of firm power or firm energy from the Province without first making available that quantity of firm power or firm energy, on terms not less favourable than those negotiated with the purchaser in the USA, to all economically accessible interconnected electrical utilities within the Province capable of using within the Province that firm power and firm energy."

Clause 12 is similar but relates to interruptible energy.

If such *right of interception* were to be interpreted to be in violation of the FTA, then it is suggested that the Applicants be expressly required to institute a fair market access policy. This could possibly be done by providing monthly up-dated information to all potential domestic utility purchasers. Such notices would indicate the type, amount and duration of availability of all blocks of energy expected to become available for export in the one year and over time-frame. The onus would then be squarely on the potential Canadian utility purchaser to express a serious interest in any block available.

> **The Commission recommends that, for electricity trade of greater than one year's term, the Applicants be required to institute a fair market access policy by keeping domestic utilities advised on a regular monthly basis of surplus energy opportunities, as they arise.**
>
> **In the event of a formal Canadian purchase offer, the Applicants should be obliged to give priority to that offer so long as the unit price offered for energy or service was the same as, or greater than any competing export offer for the same block of energy or service, or any part thereof, without regard to the quantity of energy or service involved in the respective offers.**

4.4.4 Approvals and Reporting

(a) Approval by the Minister

The Commission recommends that the ERC require the approval of the Minister of Energy[4] for *all* electricity export contracts in excess of one year's duration.

Specifically, the application for approval should be required to provide the following information:

(i) In the case of firm energy sales, the expected sources of supply should be clearly identified and the Applicants should be able to clearly demonstrate that the sale will have no adverse effect on the security of domestic supply during the period of the proposed exports. This demonstration should be similar to that of Table 3.2 in the case of firm sales, to show that the surplus is indeed a *short-term* firm surplus.

(ii) The price to be obtained from any sale shall meet minimum price tests so as to demonstrate a positive margin over the utility's incremental cost of production, including an allowance for environmental and social costs related to the proposed sources of supply. Until the time when the latter allowance can be separately identified, it is recommended that such costs be deemed to be 0.3 cents per kW.h.

(iii) Interconnected domestic utilities shall be shown to have been given at least a fair market opportunity to acquire surplus energy on no less favourable unit-price terms than a foreign purchaser.

(iv) Assurance that there will be no change in the Applicants' reliability criteria.

(v) Assurance that there will be no adverse environmental effects which cannot be mitigated.

(vi) The Applicant shall demonstrate that the sale price is reasonably close to the avoided cost of the purchasing agency.

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4 The Commission recommends in Section 5.5 that consideration be given to approval of electricity export contracts by the Minister of Energy *in consultation with* the Minister of Environment.

During the ERC hearing the public availability of B.C. Hydro/POWEREX electricity export contracts became an issue. The Commission realizes that disclosure of detailed contract terms may be commercially sensitive.

However, it believes that contract summaries showing purchaser, class of sale, contract term and price should be required to be filed with the BCUC and available for public scrutiny. A filing time lag of 90 days may be appropriate in view of the likelihood that concurrent commercial negotiations for similar blocks of energy may be underway between B.C. Hydro/POWEREX and other purchasers.

(b) Required Reports

It is recommended that for export trading contracts of over one year's duration B.C. Hydro/POWEREX be required to report specified export-related trading information to the Minister of Energy at no greater than annual intervals.

It is suggested that reported information be required to include the following:

(i) The net amount of power and energy of each class exported from British Columbia to the U.S. during the preceding period.

(ii) The net amount of power and energy of each class imported into British Columbia from Alberta during the preceding period.

(iii) The sum of export contract commitments for firm power and energy still outstanding for delivery outside the Province during subsequent periods.

(iv) The weighted average price obtained for each class of export during the preceding period and the net revenue thereon.

(v) The net amount of energy supplied for export by IPPs located within the Province and the weighted average price of such purchases.

4.5 Domestic Residential/Commercial Customer Access to Interruptible Electricity

A number of hearing intervenors questioned why B.C. Hydro's domestic residential/commercial customers could not be offered surplus interruptible electrical energy, for space and water heating purposes, at the very low rates obtained by foreign purchasers of exportable surplus electricity. It was argued by the Applicants that:

(i) Purchasers of low-cost export energy receive wholesale bulk supplies, usually on an interruptible basis at high voltage. The cost of this energy could not be compared with the cost of interruptible retail electricity delivered at low voltage to residential customers.

(ii) If a residential customer were to be supplied with an interruptible product he/she would have to have an alternative energy source for use during curtailment.

(iii) Even with an alternative source, it was not practical to curtail domestic customers to meet a supply crisis, since a long notice period would be required.

The E-Plus program, designed for areas where gas was not available, was instituted by B.C. Hydro, several years ago, in an attempt to provide low cost surplus electricity for residential space and water heating. With tightening electricity supply, less assurance of available surplus and taking into account the practical difficulties related to interrupting a domestic customer, this program was capped in 1990, although existing E-Plus customers continue to be supplied.

One of B.C. Hydro's concerns was that the program sent the wrong conservation signals. A second concern was that, if customers were curtailed during a series of critical low water years, the curtailment would probably have to be for one or more years.

The Commission understands the practical problems outlined by B.C. Hydro. At the same time it is sympathetic to the logic of intervenors who wonder why domestic commercial/residential customers should not get first priority for surplus low-cost energy prior to its export, so long as they are prepared to accept the limitations of interruptible supply, or the equivalent thereof.

The Commission points out that low-cost interruptible electricity could be supplied to residential customers under a two-step tariff in which, when "interruption" would normally take place during low water conditions, a much higher rate would kick-in, reflecting the higher cost of B.C. Hydro's thermal generation or purchased energy. As with the E-Plus program, customers would be required to have alternative heat sources. If the tariff step were sufficiently large, the price change would send the appropriate pricing signal and would have an effect similar to interruption. However, in this case, customers could make the choice between paying the extremely high rate or utilizing their back-up heat source.

> **It is recommended that B.C. Hydro be instructed to examine the feasibility of implementing a two-step tariff, similar to that described above, to allow domestic commercial/residential customers access to part of B.C. Hydro's otherwise exportable surplus, as an alternative to exporting it. It is recommended that B.C. Hydro report its findings before December 31, 1992.**

5.0 ENVIRONMENTAL IMPACTS OF EXPORT GENERATION FROM HYDROELECTRIC FACILITIES AND FROM ALBERTA PURCHASES

The following section of the report responds to Clause 6 of the Terms of Reference:

> "The Commission shall review the Application to assess the environmental impacts from the proposed removals (of electrical energy) and whether the Applicants' operating practices are adequate to mitigate any unacceptable impacts ..."

Subsequent clauses go on to deal with specific issues surrounding the use of Burrard which is the subject of Chapter 6.0. This section discusses the environmental impacts of generation from sources other than Burrard, when used to support electricity exports.

5.1 The Applicants' Position on Environmental Impacts in General

The Applicants expressed three primary views on the environmental impacts of their export generation activities. These were:

(i) Export energy is surplus energy derived from operation of the entire B.C. Hydro system and it is difficult, if not impossible, to pinpoint a single source of generation. Even in the case of exports supported by Alberta purchases, the energy is often taken into the B.C. Hydro system and re-shaped for delivery in a different time-frame.

(ii) B.C. Hydro, at all times, operates its facilities in conformity with the various provincial licenses and certificates which govern them. This in itself implies that environmental impacts are deemed acceptable.

(iii) The cost of environmental impacts from different sources of generation have not yet been quantified. In common with other North American utilities, B.C. Hydro is moving towards better identification of these impacts and costing of them. In the meantime, the energy export price target is set sufficiently high that these costs are well-covered when export sales are made.

In addition to the above, the Applicants testified that in many cases, when B.C. Hydro is made aware of an environmental problem related to its operations, it takes voluntary action to help seek a solution by adjusting its operating procedures. Intervenors were less confident of these responses and were critical of B.C. Hydro's record on *collaborative* and *rapid* reaction.

With respect to item (ii) it should be noted that early water licences contained such broad constraints that they have little reference to day-to-day dispatch decisions. As a first step to more environmentally sensitive reservoir operation the Commission recommends that such licences be reviewed and updated.

5.2 Impacts of Generation from Hydraulic Resources

Intervenors at the hearing raised a number of concerns related to the environmental impact of B.C. Hydro's hydroelectric operations. It was sometimes difficult to relate these concerns to the incremental effect of export operations, as distinct from the utility's operation for domestic purposes which typically accounts for more than 90 percent of its activity. The Applicants themselves testified that incremental changes in system operation due to exports are overshadowed by the total system operation (T.Vol. 3, p. 349).

5.2.1 Reservoir Effects

The most significant environmental effects from reservoir operation were identified as fishery related. Recreation is also impacted by the effect of changing water levels which can leave boat landings and launching ramps stranded and which can reduce the aesthetic pleasure of reservoir shorelines. In cases where reservoirs are used for industrial transportation, rapidly changing levels can complicate operations. In the case of the Arrow Lakes reservoir, dust storms have been reported from an arid sandy drawdown zone.

Rapid drawdown in response to large energy export contracts was seen by intervenors as a specific export concern. In response, B.C. Hydro attempted to provide a measure of the magnitude of export effects on reservoirs by providing hypothetical examples for the Williston and Mica storages which demonstrated that even the largest export sale, if sourced *entirely* from one of these reservoirs would effect drawdown levels by a matter of inches, or fractions of an inch per day. Reservoir drawdown from Non-Treaty storage was identified by the Applicants as beneficial by virtue of its potential to be used for improved flood routing capability (T.Vol. 4, p. 523; Vol. 18, p. 2801).

5.2.2 River Fluctuations

Fluctuations of river levels downstream from reservoir storage results from the operation of hydroelectric turbines. Spill has similar effects although, for economic efficiency reasons, spill is minimized. In spite of the fact that regulated flows are likely to be much less variable than in an unregulated river system, the effects of short-term variations from turbine releases into relatively narrow channels with sensitive eco-systems can be important. The most serious effect of river level fluctuations is on the spawning and migration of anadromous fish species. These effects have been extensively documented for most B.C. Hydro projects through joint studies with Federal Fisheries (Exhibits 107A and 107B) and operating procedures continue to be adjusted in response to these studies. A number of other cases of joint studies with government agencies to investigate and respond to operating concerns were cited (T.Vol. 16, pp. 2239, 2243 et seq.).

Particular reference was made by the Trail Wildlife Association during the hearing, to the impact of river flow fluctuations on the upper Columbia River reach immediately north of the U.S. border. This is the last free-flowing stretch of the Columbia in Canada and an area of great recreational fishery potential. In addition, the same area offers riverside tourist recreation which can be adversely affected by rapid variations in river flows and water levels. B.C. Hydro was urged to consider these potential values in the operation of its Columbia River reservoirs.

5.2.3 Operating Practices Review

The Commission believes that operation of B.C. Hydro's reservoirs might benefit from closer scrutiny by government environmental agencies, in collaboration with the Utility.

> **The Commission recommends that, as a first step, water licences for major B.C. Hydro reservoirs be reviewed and updated by the Ministry of Environment.**

The Commission concludes that the environmental impacts from the operation of B.C. Hydro's hydroelectric resources for export is relatively small. In fact, in financial terms, they may approach zero when benefits and costs are equated. This is not to say that specific operations cannot be improved nor that attempts to quantify and minimize adverse impacts should not continue.

The Commission heard evidence that BPA is currently conducting a System Operation Review ("SOR") of its facilities on the lower Columbia River. Since Canada contributes some 25 percent of the water to the Columbia Basin it was surprising to learn that B.C. Hydro has no formal participation in this review. The purpose of the review is to construct improved hydro-regulation computer models which will permit better understanding of reservoir and river impacts on the environment by measuring and quantifying the incremental impact of dispatch decisions on a range of resources from fish and wildlife to recreation and tourism. The Commission concludes that similar modelling would be appropriate for B.C.'s major river basins.

The Commission recommends that the Applicants review the operating practices of their principal hydroelectric systems to ensure that dispatch decisions will minimize impacts and optimize benefits from system operation in support of exports. This should be done in a manner similar to their BPA counterparts in the Columbia River SOR. Progress towards this objective should be required to be reported annually.

5.3 Other Environmental Impacts of Export Generation

5.3.1 Alberta Generation

Alberta generation can provide the source for some of British Columbia's export trade. Alberta energy purchases by the Applicants are normally supplied from coal-fired resources. To the extent that this generation may be substituted for gas-fired thermal generation in the importing region there could be a net contribution of carbon dioxide, sulphur dioxide, and particulates to the North American environment.

In contrast, when water-based exports are occurring, there is an environmental benefit as such exports usually displace U.S. thermal generation.

5.3.2 Electromagnetic Effects from Transmission

Concerns expressed were of a generic nature. The difficulty in isolating the specific effects of export generation was again emphasized by the Applicants although it was conceded that EMF effects of exports would be most marked in the vicinity of the export interties near the borders of the Province. Even in these lines there will be energy exchanges and loop flows at times when there are no net removals taking place.

5.4 General Commission Recommendations

(i) In order to improve awareness among regulatory agencies of possible environmental impacts from potential major electricity contracts:

The Commission recommends that the Minister of Energy give consideration to approval of export contracts over one year's duration *in consultation with* the Minster of Environment.

If the latter recommendation is accepted it will be necessary to ensure that this additional approval does not create delays which could affect desirable export opportunities.

(ii) The ERC may entail the export to the U.S. of significant quantities of coal-generated electricity from Alberta.

The Commission recommends that the Applicants be directed to develop, together with other interconnected utilities, a mechanism for incorporating environmental externalities from different energy resources into the price of electricity and into dispatch decisions.

6.0 SPECIAL CIRCUMSTANCES RELATED TO THE USE OF THE BURRARD THERMAL GENERATING STATION

6.1 Introduction to Burrard

The Terms of Reference provide specific criteria for the Commission in regard to the environmental impacts of the proposed removals that involve the Burrard facility as follows:

> " The Commission shall review the Application to assess the environmental impacts from the proposed removals and whether the Applicants' operating practices are adequate to mitigate any unacceptable impacts and, in particular, the Commission shall:
>
> (a) conduct a review of the role of the Burrard Thermal Generation Station (Burrard) in serving the export market; and,
>
> (b) assess the impact on the Lower Mainland airshed, under various meteorological conditions, of the air emissions which can be directly attributable to increased generation from Burrard to serve the export market; and
>
> (c) consult with the Ministry of Environment, Lands and Parks and the Greater Vancouver Regional District to ensure that any studies/modelling which may be necessary for assessing the environmental impact of the operation of Burrard are adequate to reach reliable recommendations."

6.1.1 The Burrard Generating Station Facility

(a) The Plant

The Burrard generating station is located on the north shore of Burrard Inlet 16 km east of downtown Vancouver in the area of Ioco. It is located within the Municipality of Port Moody and within the GVRD.

Construction of the six-unit plant began in 1958, with the first unit brought into service in 1962 and the last in 1975, for an installed capacity of 912.5 MW (units 1-5, 150 MW each and unit 6, 162.5 MW) The plant is theoretically capable of producing 7994 GW.h of energy, however, for practical purposes B.C. Hydro defines the capability of the plant at 5520 GW.h (Exhibit 2, Testimony Mr. Spafford, p. 6). The boilers were originally designed and operated as dual fuel units firing both Bunker C fuel oil and natural gas with natural gas the primary fuel and fuel oil used as a supplementary fuel. Each unit produced high pressure steam to drive its own steam turbine generator (Exhibit 4, GVRD 74 pp. 17, 18). Four turbines are capable of being decoupled from the generators to be used as synchronous condensors. In this capacity they are used for voltage control in the Lower Mainland.

In 1978 the pollution permits denied the use of fuel oil and the plant now uses only natural gas (T.Vol. 17, p. 2452).

The plant has three basic boiler designs: units 2 and 3 have limited oil burning capability; units 1, 4, and 5 have oil burning capability extended by adding flue gas recirculation; and unit 6, came with a guarantee on stack emissions, have gas recirculation added to the windboxes and is fitted with overfire air ports.

In response to a 1985 permit condition B.C. Hydro conducted a study (by Dr. F. Murray, October, 1988) to investigate ways to reduce NO_X emissions by modifying operating procedures. B.C. Hydro was able to demonstrate NO_X reductions of approximately 40 percent in all boilers by employing operating modifications (i.e. reducing oxygen in the flue gas and by varying the fuel staging) (Exhibit 4, GVRD 74, p. 103 , Dr. Murray's report of December, 1989).

This 40 percent reduction level corresponds to 75 ppm of NO_X for units 1, 2 and 3, 80 ppm for units 4 and 5, and 55 ppm. for unit 6 with all units rated at full load (Exhibit 5, BCUC Information Request 8.1, comments by Environment Canada). It should also be noted that B.C. Hydro conducted further experiments to determine the possible NO_X reduction at varying loads and was able to achieve a maximum NO_X reduction to 19 ppm at 60 percent of rated output on unit 6 and from 34 ppm to 69 ppm on units 1-5 (Exhibit 4 GVRD 74, p. 127, and Appendix B).

(b) <u>Role of the Plant</u>

The role of Burrard in B.C. Hydro's system is to:

(i) Supply emergency generation capability close to the system load centre during transmission outages, storms, etc.

(ii) Provide a source of electricity if major new projects are delayed.

(iii) Back-up B.C. Hydro's hydroelectric generating resources in low water years.

(iv) Provide voltage support for the Lower Mainland area.

(v) Firm up energy export contracts, whether or not it actually contributes to export energy.

With regard to the last role, the availability of low cost gas in the summer season, and the low level of domestic load at that time, leads to increased probability that in low water years, Burrard summer generation supports exports either directly or indirectly through reservoir conservation. Conversely, in high water years, there will be little likelihood of Burrard running for either export or domestic demand.

Burrard's actual energy production, since 1985, in MW.h, per calendar year has been:

1985	102	
1986	1,177	
1987	1,587	
1988	80,340	
1989	4,188,913	
1990	1,062,259	
1991	277,820	(for 9 months)

The production data serves to emphasize the variability in the use of Burrard that has characterized the role of this plant in B.C. Hydro dispatch decisions in recent years. Testimony by B.C. Hydro (T.Vol. 11, p. 1534) placed a base level of production at 600 GW.h per year, the amount used in part for such purposes as voltage support, system maintenance and standby capability. This level of operation is largely secured by firm gas contracts and would be required even in the highest water years. Beyond this base level, testimony by B.C. Hydro emphasized throughout the hearing that the decision to dispatch Burrard or any project depended on system optimization both technically and economically (T.Vol. 10, p. 1341). Assignment of Burrard to export in response to NEB requirements was undertaken retroactively, and in consideration of its "highest cost" ranking among the available generation facilities (T.Vol. 8, p. 1129).

Burrard could be run on a contingency basis for reservoir conservation at a point early in the water year, only to find as the season progressed that it had been unnecessary. This form of *unavoidable* surplus created by unforeseeable variability in water supply also creates a *use* of Burrard for export. It should be noted that particularly during the section of the hearings that considered environmental effects, B.C. Hydro emphasized that (a) if operation of Burrard did not achieve at least a 0.5 cents/kW.h margin (revenue minus incremental operating cost) the plant would generally not be operated; (b) if meteorological conditions indicated a potential for adverse impacts then the facility would not be used.

In view of the foregoing complexities, the Commission observes the following:

(i) Currently Burrard plays a vital system role in backup and voltage control necessitating its continued (domestic) use.

(ii) The level of analysis necessary to exactly determine Burrard's contribution to export is not available. Due to system complexity even the concurrent operation of Burrard while export is occurring may not mean that the plant is exclusively serving the export function.

(iii) Notwithstanding these observations, on economic grounds, the probability of Burrard being dispatched for export is greatest in the summer period when domestic demand for energy (both gas and electricity) is at a minimum, reservoir levels are falling, and natural gas for the plant is at its least cost.

Based on these observations, the Commission is forced to focus on the totality of environmental effects of Burrard in the first instance. Assurance is *first* established on an overall basis that the "*operating practices are adequate to mitigate any unacceptable impacts*" as expressed in the Terms of Reference. Then employing a prudent approach, any fraction of the actual operation from zero to 100 percent that actually can be attributed to export will also have been covered under the same prudent approach.

In response to Term of Reference 6(a) to "conduct a review of the role of the Burrard Thermal Generating Station in serving the export market" the Commission concludes that the role of Burrard in export is highly variable, a complex function of dispatch decisions based on water supply, economic advantage of the sale, the availability and cost of the gas fuel supply and technical operational considerations. Any assessment of adverse environmental effects arising from exports, therefore, entails an assessment of the total use to which Burrard is put.

6.1.2 Environmental Impacts Related to Burrard

The impacts of concern are derived solely from emissions of nitrous oxides, predominantly nitric oxide, NO, at the point of release.[1]

(a) Ozone Formation

The emission of concern, NO_X, provides a largely indirect pollution problem. A complex chemical reaction sequence involving reactive Volatile Organic Compounds ("VOC") and NO_X leads ultimately to elevated levels of tropospheric (ground level) ozone. Both heat (temperatures of 25°C or more) and light (UV irradiance) are required to promote these processes at rates that lead to elevated ozone levels. Burrard is not the sole source of NO_X. The release of NO_X by automobiles and other mobile sources and other industrial point sources in the urban airshed is well understood. Finally the time-base of the ozone production is such that it can rise to maximal levels at distances greater than 50 km down-wind from the urban sources, and up to several days after initial release of the precursors (VOC and NO_X).

(b) Nitrogen Dioxide

Nitrogen dioxide itself, through eventual acid deposition and through its health effects on sensitive individuals is itself an undesirable pollutant (Exhibit 2, Burrard Utilization Study, Air Quality Overview).

Canada is a signatory to the United Nations ("UN") Economic Commission for Europe ("ECE"), International Convention on Transboundary Air Pollution. In the Canadian Council of Ministers of the Environment ("CCME") Management Plan for NO_X and VOC, Exhibit 129, page 155, the international undertakings related to NO_X are given.

- a freeze in NO_X emissions at the 1987 level by December 31, 1994.
- national emission standards for new . . . sources . . . based on *best available technology economically feasible*.
- additional measures to reduce NO_X from existing stationary sources taking into account age, utilization and other factors.

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1 Other species nitrogen dioxide, NO_2, nitrous oxide N_2O are emitted. Nitric oxide is converted to NO_2 in the atmosphere.

These undertakings are independent of ozone generation. National Ambient Air Quality Objectives ("NAAQO") for nitrogen dioxide are given at the usual three levels: maximum desirable, maximum acceptable and maximum tolerable (Exhibit 132A, p. A3-3). For NO_2, these values are (annual mean) 32 ppb desirable and 50 ppb acceptable. While the annual GVRD measured values (A2-25) remain below 30, they are raised by relatively high monthly residential urban values in the *non-summer months* (A2-24, Exhibit 132A). As a result, control of NO_X sources outside of the summer months is an objective in its own right, quite apart from ozone formation.

(c) Other Pollutants

In respect of Burrard, the Commission can reasonably conclude based on waste management permits issued by the Waste Management Branch, Ministry of Environment and the GVRD District Director, and on actual levels of emissions and effluents reported to the NEB (Exhibit 122):

(i) Levels of air borne pollutants (specifically particulate, sulphur oxides) other than NO_X are acceptable.

(ii) Levels of water borne pollutants as specified in the permits and as actually measured are of no concern.

(d) Summary

The foregoing serves to introduce the critical questions that must be addressed in order to first understand the impact of Burrard emissions on the airshed and then to estimate the portion of that impact that can be allocated to exports.

(i) What overall limit on NO_X emissions is desirable on an annual basis?

(ii) What is the fractional impact of NO_X released by Burrard in creating exceedances of ozone beyond ambient air standards:

a) relative to the impacts of other NO_X sources in the airshed?

b) as a function of location relative to the Burrard site, and to the other sources?

(iii) If the contribution of Burrard to ozone formation can be identified, how significant are the effects of such ozone increments on the environment and on public health? Can the social cost of these effects be estimated?

(iv) Which periods of operation are critical in contributing to air quality problems and how are these related to export?

The next sections are intended to address these questions, beginning with the nature of the airshed, and then the impacts of the NO_X sources imbedded in it.

6.2 Characteristics of the Lower Mainland Airshed

The airshed, typically described as the LFV, is characterized by its location, topography and climatology. First it can be described as an urban area occurring at the entrance to a coastal valley, the upper reaches of which remain largely forested and agricultural. Further elements include the air funnelling effect of mountains on the north and south margins of the valley and the mediating effect of the off-shore land mass (Vancouver Island) on wind and precipitation. These features have been reviewed by Oke et al in Exhibit 132A, GVRD Air Management Plan Stage 1, Appendices A1-A4, Section A1-1 through A1-20 and references contained therein. Only a summary is provided here.

Further critical determinants of the airshed potential for pollution, are diurnal (daily) and annual variations in air mass movement both vertically, and horizontally. While local microclimatic effects modulate the main factors, the following observations can be made:

- In winter the area is subject to cool wet weather dominated by the flow of storms from the Pacific, cyclonic disturbances, with prevailing winds moving easterly up the valley. Incursions of arctic air with frigid conditions are exceptional. Lower average temperatures and lower irradiance (cloud cover) are experienced then, than in the fall and summer. These conditions serve to mitigate photochemically derived oxidants (i.e. tropospheric ozone). Higher precipitation than in summer removes pollutants more effectively from the air column.

- In summer and fall, the period of the year dominated by anti-cyclonic activity, climate is characterized by lower precipitation and moderate temperatures. Occasional high temperature episodes occur. The rain shadow effect of Vancouver island mountains creates "mild summer drought characteristic of a Mediterranean-type climate" (Exhibit 132A, page A1-1). Temperatures can exceed 27°C, typically for periods less than five days and no more than ten in the Vancouver city area. Summer temperatures beyond Abbotsford and in the upper reaches of the valley where ozone problems are experienced can exceed 35°C.

- Air movement is influenced by on shore marine flow year round. In the summer, the winds flow on shore and up the valley in the daytime, down the valley and off-shore at night, particularly during sunny weather periods of interest. During the day, a complex vertical air regime is established.

The on shore flow creates a phenomenon described as a Thermal Internal Boundary Layer ("TIBL") and an elevated temperature inversion. A similar reinforcing effect is established by the city acting as a heat island. The lower mixed layer defines the vertical distribution of pollutants that is observed. The product of mixing depth and the surface wind speed is regarded as an indicator for air pollution, low values suggesting high risk. The following observations are made:

(i) The mixing depth that is created is regarded as the limitation of the dispersion climatology of the area. It is thought to reach only 400-600 m at 25-30 kilometres from the coast. Much lower levels will be observed at the coastline where the mixing layer is initiated.

Notably Exhibit 132A, p. A1-4.

"In summer, Vancouver and Victoria together with cities on the East coast of Canada are likely to experience the lowest urban mixing depths in Canada."

(ii) Surface wind speeds are low in the LFV.

Notably, Exhibit 132A, p. A1-5.

"Southern British Columbia has the greatest frequency of light winds (< 3 m s-1) in Canada. Stations --- towards the east of Burrard Inlet exhibit unusually high frequencies with calm (20-43%)".

(iii) The reversal of winds at the surface occurs such that relative calm coincides with both the morning and evening rush hours (air flows up the valley in daytime, westward to the coast at night).

(iv) The reversal of winds has the quality of allowing pollution to be carried back to the city in the evening from the upper valley, only to be returned eastward in the next day's cycle.

A word of caution is needed. Further complexities are introduced in detailed analysis. Specifically, the mountains create a nighttime down slope flow of cold air leading to a valley inversion said to "*inhibit dispersion in low lying basins, eg. Port Moody/Ioco area*". Secondly, local winds can be set up by thermal microclimates. Examples are land-sea breezes, rural city border breezes and forest stand border breezes.

The question arises: Can the area be modelled meteorologically? Oke observes models have been successfully applied,

> " . . . capable of generating realistic estimates of both the spatial and temporal variability of the sea breeze including the horizontal fields of wind and temperature, vertical profiles of wind, the mixed layer depth and surface energy balance." (Steyn and McKendry, Exhibit 132A, p. A1-15)

As a reservation, it is stated that detailed knowledge of mixing depth and wind velocity in the LFV are not currently available (Oke loc cit A1-7). As well, B.C. Hydro observes, "...the lack of a valid wind field model for the region...that is for the LFV." (Exhibit 139, p. 2 L-4)

From the evidence it is clear that the LFV airshed has a high air pollution potential. The factors determining the potential are relatively well understood, and the area can be modelled, for example, to predict the wind fields that are present.

The major emphasis in controlling air pollution from NO_X derived ozone is on late spring and summer. Therefore, any controls that limit export generation from Burrard should focus on this period. Since low level ozone has been identified as the critical impact of NO_X affecting the environment and human health, emphasis will be placed in the remainder of the report on the May-September period. The Commission notes, however, NO_X reduction on a yearly basis contributes to a general improvement in environmental quality.

6.3 Ozone Levels in the Lower Fraser Valley

6.3.1 The Forecast of Ozone Levels

As stated in the introduction, the induction of low level ozone in urban airsheds involves a complex photochemical reaction sequence promoted by light and heat. The chemistry involves NO_X and a variable slate of organic precursors (reactive VOC) and tens of intermediate species. Some of the intermediates are also considered potentially harmful oxidants, notably peroxy acetylnitrate ("PAN"). Approaches to the control of low level ozone have, until recently, focused on reduction of VOC. As an illustration, the report "Clouds of Change", by the task force of that name (Exhibit 130), focuses on VOC, with less emphasis on NO_X. More recently, both the CCME through "Management Plan for Nitrogen Oxides (NO_X) and Volatile Organic Compounds (VOC)" (Exhibit 87) and the U.S. National Research Council Committee on Tropospheric Ozone Formation and Measurement through "Rethinking the Ozone Problem in Urban and Regional Air

Pollution" (cited in Exhibit 110 the evidence of D. Steyn), have recognized the need for NO_X control. Two themes dominate the discussion:

(i) VOC control has been difficult to achieve and document. The contribution of VOC is both anthropogenic (principally mobile sources) and biogenic (naturally occurring compounds released by vegetation).

(ii) The NO_X component may be the limiting reagent or species, not present in excess so that reducing its concentration lowers the capability of the chemical system as a whole to produce ozone.

It is critical to note that the chemical processes involved are largely free radical chain reactions. Such mechanisms involve interdependent steps, and are typically both critically dependent on concentrations, and prone to non-linear concentration changes. Familiar examples are combustion and explosions of all types. Not surprisingly, chemical modelling of the exact conditions that create rapidly spiking maximal concentrations is notoriously difficult. In the present air pollution context, the additional complexity of meteorological prediction is added. The corresponding maximum concentrations are exceedances of ambient air standards, particularly the *maximum acceptable level of 82 ppb* for ozone. A series of daily events in which these exceedances are monitored is regarded as an extended episode.

The evidence of Steyn (Exhibit 110) is noteworthy. He reviews the anti-cyclonic weather encountered in the summer period in the LFV, remarks on the associated local concentrations of ozone sufficiently high to create a public health concern, and then observes that the critical weather conditions develop gradually and cannot be controlled by short-term reduction regimes. The conclusion advanced is that the "*only successful means for episode control is through reduction of all summer time emissions*".

The Applicants have not contested the foregoing analysis, only the *exact* role of Burrard NO_X emissions in creating the maximal concentrations of ozone that are observed. The Applicants concur that Burrard releases 2-4 percent of total NO_X emissions in the GVRD when operating at near full load (5,270 GW.h per annum), and concede the probable direct ratio of these emissions with ozone productivity in the airshed, possibly as high as 5.5 percent in the critical summer period.[2] The unavailability of sufficiently accurate modelling to pinpoint the relationship of Burrard emissions to specific local concentrations is, however, repeatedly asserted by the Applicants

2 The Commission must stress that only a portion of the NOx and resulting ozone will be attributable to Burrard generation destined for export. As discussed in Section 6.1.1, that portion has a probability of being significant in the critical summer period under discussion.

(Section 6.3.2). The nature of appropriate regulatory regimes in the face of such uncertainty is addressed in Section 6.7.

6.3.2 Studies and Modelling Information on Air Quality in the Lower Fraser Valley

(a) Pre-requisites to Modelling

To establish and monitor progress in an air quality management plan, detailed information is required on sources of pollutants, their transformation and transport in the airshed and eventual clearance or disposal. Any variations in these inputs, changes and outputs that occur on a daily or seasonal basis as a result of source changes, meteorological effects or chemistry, are important in determining management regimes.

The Commission has been charged with consulting with the Ministry of Environment and the GVRD to ensure that such studies and the attendant modelling are adequate *specifically* for Burrard, as a source. The time available to the Commission, and the logistics of establishing the consultation mechanism, did not allow for the in-depth technical assessment of the current state of the information base that would be required to thoroughly address the Terms of Reference. The Commission notes that three elements are involved:

(i) The regional data base: meteorological, pollutant inventory, and monitoring results.

(ii) Regional modelling: the current state of the art and its application to the GVRD.

(iii) Imbedded point source modelling: available models and their application to Burrard, completed or planned.

(b) Modelling the Burrard Plume

The Commission notes that the GVRD Management Plan Stage 1 (Exhibit 132A) Appendix A-4 "Air Quality Modelling" presents a thorough review of the air modelling problem in the airshed. It begins with an assessment of the work done with the Empirical Kinetic Modelling Approach ("EKMA"), and the utility of the output. As required by the Terms of Reference given to BH Levelton, the report proceeds to review air models available in North America (September, 1989, A-4-4). the study then recommends that the Urban Airshed Model ("UAM") be adopted by the GVRD. The data inputs that are required for the UAM and other models are also presented in the Appendix. Finally, the report analyzes the resource requirements for implementing the UAM. In testimony, the GVRD did not elaborate on the status of the adoption of UAM, though in Exhibit 139, B.C. Hydro refers to the proposed UAM model for the GVRD.

> **The Commission recommends that the GVRD provide a report to the Minister on the status of the adoption of the UAM model.**

From the Applicants' submission (Exhibit 2, Tab 5, pp. 93-100) the Commission received a synopsis of the conservative tracer studies conducted on stack gas dispersion during 1979-82, and a review of the results of a concurrent application of the IMPACT model to Burrard. The Commission concludes that up-to-date information on the dispersion and ultimate impacts of the Burrard plume on the airshed are not avoidable.

> **The Commission recommends that the Applicants initiate such studies and modelling as are necessary to provide information on the separate effects of Burrard as an imbedded source within a Regional Oxidant Modelling ("ROM") exercise.**

> **Further, the Commission recommends that the Applicants pursue the point source modelling program for Burrard, in collaboration with the GVRD, federal and provincial agencies, to provide detailed information in a timetable parallel to the development of the Lower Fraser Valley data bases and regional modelling outputs.**

It is possible that the GVRD may consider requiring such information of all major existing point sources for NO_X and VOC as an adjunct to the issuance of Waste Management Permit renewals and in pursuit of the goals of the Air Quality Management Plan.

(c) Modelling Status

As the hearings proceeded, several exhibits were entered into evidence that shed light on the current state of air dispersion modelling in North America. Notable among these were a recently completed Wisconsin Electric Power Company ("WEPC") study of the Paris Generating Station, located in a non-attainment area in which the ozone problem is regional and widespread (Exhibit 114). The airshed characteristic involves transport of ozone and ozone precursors from upwind source regions, combined with local emissions, and the unique meteorology of the Lake Michigan area. The study, which predicts incremental ozone contributions from a 300 MW natural gas-fired facility with 25 ppm NO_X emissions could be fairly described as related to the problem posed in the

LFV. However, the available data base had significant advantages over the current situation in LFV and topographic constraints (other than a "Lake Effect") were less complex.

In response to a question from the Commission, the Applicants have commented on the success of the WEPC study (Exhibit 139). The Applicants point out that the Wisconsin study was built upon regional scale field studies and simulations which had been carried out for the Lake Michigan Ozone Study. In turn, input from the ROM was possible, providing initial and boundary conditions for a Reactive Plume Model calculation (i.e. a nested plume approach). The study, and indeed its apparent success, suggests that a similar exercise could be carried out in LFV, provided the following *components* were available.

"(i) Small-scale gridded emission inventory with appropriate temporal parameterization and chemical speciation.

(ii) Gridded regional ozone simulation model.

(iii) Locally representative wind field model, and other ancillary data, such as accurate mixing height data for an ozone episode day." (Exhibit 139)

The foregoing are direct quotations from the Applicant, B.C. Hydro (Exhibit 139), but are consistent with the thrust of information exercises and simulation feasibility studies mandated for the LFV under the CCME NO_X, VOC Management Plan (Exhibit 129).

The Commission is of the opinion that the Minister would be well served by a direct information request to the appropriate agencies which would reveal the current status of the studies in the NO_X, VOC Management Plan. These studies represent, in total, a well considered program, expertly conceived, both necessary and sufficient, when completed, to respond to Term of Reference 6(b) in respect of the *regional* data requirements.

The appropriate initiatives of the CCME, as described in the NO_X VOC Management Plan (Exhibit 129) are quoted as follows: (The designations S101, etc. refer to the CCME code.)

" <u>*Initiative S101*</u>

Streamline emission inventories with automated provincial reporting to establish a maximum one-year lag time by 1993.

<u>*Initiative S201*</u>

Analyze available ambient air monitoring data to obtain additional information on ozone episode characteristics.

<u>*Initiative S202*</u>

Expand the ambient monitoring network for NO_x and O_2 with emphasis on rural regional monitoring.

<u>*Initiative S203*</u>

Obtain better information on the transboundary flow of NOx, VOCs and ozone and on the transport of these pollutants in the various segments of the Lower Fraser Valley, Windsor-Quebec Corridor and Southern Atlantic Region.

<u>*Initiative S204*</u>

Prepare refined meteorological data sets for the Windsor-Quebec Corridor and Lower Fraser Valley with spatial resolution to facilitate oxidants modelling.

<u>*Initiative S205*</u>

Set up and run appropriate scale oxidants models for the Lower Fraser Valley and Windsor-Quebec Corridor, preferably with grid sizes for episode modelling not greater than 20 km x 20 km for rural areas and 5 km x 5 km for urban areas.

<u>*Initiative S206*</u>

Evaluate current information on health effects at difference ozone exposure concentrations and times, determine exposure levels in Canada and develop a position on a 6-8 hour standard for ozone exposure.

<u>*Initiative S207*</u>

Evaluate current information on ozone damage to vegetation and develop a position on the form and level of an ambient ozone standard to protect vegetation."

(All Exhibit 129)

As well, the Applicants have indicated further initiatives in progress (Exhibit 139) namely:

(i) Collaboration in the Canadian Electrical Association's project with Ontario Hydro to use ROM in a Reactive Plume Model analysis of the Nanticoke facility on Lake Erie.

It is not clear whether the intention is to attempt immediate translation of this exercise to Burrard.

(ii) Application of U.S. Environmental Protection Agency ("USEPA"), Rough Terrain Dynamic Model ("RTDM") or Complex Terrain Dynamic Model ("CTDM") models to investigate the NO_x concentration fields from Burrard to greater distances than previously attempted.

It should be observed that utility research continues in the modelling field. The Commission reviewed a recent study by Ontario Hydro (Exhibit 145). The subject was the Nanticoke Coal-Fired Power Plant on Lake Erie. The study focused on an exceedence episode involving the tracking of the plant plume north-easterly over north Hamilton and Toronto. Notably, this study suggests nitric oxide titration of ozone persists into the far field, in contrast to the WEPC study cited earlier.

The Commission notes that the U.S. National Research Council report by the Committee on Tropospheric Ozone Formation and Measurement (cited in Exhibit 110) also contains a succinct appraisal of the research needed to enhance the predictive capacity of air models.

6.4 The Regulation of Air Emissions in the Lower Fraser Valley

6.4.1 Air Quality Concerns

In order to respond to Term of Reference 6(b) that seeks to define the impacts of export generation on the airshed, it is necessary to examine the current air quality concerns and regulatory responses in the LFV region.

In current regulatory approaches to airshed management, the contribution of individual emission sources to a total inventory for each pollutant is determined. The amounts and spatial distribution of the sources are modelled to produce ambient air quality predictions for a range of meteorological conditions. A system is established for monitoring the actual values. Reduction of emissions are undertaken when ambient air objectives (or standards for the protection of the environment or human health) are exceeded. The area is described as being in *non-attainment* when one or more pollutants, are in excess of objectives on a recurrent or persistent basis. Under non-attainment conditions, the onus for limitations of continued or additional emission into the airshed may be placed largely on the pollution generator.

The foregoing general discussion is relevant to these proceedings. Evidence established the consensus position of the federal, provincial and local (GVRD) environmental agencies that chronic exceedances were consistent with non-attainment for low level ozone. Significantly the Commission heard evidence from a range of individuals and officials expressing concern and awareness if not anxiety over the air quality (see Chapter 2.0). The Commission received direct input from sessions held in Coquitlam (T.Vol. 6) and in Chilliwack (T.Vol. 7) providing anecdotal accounts of respiratory health problems particularly in the Fraser-Cheam Regional District. The commitment of the intervenors to improvement of air quality was clear, as was their appreciation of the nature of the problem.

It is beyond the scope of the Commission report to review in detail, the studies related to effects of ozone on human health, forest lands, and agricultural production. The Applicants have addressed these issues (Exhibit 2, Testimony of Dr. Caton, Burrard Thermal Utilization Study Air Quality Overview, Sections 5.0 and 6.0). The Commission noted the final statement by the Applicants in Section 5.0 on health effects:

> "The present Canadian Maximum Acceptable Objective for ozone exposure of 0.08 ppm for one hour is at the level shown to induce adverse effects in normal subjects if moderately heavy exercise is being undertaken. Such a level might increase the response of asthmatic subjects to allergens in their environment. There is, therefore, every reason to stress that this standard should not be exceeded if public health is to be protected."

The summary of current research and potential effects on vegetation provided in Section 6.0 was informative. Once again attention is drawn to the final summary paragraph:

> "As a result of these analyses, it can be stated with some certainty that the O_3 levels experienced in recent years in the Lower Mainland have caused crop losses and have caused adverse effects in the local forests. In the latter context, it should be noted that the yield losses estimated for sensitive agricultural species at GVRD station T25 (Seymour Falls) range from 6% to 11%. Overall, there is some reason to believe that in some locations the agricultural losses may have exceeded 10%. The agricultural regions that appear to have been most severely affected are the easternmost parts of the valley."

These observations are in accord with the observations of other intervenors. Mayor John Les of Chilliwack, an area highly dependant on agriculture in its economic outlook, reported that the Ministry of Environment had estimated ozone created crop losses at $10 million per annum in the Fraser Valley (Exhibit 45). While clearly these losses are not attributable in more than a few percent to Burrard, the figure serves to underscore the economic effect of ambient ozone.

Finally, the Commission cannot ignore the aesthetic parameter, the quality of life associated with clear air, and its attendant scenic wonders in British Columbia, even while recognizing the small incremental contribution of the facility, when generating in support of exports.

6.4.2 Regulatory Response

Government response to the problem predates these hearings. First at the federal-provincial level, the CCME have confirmed non-attainment, and recommended a program of NO_X reduction for the LFV in "Management Plan for Nitrogen Oxides (NO_X) and Volatile Organic Compounds (VOC) (Phase I, November 1990; Exhibits 129 and 87, excerpts)". The management plan addresses other areas of the country, the Windsor-Quebec Corridor ("WQC") and the Southern Atlantic Region ("SAR") in addition to the LFV. Recommendations for NO_X reduction of about 40 percent are made.

In many jurisdictions where non-attainment areas for pollutants are present, new sources (and new uses of existing sources) are subject to restrictions that may exceed normal objectives in severity. The U.S. EPA has designated the approach as "*prevention of significant deterioration*" (cited in Exhibit 44A). For Burrard, the CCME report initiative N602 is particularly relevant in this regard.

> " *Initiative N602*
> *Region specific new source performance standards for fossil-fuelled power plants in the LFV and WQC, to be effective by 1995, specifying NO_X emission limits no greater than 200 ng of NO_2 per joule of useful energy output on a plant basis*."

Exhibit 129 is similarly relevant:

> "*Region specific existing source performance standards for fossil-fuelled power plants in the LFV and the Ontario portion of the WQC, to be effective in 1997, specifying NO_X emission limits of either (i) the 1995 NSPS ng/J of energy output limits for these regions or (ii) a combined T/yr and summertime T/day plant emission cap that will result in no greater annual or summertime daily emissions than the 1995 NSPS level*."

Largely in parallel with the federal-provincial initiative, and in close cooperation, the GVRD has initiated a detailed planning, monitoring and public education process to improve air quality. The program is summarized in a series of studies submitted as evidence to the Commission, namely Exhibits 132, 132A and 132B: GVRD Air Management Plan - Stage 1; Assessment of Current and Future Air Quality (September 1989) and Appendices A1-A4, and A-5: Current and Future emissions and Exhibits 89A and 89B; GVRD Air Quality Management Plan - Stage 2; Priority Emission Reduction Measures Draft Report and Appendix A, Point Sources.

6.4.3 Regulatory Complexities

The determination of technologies and operating practises at Burrard are made all the more complex by the following:

(i) The GVRD is currently conducting a review process for a new Air Quality Management Bylaw (Exhibit 136). This may lead to more stringent GVRD air quality permit standards (draft Bylaw, Exhibit 136, Tab 5).

(ii) A provincial legislative review is in progress on Environmental Assessment and Environmental Protection Acts. Extensive public consultation on pollution control standards and regulation is involved which may change the current GVRD mandate in waste management permitting, and the mechanism for addressing environmental impacts of energy removal.

(iii) The degree of consultation between the District Director and the Ministry of Environment in setting permit conditions under the Waste Management Act is not established clearly (J. McTaggert Cowan, Vol. 19, p. 2843).

(iv) The witness for the Secretariat of the Cabinet Committee on Crown Corporations suggested Crown Corporations may be joint applicants with respect to environmental regulatory processes, for example, B.C. Hydro and B.C. Transit (T.Vol. 21, p. 3422).

6.5 Burrard Role in Emissions

In the Terms of Reference, Clause 6(b) requires the Commission to:

> " . . . assess the impact on the Lower Mainland airshed, under various meteorological conditions of the air emissions which can be directly attributable to increased generation from Burrard to serve the export market".

It is essential to recognize that the Commission adopts the position that (i) the fraction of Burrard operation that is attributable to export in the summer months cannot be *precisely* determined; (ii) the fractional impact on the airshed from the emissions during operation of Burrard for whatever reason is not capable of being *absolutely* identified with the current information that is available; (iii) notwithstanding these caveats, the conclusion that Burrard does contribute to the air quality problem in the LFV to some degree, and that the operation of Burrard for export does occur to some degree in the summer months, are equally valid concurrent positions. The important elements of an assessment of the Burrard impacts, and inter alia responses to the questions posed in Section 6.1.2(d) are as follows:

(a) NO_X emissions from Burrard consequential to environmental impacts are nitrous oxides. Initially these are in the chemical form of NO, converted to nitrogen dioxide ("NO_2") as the (reactive) plume travels down wind and is integrated into the broader urban plume. Other embedded sources contribute in a similar fashion.

(b) Locally the nitric oxide from Burrard reacts with ozone to temporarily reduce ozone. However, the product of the reaction, nitrogen dioxide is a precursor for ozone formation, together with reactive VOC.

(c) The chemistry of the reactive plume from Burrard and the broader urban plume are complex, mediated by meteorological effects including temperature and irradiance as well as air mass movement.

(d) Inevitably, the down-wind or far field effect of the emission of NO_X from facilities such as Burrard into air masses containing anthropogenic and biogenic reactive hydrocarbons at the levels encountered in urban airsheds, is to elevate levels of tropospheric ozone relative to background levels (Exhibits 145, 114). During prolonged periods of inversion in the LFV, the lack of clearance of air pollutants from the airshed on a daily basis serves to enhance the effect.

(e) Under conditions of low winds, sunlight and warm temperatures encountered in the May through September period of "anticyclonic" activity, episodes of ambient air concentrations of ozone beyond maximum acceptable levels (82 ppb) can occur at levels causing immediate effects on the health of sensitive individuals.

(f) Only the <u>exact</u> nature of the conditions that precipitate these exceedances and the *precision* with which the time and location of the events can be predicted are in doubt. Significant progress in the modelling of the concentrations of ground level ozone in urban airsheds has been made. The current status of these models has been summarized in Section 6.3.2(c). Such models provide *increased* spatial and temporal resolution of episodes over current capability. The complexity of the chemical and physical problem suggests that absolute confidence in *predicting* events is unlikely to be achieved at a level that will offer sufficient public health protection by the simple mechanism of anticipating events and taking curtailment steps for NO_X emitters.

(g) NO_X from Burrard will, of necessity, contribute to ozone episodes, only the exact degree of that contribution at a given location under a given meteorology is undetermined. Incidents can occur when Burrard does not operate, but the inference that its operation would increase the frequency and severity of episodes is not statistically proven in view of the restricted data that is available.

These observations are essentially consistent with the recommendations of CCME and of the GVRD Air Quality Management Plan Stage 2 that a program of NO_X reduction be initiated to reduce levels of all airshed NO_X emissions by a significant percentage (40-50) in a short time, based on 1995 and 2005 targets. The Commission agrees that a *precautionary approach*[3] is called for in view of the non-attainment of the airshed in relation to ozone. Such an approach should require the reduction of NO_X emissions during the critical summer period.[4]

> **The Commission concludes that, to the extent that Burrard functions during this critical period, either directly for or in support of energy export, it will contribute to the probability of ozone episodes in the LFV non-attainment area.**

6.6 Burrard Pollution Control

6.6.1 History of Pollution Control at Burrard

There was a tendency of some intervenors during the hearings to describe the Burrard plant as being without pollution control or even, in the extreme, as a dirty plant. The Commission is persuaded that significant changes in operation, and other initiatives, have occurred over the lifetime of the plant so that a more balanced assessment of the record is warranted. The capability of further improvement being made, or the need to do so, is not diminished by recognizing the following:

(i) The 1978 decision to no longer use oil fuel.

(ii) The forty percent reduction in NO_X emissions that occurred through changes in combustion practise resulting from the work of Dr. Murray.

(iii) The provisions for reporting of:

- (a) operating schedules;
- (b) previous and following week schedules;
- (c) at the completion of the 1992/93 permit, a report on NO_X concentrations and discharge rates from all units; and
- (d) maintenance of a meteorological forecasting program.

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3 Such approaches are referred to as application of the "Precautionary Principle".

4 Other major point sources of NOx located in the GVRD such as the Tilbury and Lafarge Cement kilns also contribute to the problem. A program of NOx reduction for all sources in the LFV airshed is proposed in the GVRD Stage 2 plan. The mandate of the Commission is to consider Burrard, but it concurs with the contention that existing point source reductions should be initiated primarily because of their capability of improving air quality with maximum effectiveness, and not in respect of their private or public ownership (see Section 6.7).

(iv) Maintenance of an Emission Curtailment Plan including a provision for the District Director to order curtailment of Burrard based on exceedences of concentrations of designated air contaminants at air quality evaluation stations.[5]

(v) Restriction of operation, effectively a cap, as follows:

(a) to 6,000 m^3/min of exhaust gases, yearly average (full power 9,000 m^3/min) on each of six units; and

(b) to 8,000 m^3/min of exhaust gases, daily average.

(vi) In the 1989/91 permit a capping restriction of 1,900 kg NO_x per 10^6 m^3 of fuel gas.

The Commission notes the comment of Environment Canada (Exhibit 5, BCUC Information Request 8.1) that the Burrard plant already meets federal guidelines for *new and proposed* thermal generating plant, referenced in the Management Plan for NO_x and VOC's namely:

	Burrard	Existing Federal	Proposed Federal	
			1995	2000
		86 ng J^{-1}	50 ng J^{-1}	40 ng J^{-1}
Units 1,2,3	42 ng J^{-1}			
Units 4, 5	45 ng J^{-1}			
Unit 6	31 ng J^{-1}			

However, Dr. Berg, witness for the GVRD, pointed out that the system-wide value in Southern California Air Quality Management District ("SCAQMD") was to be reduced to 7 ng J^{-1} by December 31, 1999 (Exhibit 40).

6.6.2 The 1992/93 Permit

Considerable contention developed in the hearing over the extent and timetable for reduction of total NO_x emissions that should be adopted for Burrard. In synopsis, the GVRD proposal is to reduce NO_x emissions from natural gas-fired thermal power generating plants by 50 percent (of the 1990 value) by 1995, and by 70 percent by the year 2005, based on total tonnes emitted. For Burrard this formula approach translates to 1,100 tonnes per annum in 1995, and 660 tonnes per annum by the year 2005. At the outset of the Commission hearing, J. Barrie Mills, District Director, GVRD, formally stated the 50 percent reduction targets to B.C. Hydro in a letter to Mr. K. Epp dated April 1, 1992 (Exhibit 6). The reply from B.C. Hydro (Exhibit 7) proposed to undertake a voluntary reduction to 1,833 tonnes for the 1992 calendar year only. (Note: this is the erroneous

5 No curtailment provision is made in the 1991/94 Tilbury Cement Limited Waste Management Permit No. VA-175, though significant control measures were required as conditions for the permit (Exhibit 141).

1995 reduction target contained in the Stage 2 Air Quality Management Report Executive Summary. Exhibit 90, later corrected to *1,100 tonnes* by the GVRD, through Exhibits 99 and 135.)

Against this background, the Commission was presented with the issuance of a waste permit renewal for the operation of Burrard during the hearings (Exhibit 113). Specifically, under the authority of the District Director, it mandates the release of 170 mg/Nm^3 of NO_X at a total stack volume of 36,000 m^3/min of exhaust gases essentially a continuance of the conditions allowed under the previous permit. The period covered was April 30, 1992 through April 30, 1993.

One of the remaining conditions, submission of a plan for further NO_X control[6] by February 28, 1993, suggests that initiating planning for a control program might be sufficient to allow extension of the permit with the 170 mg Nm^3 standard. The Applicants have suggested a schedule for a retrofit program that could take up to six years to convert all the boiler units depending on the technology and implementation schedule chosen (T.Vol. 10, p. 1363). However, the Energy and Environmental Research Corp. ("EER") report prepared for GVRD and Environment Canada suggested a compressed program of 2-3 years would be possible.

6.6.3 Technological Changes Available to Burrard

The Commission sought a detailed analysis of the changes that would be required in operating practice or in retrofitting pollution control in order to meet more stringent NO_X emission standards. Cost and time required for construction were important considerations. Such information would provide the basis for estimating abatement costs, and indeed the feasibility, if any, of various NO_X reduction strategies.

No definitive position emerges from the record on this issue. Two circumstances apparently contributed to the situation:

(a) The inability of the Applicants to provide draft or provisional results of the Burrard Utilization Study (other than the Air Quality Review, R.B. Caton, Exhibit 2). The overall study was still in draft and destined for a public review process at the end of 1992, thus not

6 Further control measures are based on a target of 55 mg/m3, 29 ppm at 20°C and 1 atm (3% O_2), the permit conditions. The Commission believes this value to be equivalent to 27 ppm (3% O_2) at 0°C and 9 ppm at 0°C and 15% oxygen.

likely to be available in final form until early 1993 (T.Vol. 1, p. 150; T.Vol. 18, p. 2583). The Applicants maintained that it was premature to examine Burrard's operation prior to the study being available. Interim regulatory provisions could be required in the circumstances, and in fact, the term of the new Waste Management permit only extends to April 30, 1993. Both the costs and rank ordering of control strategies for Burrard were not fully clarified in the evidence, in spite of the extensive studies that B.C. Hydro has in hand (Exhibit 4, GVRD 74-1 of 153). Such as:

(i) Study of Methods of Reducing Nitrogen Oxide Emissions, August 1989.

(ii) Studies for Reduction of Nitrogen Oxides-Burrard Thermal Generating Plant, December 1989, F.E. Murrary, Ph.D.,P.Eng.

(b) Secondly, the Commission observed that Environment Canada and the Greater Vancouver Regional District had commissioned their own study, "Review of NO_X Reduction Technologies Applicable to B.C. Hydro's Burrard Thermal Plant", EER (Exhibit 5, BCUC Information Request 8.1, comments by Environment Canada).

The Commission was able to identify the principal retrofit and operating practise options available to the Applicants by examination of the B.C. Hydro and EER reports, both generally and in terms of specific technology.

In general, and as summarized by Environment Canada (Exhibit 5, BCUC Information Request 8.1) the main categories are:

- flue gas recirculation ("FGR").
- advanced burner and combustion modification techniques (low NO_X burners and gas reburn) for reducing the quantity of NO_X formed.
- reagent injection schemes for selectively destroying NO_X through non-catalytic reaction ("SNCR").
- add-on techniques for destroying NOx by injecting reagents (ammonia) and passing the flue gas across a catalyst (SCR).

Environment Canada selected four options for economic assessment, namely: Construction Modification or Flue Gas Recirculation; Advanced Burner Modifications [the Mitsubishi Advanced Combustion Technology ("MACT")]; Selective Non-Catalytic Reduction; and Selective Catalytic Reduction. B.C. Hydro, in the internal report by Cowley and deLeeuw, as requested by the GVRD, Question 74, Exhibit 4, add Pollution Minimization ("PM") technology also developed by Mitsubishi. This technology employs a post-firing methane injection approach.

As shown in Table 6.1, the projected efficiencies in reducing NO_X are in broad agreement between the two studies. In reading Table 6.1, it is important to note that the cost estimates relate only to the referenced sources, and are not current in the Applicants' view. Moreover, the starred (*) entries for B.C. Hydro are referred to in the report as achieving 25 ppm *as an expected maximum* NO_X *concentration-installed system*. The report makes clear that 25 ppm is an objective, or target level, not the lowest achievable emission rate ("LAER"). The report notes that the most severe regulation among German, Japanese and North American jurisdictions is 67 ppm, and the *target value* of 25 ppm therefore, seems somewhat severe. The text also makes clear that SCR would provide for further proven reduction, presumably to the technology capability level shown in Table 6.1, if required by the regulatory agency.

The value of 29 ppm requested by the District Director may not necessarily be the lowest achievable emission level. It does not require state of the art control technology (SCR) for its achievement. MACT, rated as 15-30 ppm, in combination with derating, could reduce daily or yearly cap values to relatively low levels without the necessity of the more expensive SCR technology.

The Commission observes that collaboration among the parties to take full advantage of the information available to B.C. Hydro on the one hand and GVRD/Environment Canada/Ministry of Environment on the other would be advantageous to the public interest.

6.7 Evaluation of NOx Emission Control Options

6.7.1 Application of Best Available Control Technology ("BACT")

The concept of BACT was widely used in the hearings, most frequently by public officials to describe control systems that would achieve the LAER for NO_X per GW.h output, usually SCR. For example, the City of Vancouver speaks of "going on record as requesting the immediate upgrade of emissions control at Burrard Thermal Plant to ensure that the Best Available Control Technology is being utilized" (Exhibit 86). For the Regional District of Fraser Cheam, Dr. Peter Cave described BACT as "8 ppm at 3 percent O_2", clearly the value associated with SCR technology (see Section 6.6.3 above). In Exhibit 39 he also suggests a willingness to entertain new thermal generating plants that met BACT (8 ppm emissions) in order to avoid the building of

TABLE 6.1

ABATEMENT TECHNOLOGY CAPABILITY
FOR GAS-FIRED POWER PLANTS

Technology	NO_X Limit (B.C. Hydro Study) [1] ppm	NO_X Limit (EER) [2] ppm	Cost Estimates (B.C. Hydro Study)	(EER)
FGR	Units 1 -5 60-70 Unit 6 55	60	13.0 M	8.7M
PM	35-50	—	41.2 M	—
MACT	15-30	30	44.9 M	60.0M
SCR with FGR	*Units 1-5 [3] 12-14 *Unit 6 11	—	77.9 M	—
SCR	—	11-16	—	70.8 M
SCR with PM	*7 - 10 ppm [3]	—	97.0 M	—
SNCR	—	50	—	16.1 M

1 From Exhibit 4, GVRD Question 74, 1 of 153. B.C. Hydro Study of Methods of Reducing Nitrogen Oxide Emissions.

2 From Exhibit 5, BCUC Information Request 8.1 (comments by Environment Canada), Review of NOx Reduction Technologies Applicable to B.C. Hydro's Burrard Thermal Plant, Energy and Environmental Research Corp, Irvine California.

3. 25 ppm NO_X provided as the "expected maximum NO_X concentration-installed system".

KEY

FGR	=	Flue Gas Recirculation
PM	=	Pollution Minimization (Mitsubishi)
MACT	=	Mitsubishi Advanced Combustion Technology
SCR	=	Selective Catalytic Reduction
SNCR	=	Selective Non-Catalytic Reduction

new transmission lines. The link between BACT and SCR was apparently reinforced by the evidence of Robert Smith, Administrator Air Quality Control in the Air Quality and Source Control Department of the GVRD who stated:

> "The District Director has decided that the terms of any future permits will require B.C. Hydro to meet NOx emission levels consistent with the installation of best available control technology at Burrard Thermal.
>
> To achieve these levels B.C. Hydro will probably have to install selective catalytic reduction within a reasonable period of time." (Exhibit 98, p. 3)

Clearly, in the submission of the City of Richmond (Exhibit 147), and in his testimony, Alderman Sandberg reiterates that "we at the Board, are in favour of best available control technology on this plant and all the other plants on the Lower Mainland that have a significant impact on our airshed" (T.Vol. 20, p. 3033).

The approach being adopted in the Stage 2 Air Quality Management plan, in its draft form, as proposed by B.H. Levelton and Associates, consultants to the GVRD, is more complex. Mr. Wayne C. Edwards, for the GVRD, stated that the introduction of new technology to achieve the 50 percent reduction target will be conducted in three phases:

> "The emission reduction measures for a given source were classified in Phases A, B and C controls, which are defined as follows:
>
> Phase A • Best available technology (BACT), strategy or management practices that are currently in use elsewhere.
>
> Phase B • Advanced control technology considered best available control technology for similar but different source categories.
>
> Phase C • New technology which is currently under research and development.
>
> Since Phase A measures are currently available, implementation by the year 1995 is feasible, provided the cost effectiveness is favourable. Review of control measures was focused on Phase A best available control technologies in order to arrive at a maximum degree of reduction in emissions, taking into account factors such as cost effectiveness. This is consistent with the recently published BACT Policy and Procedure from B.C. Environment. For Phase B controls, field demonstrations for a particular emission source are still needed and therefore any implementation of Phase B controls is expected to be around 2005. Phase C controls are not examined in the present Study, but should be included in the GVRD Stage 3 Air Quality Management Plan." (Exhibit 99)

The Commission believes this evidence best summarizes the Stage 2 approach. Specifically, for Burrard, best available control technology *of the Phase B type* is considered to be SCR. However, in the Stage 2 report, the *Phase A technologies* are summarized as follows:

> "Locally, the B.C. Hydro Burrard Thermal Generating Plant is the only major natural gas-fired steam turbine electric power generating facility. NO_X is formed during gas combustion from the high temperature (> 2100 K) oxidation of nitrogen in the combustion air. This plant currently meets the proposed CCME 1995 New Source Performance Standard in the NO_X/VOC Management Plan. Several Phase A technologies could be used to reduce NO_X emissions, including flue gas recirculation, modified operating practices, staged combustion and low NO_X burners. Mitsubishi low NO_X burners, for example, have an estimated NO_X reduction efficiency of 50%. Implementation of this Phase A control measure could likely be accomplished before 1995.
>
> Further reduction could be achieved before 2005 by post-combustion control measures such as selective catalytic reduction (SCR). SCR technology is currently available with an estimated control efficiency of about 70%." (Exhibit 89A, p. 5-12 as quoted in Exhibit 99)

As has been noted, the District Director, by soliciting technology for Burrard in the current permit of about 29 ppm NO_X emissions, is actually pursuing the Phase A program, defining BACT as management practices for natural gas-fired thermal power generating plants that are in current use elsewhere.

In light of this analysis, the Commission clearly feels that indiscriminate use of the expression BACT without clear definition and careful assignment of context can be misleading. As could be anticipated, reference to the use of the term BACT in other jurisdictions and agencies also presents difficulties. For example, BACT is also mandated in Southern California Air Quality Management District (SCAQMD) Rule 1135 (Exhibit 41). The use of the term BACT likely refers to the Best Available Control Technology-Technological Feasible. This latter distinction is discussed by Mr. Sagert in annotation of the District of Coquitlam's submission Exhibit 44A, in reference to page 4. The annotations also provide the general USEPA definition of BACT. The Commission notes that Dr. Berg in his testimony on the SCAQMD, speaks of *ratcheting down* to the SCR value of 11.2 ppm at three percent O_2 by December 31, 1999 on a system wide basis. It is important to note the phasing-in aspect of BACT application that is occurring in the California jurisdiction.

Within B.C., it is instructive to consider the definition recently adopted by the Ministry of Environment (as an interim policy pending new legislation). The definition of BACT, description of its application in B.C., and a consultative process plan sheet for determining BACT technology for specific processes are included in "BACT Policy and Procedure", memorandum of the Ministry of Environment, January 14, 1992. The definition follows:

> "BACT, Best Available Control Technology, is defined as currently available state-of-the-art control technology which is proven to be successful in reducing a waste discharge and has been applied for at least one year in similar facilities in the Province or in other relevant jurisdictions. The "control technology" refers to all of the following: raw materials, fuels, process technology and pollution control equipment or devices used to minimize both generation and discharge of wastes." (Exhibit 92)

In testimony by Dr. J. McTaggert Cowan of the Ministry of Environment (Vol. 19, T. 2829), the application of the policy was clearly presented. In summary, BACT is to be used in establishing "Waste Discharge Criteria to update and replace the existing Pollution Control Objectives". These would be applied to all new sources, existing sources undergoing modifications, and then all existing sources in a phased-in manner. The Commission observes that the draft criterion being considered for the Province of B.C. is 9 ppm at 15 percent oxygen or 27 ppm at 3 percent oxygen for gas-fired thermal generating plants in excess of 100 MW (T.Vol 19, p. 2841).

The difficulty for the Commission in assessing the BACT approach in British Columbia stems from the period when discretion is given to Regional Environmental Protection Managers to use the old objectives except where they are obviously out of date. "In such cases the Regional Manager may propose a standard believed to comply with the BACT definition and to be protective of the receiving environment as determined by an environmental assessment." (Exhibit 92) Not only is such application discretionary, but the schedule for phasing in existing sources has not been established.

The Commission observes that the hearings are occurring in a time of transition in which the concept of BACT is being discussed in British Columbia, but is not firmly entrenched in regulatory practice.

6.7.2 Evaluation of BACT as a Policy Option in Environmental Regulation

In general terms, a working definition of BACT for discussion could be:

> "the technology, among all those market-ready technologies providing an identical service, that emits the least amount of pollutant per unit of service."[7]

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7 This narrow definition corresponds to what might be more properly referred to as Lowest Achievable Emission Rate ("LAER") technology. In the following discussion BACT is used even through in some instances LAER might be more appropriate.

The Commission learned through days of testimony that while the above summary definition of BACT may be a good starting point, there are many areas for disagreement with this definition:

- Does BACT imply (1) proven in a real-world application, (2) already available on the market, or (3) soon to be available on the market?
- Should the focus of BACT be on just one pollutant or on the total array of pollutants from a given technology?
- Should BACT be a technical term, or should it include socio-economic and environmental parameters.

Generally, the setting of environmental targets for aggregate and individual pollutants has used BACT term to find what might be referred to as the *upper bound of pollution reduction achievable with technology*. This is the pollution reduction that is possible by changing technologies but not changing the services they provide (i.e. no changes in the use rate of existing technologies and no changes in lifestyle).

BACT also provides an indication of the cost (total and marginal) of achieving the upper bound of pollution reduction achievable with technology. For example, to find the total cost of the GVRD plan to reduce NOx emissions by 50% one can add up the cost per unit of emission reduced (times the quantity reduced) for the total set of BACT applications to point and mobile sources throughout the GVRD. The Commission recognizes that the overall global target for NO_X emissions in the GVRD (LFV) represents a *bubble cap* or a fix on the upper limit of the capacity of the airshed to accommodate NO_X. Questions related to relative costs of different control measures, and indeed concepts such as tradable permits and *trade-offs* (i.e. in transit) become most pertinent when strict overall regional caps are imposed. One can also estimate a marginal cost curve by plotting the cost per unit of emission reduction for each BACT application (essentially vehicles and various point sources, such as Burrard, cement plants, refineries, etc.)

Finally, BACT has been offered as a means of estimating the cost of pollution. If society decides that emissions must be reduced by the amount that can be achieved by BACT, then the marginal cost of the emission reduction by the most expensive BACT indicates society's willingness to pay for the last unit of pollution reduction. Some have argued that the BACT regulation, determined in a well-informed decision making process, is an effective approximation to society's estimation of the marginal damages of pollution.[8]

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8 See the discussion in Chapter 7.0 on abatement cost and damage cost approaches to estimating the costs of pollution.

6.7.3 BACT and Cost-Effective Pollution Reduction

BACT provides important information on the marginal and total cost of achieving various levels of pollution reduction. This information may in turn guide society in finding that level of pollution reduction at which the marginal social benefits and marginal social costs of reducing pollution are estimated to be roughly balanced. Once society has made this determination, the next question is how should it achieve its pollution reduction target.

One approach to achieve pollution reduction targets is to require the implementation of best technology (BACT) in all applications, regardless of cost. This may seem especially justifiable if 100 percent penetration of this level of technology is shown to still not enable society to achieve its pollution reduction target. Thus, the argument can be made that society will have to at least require BACT in all cases and take even more stringent measures, perhaps involving changes in technology use, rates and changes in lifestyle.

The Commission heard evidence to suggest that there are at least three potential drawbacks to this approach.

(i) *There may be more cost-effective ways of achieving the emission reduction target than by investing in BACT at the advanced technology level*. If B.C. Hydro were required to invest in BACT at Burrard, and it turned out that the plant was only required occasionally over the next 10 years, the investment (about $100 million) would turn out to be extremely expensive per unit of pollution reduced. From a social point of view, it would not be a cost-effective investment relative to other options for pollution reduction.

(ii) *The application of BACT may lead to changes in the use of a plant that could be counter to the environmental objective*. Burrard's current role is to increase the firm energy capability of the B.C. Hydro system in low water years. However, a $100 million investment in BACT may require B.C. Hydro to reconsider the plant's role in its system. BACT may be implemented as part of an overall plant modernization and system re-optimization leading to use of the plant for *base* load. Alternative investments (e.g. combined cycle gas turbines outside the Lower Mainland) would take over the low water backup role. Ironically, a dramatic increase in the use rate of Burrard, even with BACT, could lead to higher emission levels than would have occurred if the plant had no BACT but was only used for ensuring firm energy capability in low water years.

(iii) *A BACT requirement for the purpose of achieving only one environmental objective may reduce the flexibility and increase the cost of meeting foreseeable future objectives*. For example, if SCR were chosen as BACT for Burrard, it would decrease the NOx emissions per kW.h. of electricity generated. However, it would not reduce the CO_2 emissions per kW.h. (or per unit of useful energy if the plant cogenerated both useful steam and electricity). The only currently feasible means of reducing CO_2 emissions is by converting the plant to combined cycle (to reduce emissions per unit of output electricity) or combined cycle with cogeneration of useful steam (to reduce emissions per unit of output energy). The investment in combined cycle would also reduce emissions of NOx per unit of electricity, the same objective as the BACT. However, if the objective is to reduce emissions from this specific location (because of ambient environmental conditions), the plant must be restricted from increasing its capability. This is because a combined cycle plant that consumed the same amount of natural gas would increase its capacity from 900 MW to about 1300 MW.

6.7.4 An Emissions Cap as Alternative to BACT

The Commission heard argument that the ERC should be limited to not allow any use of Burrard to produce electricity for export. The logic is that NO_x emissions are somehow more palatable if they are a necessary result of producing electricity for our domestic requirements.

The Commission does not accept the argument that prohibiting the use of Burrard in support of export is an effective means of achieving the environmental objective of improved air quality. Whether society receives export revenue or domestic electricity from the Burrard plant, it must still trade off the value of these benefits against the pollution costs from the plant's emissions.

The logical consequence of the above-described argument is that B.C. Hydro should be allowed to run the plant continuously as long as it produces only for the domestic market.

The Commission also heard argument that because B.C. Hydro is a crown corporation it should be required to meet more stringent pollution reduction targets than other emissions sources.

The Commission does not accept the argument that it is socially desirable that higher environmental standards be applied to crown corporations, thereby implying that lower standards be applied to private corporations.

However, in a transition period, in which society is setting new environmental targets intended to eventually be applied fairly to everyone, the Commission agrees that it is reasonable to ask crown corporations to play a leading role.

As described earlier, the Commission accepts the GVRD (and CCME) concerns for the airshed, and the advisability of the 50 percent NO_X reduction target for thermal generation point sources by the year 1995 relative to 1985. It accepts the premise that the target will be difficult to reach, even if 100 percent application of best technology could be achieved for NO_X sources in this short time-frame. The Commission is particularly concerned with the summer period and specifically with the potential for operation of Burrard for export at that time.

The Commission recommends that the Ministry of Energy strongly encourage (and work with) the GVRD and the Ministry of Environment to explore the efficacy of an emissions cap at Burrard instead of requiring a specific technology.

An emissions cap is a restriction on the output of NO_X emissions of Burrard. It may be annual, monthly, or daily. It makes no prescription about technology choices, or the proportion of reduced production thereby leaving the decision about technologies and use rates to B.C. Hydro. The logic is that the regulators should restrict themselves to making regulations that directly address the environmental objective without interfering in the decisions of the polluter to find the most cost-effective way of meeting the regulatory obligation.

6.8 Recommendations for Burrard Policies and Operation Practices with Special Reference to Export

(a) Background

In reviewing the record, the Commission was struck by the range of emission targets in tonnes of NO_X per year that have been cited in planning documents, the variety of forecast production levels for energy from Burrard, and the pattern of use of the facility in the last ten years. For example, neither the Stage 1 Air Quality Management Plan, nor the CCME NO_X - VOC Management Plan made provision originally for NO_X emissions from Burrard. The plant did not operate in 1985, the inventory base year. Inventories were adjusted by adding the 2200 tonnes Year One value in Stage 2 projections.

To add to the complexity, objectives in the air management plan are currently not incorporated in legislation. The Commission is then confronted with a significant range of inputs of NO_X from Burrard, all the way from the legally mandated levels of the waste management permit, through to the desired objectives shared by all three levels of government in achieving NO_X reduction. Numerical values illustrating these differences in emissions and projected energy output are given in Table 6.2.

At an average annual exhaust flow rate from Burrard of 36,000 m^3/min, the Commission notes that 29 ppm NO_X concentration corresponds to a yearly total of 1,041 tonnes of NO_X emissions and that the effect of SCR, at 11 ppm, would be equivalent to 400 tonnes of NO_X emissions. The *technical effect* of daily and yearly caps on *energy output* is difficult to gauge. As outlined earlier, B.C. Hydro has achieved much lower emission rates from Burrard at reduced energy output, derating the plant in effect. The changes in energy and emission rates are not directly proportional, i.e. emissions may drop faster than energy output. In Table 6.2, the effect on summer production has been estimated based simply on the average energy of 504 GW.h, and a *nominal* emission factor of 0.4 tonnes NO_X per GW.h.

The Commission notes that in the SCAQMD as presented by Dr. Berg (Exhibits 40, 41) it is more usual to express NO_X emission restrictions in terms of energy input or (net) energy output. The Waste Management Permit (1989) issued by the GVRD to B.C. Hydro had a restriction of 1,900 kg of NOx per million cubic metres of gas (energy input), on which overall emissions were based. The current 1992-93 permit has removed that provision leaving no energy based restrictions. The CCME projections for thermal power plant caps are also expressed in energy units (ng/J).

(b) Commission Recommendations

(i) The Commission has concluded that Burrard may be used in support of exports pursuant to this ERC, subject to the following restrictions on NO_X emissions:

The Commission recommends that a daily cap on NO_X emissions in tonnes be established for the period May through September, calculated on a yearly objective for NO_X emissions from Burrard.

TABLE 6.2

BURRARD THERMAL GENERATING STATION
ENERGY OUTPUT AND NO_X EMISSIONS

Operating Conditions [1]	GW.h per year	GW.h (average monthly)	NO_X (tonnes per year)	No_X (tonnes per day) (365 days/yr.)
GVRD Permit [2,3]	5,995	500	3,217	8.81
BCH (Annual Capability)	5,520	460	2,200	6.03
BCH (Adjusted Annual Capability)	5,270	439	2,100	5.78
BCH (5 summer month usage) [4] (Forecast)	6,048 (504 x 12) (Rate)	504 summer average	2,419 (Rate)	6.63 summer average
5 Month First Step Cap. [5] (2,200 tonnes/year summer rate)	Applied May-Sept.	460 summer average	2,200 [8] (Rate)	6.03 summer average
5 Month Second Step Cap.[6] (1,833 tonnes/year summer rate)	Applied May-Sept.	382 summer average	1,833 [8] (Rate)	5.02 summer average
Potential 5 Month Third StepTarget[7] (1,100 tonnes/year summer rate)	Applied May-Sept.	229 summer average	1,100 [8] (Rate)	3.02 summer average

NOTES

1 All calculations employ a nominal 0.4 tonnes NO_X/GW.h.

2 Average annual Volume flow rate 36,000 m^3/min, 170 mg/Nm^3, (89 ppm) unrestricted operation. Estimation of maximum energy output by B.C. Hydro at 75 percent of rated capacity for this flow rate equals 5,995 GW.h

3 Rated capacity at 912.5 MW, 24 hr., 365 days per year = 7,994 GW.h. This theoretical level would be achieved by unlimited operation (a flow rate of 9,000 m3 on all units).

4 In his testimony, Mr. Spafford, for the Applicant, suggested an average May-June output of 504 GW.h (Exhibit 2). At 8,000 m3 permitted output and 0.4 tonnes NO_X/kW.h presumably production could be as high as 666 GW.h (11.75 tonnes NO_X per 24 hour day).

5 Corresponds to current annual NOx emission in Stage 2 Air Quality Management Plan for Burrard.

6 Corresponds to the undertaking of B.C. Hydro (Exhibit 7) for the 1992/93 year.

7 Corresponds to projected 1995 emissions in Stage 2 Air Quality Management Plan for Burrard.

8 The annual objective from which the monthly energy maximum is calculated (the proposed summer cap). The total annual NOx will be greater, based on the amount allowed by the GVRD permit.

The Commission recommends that the daily summer cap be reduced in steps, consistent with the objectives that are proposed for NO_X reduction in the GVRD Stage 2 Air Quality Plan.

The Commission suggests that appropriate benchmarks for the first two steps, and the date of their implementation be as follows:

	Yearly Objective	**Daily Cap (tonnes NO_X)**
1993	**2,200 tonnes**	**6.03**
1994	**1,833 tonnes**	**5.02**

The next step may well be related to the 1995 Stage 2 Air Quality Management Plan objective, that is:

1995	**1,100 tonnes**	**3.02**

The financial implications of the 2,200 and 1833 tonnes benchmarks on average energy production during the summer period are addressed in Chapter 7.0. The Commission notes that constraining Burrard to a total of 917 tonnes of NO_X from May-September under the First Step cap, does not reduce the permitted yearly value substantially, yet achieves a 9 percent reduction in summer NO_X. The permitted yearly value of 2,783 tonnes compares with the current value of 3,217 tonnes. The former is *significantly* greater than the 2,200 tonnes per year on which the summer cap was based, and provided gas supplies can be secured in the Oct-May period at attractive prices, the economic impact could be substantially reduced. A constraint only on the period of low domestic demand, May-September, should not affect security of supply.

Similar calculations with respect to the Second Step cap, which provides a 24 percent reduction in summer NO_X emissions, show a reduction in annual allowable NO_X to 2,640 tonnes compared with the 3,217 tonnes allowed under current permits.

(ii) The Commission further recommends that the foregoing restrictions be reviewed annually by the Ministry of Energy in consultation with the Ministry of Environment and the GVRD. This review should be performed in conjunction with annual reports on progress of the GVRD Stage 2 Air Quality Management Plan; and in collaboration with the Task Force cited in Recommendation (iii).

(iii) The Commission recommends that a joint Task Force involving B.C. Hydro, GVRD, the Ministry of Environment, the Ministry of Energy, and public representation be struck to consider the impacts of NO_X emissions on the LFV from Burrard on an ongoing basis. The Commission also recommends that the Task Force consider the results of the Burrard Thermal Utilization Study and, through a consensus process, develop a program for NO_X reduction from Burrard.

(iv) It is recommended that the Minister of Energy consult with the Minister of Environment on the status of ongoing studies initiated by the CCME to address information requirements and regional oxidant modelling for the Lower Fraser Valley. Studies would include, but not be limited to, Initiatives S. 201, S. 202, S. 203, S. 204, S. 205, S. 206 and S. 207.[9] Specifically, that the Minister confirm with the participating levels of government, which agencies or individuals are charged with Initiative S. 205:

> **"Set up and run appropriate scale oxidants models for the LFV and WQC preferably with grid sizes for episode modelling not greater than 20 km x 20 km for rural areas and 5 km x 5 km for urban areas.**
>
> **Environment Canada and the provinces of British Columbia, Ontario and Quebec reach agreement on the appropriate agencies to lead the modelling efforts in each region."**

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9 The designations S.201-S.207 refer to the CCME VOX NOx report. Details are provided in Section 6.3.2(c).

7.0 NET BENEFITS OF ELECTRICITY TRADE TO THE APPLICANTS AND TO THE PROVINCE

This chapter addresses the first item in the terms of reference:

> *The Commission shall review the Application and make an assessment of the net benefits to the Province and the Applicants of the proposed removals.*

The Applicants have provided the Commission with estimates of the net revenue to be gained from the export sale of interruptible and firm energy. They have also estimated financial benefits from export-related services such as equichange and storage. In addition they cite other benefits which are not quantified, such as improvement in system reliability. The Commission has been directed to review the net benefits claimed by the Applicants.

The Commission has also been directed to assess the net benefits that will accrue to the Province as a result of the proposed electricity trade. This requires a social benefit-cost analysis. This analysis will yield a different estimate of net benefits to the extent that trade results in gains or losses to parties other than B.C.Hydro. Thus the social benefit-cost analysis has a broader perspective than the private, or commercial, analysis that typically underlies business decisions. With respect to the proposed electricity exports the issue that has been posed for the Commission is whether environmental damage can be attributed to electricity trade, and, if so, whether in a social accounting the costs of environmental damage may negate the net benefits claimed by the Applicants.

Sections 7.1 through 7.3 of the present chapter deal with the net benefits that can be expected to accrue to the Applicants. In reviewing these commercial net benefits, three categories of export sales are distinguished: interruptible energy, firm energy sold under short-term contracts (up to three years), and firm energy sold under long-term contracts. These three categories are recognized in order to assess which costs are properly charged to electricity exports. Of particular concern is the contention of B.C. Hydro that exported electricity should be charged the short-run incremental cost associated with its generation. A further distinction is recognized between net benefits associated with export sales and benefits attributable to other aspects of energy trade.

Section 7.4 deals with consequences of energy trade that might be felt by others than the Applicants. This requires recognition of the costs and benefits of environmental effects that could, or might, be attributed to electricity exports. In particular, consideration is given to various methods that have been proposed for quantifying the costs of environmental damage. The focus is on NO_X

emissions from Burrard. Consideration is also given to the environmental costs of hydro system operation and to costs attributable to carbon emissions.

In Section 7.5 the Commission sets forth its analysis of net benefits to the Applicants and to the Province. Some adjustments are made to the net revenue figures presented by the Applicants, and account is taken of the principal social costs and benefits that would be felt by the Province. Modified analyses are presented to demonstrate the likely effect on net benefits from exports if the interim emissions restrictions recommended by the Commission for Burrard are put in place or if tighter emissions standards (related to mandated technology) are imposed. The Commission's conclusions regarding the net benefits of exports are set forth in a concluding section.

7.1 Net Revenue from Export Sales of Energy

7.1.1 B.C. Hydro Net Revenue Estimates and Critique

(a) Interruptible Energy

Table 7.1 provides a summary of B.C Hydro's projection of interruptible energy exports over five fiscal years commencing April 1, 1992, and ending March 31, 1997. Estimates of net export revenue do not include any deduction for the cost of incremental environmental effects. The projection assumes B.C. Hydro's proposed operating regime for Burrard (i.e., up to 5,270 GW.h per year) under the air emissions permit that existed prior to April 30, 1992.[1]

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 residual to hydro. These costs are deducted from export revenue at the Canadian border to determine the contribution margin and net revenue.

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1 Previous chapters have expressed monetary units of energy as cents per kW.h. As much of the evidence was expressed on a mills/kW.h basis, unit costs are referenced on this basis in this chapter. A mill is one-tenth of a cent.

Table 7.1

B.C. Hydro's Projection of Interruptible Energy Exports 1992-1997[2]

Item	1992/93	1993/94	1994/95	1995/96	1996/97	Average
Export Volume (GW.h)	2,850	3,250	2,840	3,000	3,000	2,988
Export Price (Mills/kW.h)	19.3	18.9	16.6	20.0	20.7	19.1
Average Incremental Cost (Mills/kW.h)	10.9	13.1	14.3	14.3	14.3	13.4
Contribution Margin (Mills/kW.h)	8.4	5.8	2.3	5.7	6.4	5.7
Net Export Revenue ($/Million)	23.8	19.0	6.5	17.2	19.1	17.1
Export Allocation of Generation (%)						
- Purchases	20	39	63	60	60	NA
- Burrard Thermal	57	61	37	40	40	NA
- Hydro	23	0	0	0	0	NA
Burrard Thermal's Contribution						
- Export Volume (GW.h)	1,623	1,980	1,065	1,200	1,200	1,414
- Incremental Cost (Mills/kW.h)	11.5	11.2	11.4	11.6	11.8	11.5
- Contribution Margin (Mills/kW.h)	7.8	7.7	5.2	8.4	8.9	7.7
- Net Export Revenue ($/Million)	12.7	15.2	5.5	10.1	10.7	10.9

2 Exhibit 5, BCUC Information Request #1.7. Years are fiscal years (April 1 - March 31); dollars in 1991 Canadian; Export prices are net at the Canadian border; incremental environmental costs are excluded; provision made for incremental Operating & Maintenance expense and transmission losses where appropriate; excludes incremental cost of wheeling within B.C.; values have been rounded.

A number of assumptions underlie the projections. Export prices are expected to average about 19 mills per kW.h (in constant 1991 dollars) and to remain fairly stable except for a slight dip in 1994/95. Incremental costs for each resource remain fairly steady in real terms (i.e., excluding inflation) over the projection period.[3] Average export volume for interruptible energy is projected at about 3,000 GW.h per year. The result is that net export revenue is estimated to average about 17 million dollars per year. The range in annual interruptible energy export volume extends from zero (very dry streamflow conditions) to 12,000 GW.h (very high water conditions). The corresponding range in net export revenue is, therefore, from zero to 68 million dollars per year, assuming the five-year average contribution margin of 5.7 mills per kW.h.

Upward and downward biases will affect the "average" and "range" projections of net export revenue. These are examined next.

(i) Upward Bias

The principal upward bias relates to the "one year hindsight" cost imputation method. If the imputation were done monthly as is the practice in reporting to the NEB, the net export revenue would probably increase significantly. This would result because a greater relative share of export volume would be imputed to the lower cost of hydro generation so long as there were months during the year without simultaneous exports and thermal generation (T.Vol. 11, pp. 1578-81; T.Vol. 9, pp. 1279-80).

The potential significance of this bias can be gauged by a comparison with the figures reported in BCUC Information Request 1.3 (Exhibit 5). Here the NEB month-by-month allocation scheme is used to estimate net export revenue for past interruptible energy sales. The average contribution margin (in nominal dollar terms) over the period April 1, 1987, to December 31, 1991, is about 11.4 mills per kW.h., according to the figures given in response to the BCUC.[4] This is significantly greater than the estimated contribution margin based on yearly allocations, which as noted above averaged 5.7 mills per kW.h over the period of the B.C. Hydro net revenue projections.

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3 Incremental costs for Purchases and Hydro are not included in Table 7.1. Incremental cost of Purchases is estimated at about 15.0 mills /kW.h and at 4.6 mills/kW.h for Hydro in 1992/93. Water rentals account for most of the incremental cost of Hydro, and are projected to increase 5.5% per annum in real terms.

4 The range in contribution margin was from 8.6 mills/kW.h (1989/90) to 13.2 mills/kW.h (1991/92).

The effect of relatively higher contribution margins related to interruptible export volumes of 3,000 GW.h (average) and 12,000 GW.h (upperbound) would be as follows:

Contribution Margin	Average Water (3,000 GW.h/yr.)	Very High Water[5] (12,000 GW.h/yr.)
	(Net Export Revenue/Year, millions)	
5.7 mills/kW.h	$17	$ 68
7 mills/kW.h	$21	$ 84
9 mills/kW.h	$27	$108
11 mills/kW.h	$33	$132
13 mills/kW.h	$39	$156

Other opportunities for higher net export revenue from interruptible sales include higher export prices and lower incremental costs. The evidence suggests these may not be strong possibilities, and hence the principal upward bias is likely to arise from the method of allocating export volumes to generation sources.

(ii) Downward Bias

Lower than average net export revenue from interruptible sales could arise from low water conditions, lower export prices, and higher than estimated incremental cost of gas supply at Burrard. Of these possibilities, the evidence suggests that higher than estimated cost of gas supply at Burrard is the most likely factor.

There are two methods for establishing the incremental cost of gas supply at Burrard. The first is the "Acquisition Cost Method", which relates principally to the commodity cost of the non-firm gas used (valley, swing or spot gas). The second is the "Gas Export Price Method" which is related to the price of interruptible gas exports from the province at approximately the same time period. In the case of interruptible energy exports, the Acquisition Cost Method may be conceptually preferable in that so long as there is a short term gas surplus, Burrard's gas use places no apparent constraint on gas exports and price data are not available for concurrent interruptible gas and electricity exports (i.e., there is about a three month lag on consolidated interruptible gas export prices; see T.Vol. 10, pp. 1340-43).

5 Net export revenue of about $109 million was estimated for 1987/88 with 9,323 GW.h, average prices of about 19 mills/kW.h, no volume attributed to Burrard Thermal, relatively low cost of purchases and a contribution margin of 11.7 mills/kW.h.

B.C. Hydro has estimated the acquisition cost of gas at about 11.3 mills/kW.h or about $1.00/GJ in real terms over the next five years.[6] This estimate reflects solely the expected cost of valley gas which has a planned energy capability of 2,940 GW.h per year. B.C. Hydro also notes that the cost of valley gas could range up to 14 mills/kW.h. The remaining 2,330 GW.h of planned capability is comprised of swing, spot, and firm gas. The evidence indicates that non-firm gas apart from valley gas may also contribute to export. Because it is not feasible to match dispatch decisions to export use, the extent of this possible contribution was not estimated by B.C. Hydro given the inherent difficulties of allocating supply between domestic (voltage stability, emergency, stream flow support) and export segments within the context of an integrated generation system.

The cost of swing gas appears to range between about 17 mills/kW.h and 20 mills/kW.h.[7] The acquisition cost of gas supply, for example, would increase by about 2 mills/kW.h (i.e., to 13.3 mills/kW.h) if an 80/20 mix of valley/swing gas was assumed;[8] which would reduce average net revenue by about 3 million dollars.

(iii) Net Effect of Biases

B.C. Hydro's one year hindsight allocation method results in a conservative estimate of net financial benefits, notwithstanding the possible underestimate related to the cost of gas supply. However, net financial benefits of interruptible energy exports will require re-assessment if Burrard's generation is substantially restricted in summer months or the plant is reconfigured following the Burrard Utilization Study.

(b) Short-Term Firm Energy (Contracts not Exceeding Three Years)

Table 7.2 provides a summary of B.C. Hydro's forecast of firm energy exports over the next five years. The projection assumes B.C. Hydro's proposed operating regime for Burrard. The estimation procedure is the same as for interruptible energy exports. Firm export volumes of 1,000 GW.h per year are projected, and incremental generation costs and attribution of export volumes to sources is treated just as in the interruptible energy export forecast of Table 7.1.

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6 Commodity cost of about $0.89/GJ, Westcoast Energy tolls of about $0.05/GJ and 6 percent Social Services Tax (T.Vol. 9, pp. 1269-70).

7 Range in commodity cost of swing gas is about from $1.40/GJ to $1.65/GJ, plus Westcoast tolls and SST; Burrard's efficiency is assumed at approximately 32 percent.

8 Further assumes valley gas cost at 12 mills/kW.h and swing gas cost at 18.5 mills/kW.h; these are median values of the estimated ranges.

Table 7.2

B.C. Hydro's Projection of Firm Energy Exports 1992 - 1997[9]

Item	1992/93	1993/94	1994/95	1995/96	1996/97	Average
Export Volume (GW.h)	1,000	1,000	1,000	1,000	1,000	1,000
Export Price (Mills/kW.h)	25.0	27.0	25.0	28.0	30.0	27.0
Average Incremental Cost (Mills/kW.h)	10.9	13.1	14.3	14.3	14.3	13.4
Contribution Margin (Mills/kW.h)	14.1	13.9	10.7	13.7	15.7	13.6
Net Export Revenue ($/Million)	14.1	13.9	10.7	13.7	15.7	13.6
Export Allocation of Generation (%)						
- Purchases	20	39	63	60	60	NA
- Burrard Thermal	57	61	37	40	40	NA
- Hydro	23	0	0	0	0	NA
Burrard Thermal's Contribution						
- Export Volume (GW.h)	570	609	375	400	400	471
- Incremental Cost (Mills/kW.h)	11.5	11.2	11.4	11.6	11.8	11.5
- Contribution Margin (Mills/kW.h)	13.5	15.8	13.6	16.4	18.2	15.4
- Net Export Revenue ($/Million)	7.7	9.6	5.1	6.6	7.3	7.3

9 Exhibit 5, BCUC Information Request #1.6. Years are fiscal years (April 1 - March 31); dollars in 1991 Canadian; Export prices are net at the Canadian border; incremental environmental costs are excluded; provision made for incremental Operating & Maintenance expense and transmission losses where appropriate; excludes incremental cost of wheeling within B.C.; values have been rounded.

Average net export revenue is projected at about 14 million dollars per year in real terms. The range in annual firm energy export volume is from zero (no firm surplus) to about 1000 GW.h, the latter figure reflecting the Commission's revised assessment of firm surplus in Chapter 3.0. The five-year average contribution margin is projected at 13.6 mills per kW.h.

(i) Upward Bias

The principal upward bias once again relates to the conservative "one year hindsight" allocation method relative to, say, a one month allocation procedure. BCUC Information Request 1.2 (Exhibit 5) applied a monthly allocation method which resulted in a contribution margin of about 17.4 mills/kW.h (in nominal dollar terms) for the April 1, 1987 to December 31, 1991 period. A contribution margin of, say, 18 mills/kW.h over the short term would result in average net export revenue of 18 million dollars per year (1,000 GW.h).

(ii) Downward Bias

Under B.C. Hydro's proposed operating regime for Burrard the principal downward bias relates to the cost of gas supply at Burrard. This was illustrated above in the discussion of interruptible exports by positing an 80/20 mix of valley to swing gas. This resulted in an increased gas acquisition cost of about 2 mills per kW.h. In addition, a portion of the BC Gas' transportation charge (e.g., 2.8 mills/kW.h or $0.25/GJ)[10] could arguably be included. BC Gas' transportation charge is similar in character to Westcoast tolls (which B.C. Hydro has included in the acquisition cost of valley gas) and if Burrard's domestic gas use is minimally at 20 PJ, then the transportation charge for incremental export use would be avoidable. If the cost of firm gas supply is increased by 4 mills/kW.h (i.e., to about 15.3 mills/kW.h), this would reduce average net export revenue by about 2 million dollars per year;

The Gas Export Price Method may have some conceptual merit for short-term firm sales. Exhibit 62 indicates that the weighted average gas export price at the B.C. border for the year ending October, 1990, was $1.86/GJ (about 21 mills/kW.h at Burrard's efficiency; incremental costs of gas production/transmission have not, however, been deducted) which indicates a higher gas value relative to the acquisition cost. However, with firm electricity exports limited to 36 months, an existing short term gas surplus and no apparent constraints on gas deliverability

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10 B.C. Gas' transportation charge of $0.25/GJ is part of a $5 million minimum take-or-pay charge (i.e., minimum take of 20 PJ).

related to Burrard, the Acquisition Cost Method is preferable at present for establishing the cost of gas supply.

(iii) Net Effect of Biases

A potentially stronger upward bias suggests that B.C. Hydro's estimates of net export revenue from short term firm electricity sales are likely to be conservative. Once again, these estimates would require re-assessment if Burrard operation were to be affected by output constraints or plant reconfiguration.

(c) Total Short-Term Energy Sales

The magnitude of the Applicants' estimates of the net revenue from all short -term energy exports can be gauged by summing the average of yearly values for interruptible and firm energy over the 5-year period described in Tables 7.1 and 7.2. The resulting amount is 30.7 million dollars per year.

7.1.2 Allocation of Net Revenue to Burrard

The five-year average of B.C. Hydro's estimates of net revenue from interruptible exports that can be attributed to Burrard is about 11 million dollars per year, as shown in Table 7.1. In response to a GVRD request, B.C. Hydro also applied an alternate method to estimate Burrard's contribution to interruptible energy exports, and this resulted in a net revenue estimate of about 10 million dollars per year (Exhibit 4, GVRD Information Requests 62 and 66). Both these estimates would be reduced if a monthly hindsight allocation method were used or if a portion of swing gas were attributed to export. The latter situation may be more likely to occur if Burrard operation were constrained in the summer months.

Table 7.2 shows B.C. Hydro's estimates of net revenue from firm energy exports that can be attributed to Burrard. The average of annual values under this proposed operating regime is around 7 million dollars. Again responding to the GVRD request, B.C. Hydro stated that an average premium of firm over interruptible energy sales of 8.5 mills per kW.h. could be applied to total firm exports in a given period to value Burrard's "firming" capability, the implication being that there would not be any firm exports without Burrard (T.Vol. 8, pp. 1055-58). This premium applied to an average annual level of firm exports of 1,000 GW.h, provides an alternative estimate of net revenue attributable to Burrard, specifically, 8.5 million dollars per year. As with interruptible exports, these estimates might have to be reduced to reflect a higher cost of gas supply, as could result from constraints on Burrard summer operation.

Taking the total of interruptible and firm energy exports, both of the Applicants' estimates attribute about 18 million dollars per year to Burrard, or on the order of 60 percent of the total net revenue generated by exports.

7.2. Other Benefits from Electricity Trade

In addition to net revenue to be obtained from export sales, the Applicants cited other benefits attributable to trade in electricity, some of which could be quantified and others of which could not. These other benefits did not draw much attention from Intervenors, who instead focused on effects related to electricity exports.

7.2.1 Coordination and Services

B.C. Hydro estimates the present value of economic benefits to the Non-Treaty Storage Agreement at over 100 million (1991) dollars. These benefits relate to improved operational flexibility, improved firm energy capability, and deferral of construction of new generating resources. This was said to be a "conservative" estimate, because it addressed only "firm energy gains and secondary energy losses associated with the agreement" (T.Vol. 11, pp. 1588-89). While testimony verified that this present value figure could be expressed as an annualized value the calculation was not provided. However, under reasonable assumptions this would be around 10 million dollars per year.[11]

The Applicants identify several other export-related benefits for which they provide dollar valuations. These included storage services for BPA at 3.5 million dollars per year and load factoring for TransAlta at 1.0 million dollars per year (T.Vol. 11, p. 1460). Another, though apparently with a less precise valuation, arises through coordination with Alberta, which has saved B.C. Hydro from installing an additional 400 megawatts of capacity. This benefit was valued at 12 million dollars per year (T.Vol. 11, pp. 1590-91).

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11 The evidence was unclear as to whether the $100 million present value estimate related to the remaining term of the Agreement (i.e.. about 11 years to 2003) or the full term of the Agreement. Average annual real values ranging from $9.4 million to $14.0 million are derived for 25 and 11-year terms respectively, for example, assuming an 8% real discount rate. Also see T.Vol. 11, pp. 1474-75.

The benefit figures described in this section yield an estimated total in excess of 25 million dollars per year.

Non-treaty storage	$10.0	million dollars per year
Storage and equichange	4.5	
Alberta coordination	12.0	
Total	$ 26.5	million dollars per year

7.2.2 Other Benefits

In connection with exports, the Applicants cited as an additional benefit the fact that the resulting U.S. dollar revenue stream permitted them to reduce the cost of hedging U.S. dollar debt repayments (T.Vol. 12, pp. 1729-30). Their rough estimate suggested this might represent a substantial financial benefit (T.Vol. 17, p. 2434). However, based on information on the record, the Commission does not feel justified in placing a specific value on this benefit.

The Applicants cited other benefits related to electricity trade to which they could attach no dollar value. There appears to be some overlap between these and the financial benefits described above. Other cited benefits were:

(i) enhancement of the value of TransAlta exports to the United States by shaping on the B.C. system (T.Vol. 11, p. 1522);

(ii improvement in system reliability (Exhibit 2, Tab 11, p. 11);

(iii) emergency support (e.g., earthquake, snow slide) (T.Vol. 11, p. 1593, and Vol. 12, pp. 1730-33);

7.3 Net Revenue from Longer-Term Contracts

In Chapter 3.0 a Commission recommendation stated in part:

> *Energy sales contracts longer than three years in duration should be referred to as long-term contracts because they will generally require additional investment commitments.*

In the preceding sections of this chapter the Commission has indicated its acceptance of the Applicant's position that the generation cost assessed against interruptible and short-term (less than three years) firm electricity exports should be short-run (avoidable) incremental cost. As indicated in B.C. Hydro's projections of "Est. Firm Demand, Firm Supply and Removable Energy Surplus (Exhibit 5, BCUC Information Request 3.1, attachment 1), during the term of the proposed ERC significant additions to energy supply are expected from two sources: IPPs and Resource Smart

("RS"). In addition, extra energy will be made available because of reduced domestic requirements due to self generation and Demand-Side Management ("DSM"). These sources, regardless of whether they are categorized as demand-side or supply-side, require investment that has not yet been committed (see Chapter 3.0). Where this investment could be avoided if not required to support exports, the exported electricity should bear some of the investment cost.

With regard to IPPs, appropriate costing can be explained with reference to two circumstances. Consider a natural gas fuelled thermal generating plant designed to supply export customers. If potential economies of scale exist, it would be attractive for the producer to secure a contract to supply B.C. Hydro in addition to contemplated export customers. Each customer would benefit from a larger plant to the extent that the average cost per kW.h would be lower. In this situation there would be no justification for designating B.C. Hydro or any other customer as being supplied from surplus capacity and hence profitably served at short-run incremental cost (i.e., essentially the price of the natural gas required per kW.h). Rather, some convention for allocation of fixed (investment) cost would be required.

On the other hand, situations could arise where *unplanned* surplus became available. For example, if the IPP, again with potential plant scale economies, foresaw expanding demand from its export customers it might choose to build ahead of that demand. Hence, until export quantities approached capacity utilization the IPP would have surplus energy. This would justify making energy available to B.C. Hydro at short-run incremental cost through the PEO, essentially the cost of the required natural gas. It would seem unlikely, though not impossible, that such energy would be available on a firm basis for a contract period longer than three years.

This example suggests that in a review of a proposed long-term (more than three years) export contract for firm energy the supply cost of energy to B.C. Hydro should be examined to determine whether short-run incremental cost or long-run (full average) incremental cost is appropriate.

7.4. Measurement of Environmental Costs and Benefits

7.4.1 Methodology

The environmental impacts that might be associated with energy trade have been examined in Chapters 5.0 and 6.0. Following the Terms of Reference, principal attention was paid to the emissions of the Burrard thermal generating station. However, potentially significant effects were identified by intervenors in connection with the operation of B.C. Hydro's hydro system for the generation and storage of energy. Concern was also expressed about the carbon emissions from thermal generating plants in any location.

If the net benefits of electricity trade for the Province—as distinct from the Applicants—are to be quantified, benefits and costs accruing to any and all citizens in the Province must be taken into account. The majority of the interventions received by the Commission dealt with costs resulting from environmental effects. The Commission heard considerable discussion as to the feasibility of quantifying various forms of environmental damage. This problem arises because for the most part environmental effects are what economists term "spillovers" - gains or losses that fall outside the market system. Adequate methods have not been developed for valuing these non-marketed losses or gains. The Commission heard conflicting views as to the appropriateness of alternative methods for obtaining quantitative measures of environmental effects that could be incorporated into a social benefit-cost analysis.

Two main approaches to quantification were presented: (a) direct or indirect estimation of damage costs, and (b) derivation of abatement cost. The first method relies on measurements of environmental damage, such as crop loss or increased incidence of disease (dosage-response); in the case of increased disease it would be necessary to devise a method for quantifying the value of human health, since it is not a marketed commodity. Indirect estimation of damage costs is illustrated by contingent valuation methods ("CVMs"), which utilize survey information on individuals' willingness to pay in order to place a value on, for example, a recreational activity such as fishing. The second method, calculation of abatement costs, values environmental damage at the cost that would be incurred to abate it.

As stated in Chapters 5.0 and 6.0, the Commission views the risks posed by certain environmental consequences of electricity generation and transmission as potentially serious. However, as will be explained, the Commission cannot accept any of the quantitative estimates of damage costs that have been presented as being sufficiently reliable to be commensurate with the commercial benefits and costs described in the preceding sections. Nevertheless, estimates of damage costs do lend emphasis to the potential significance of environmental effects, and estimates of abatement costs do provide an indication of the extent to which various measures that might be undertaken by B.C. Hydro would negate any commercial gains that might be achieved through electricity trade. Moreover, the Commission believes that in view of the research efforts now being directed at this problem it will in the future be possible to attach more weight in cents per kW.h to estimates of the environmental damage caused by electricity generation. Therefore, valuations of environmental effects proposed by the Applicants and several of the intervenors will be examined in succeeding sections. First, however, it may be helpful to briefly examine the assumptions that underlie the two main approaches to incorporating environmental damage explicitly into benefit-cost analysis.

The economic logic of pollution abatement is straightforward, if elusive in practice. The incremental value placed on damage reduction—that is, the benefit (lessened damage) associated with an incremental reduction in the emission of a pollutant—can be represented as the demand for environmental quality. Specification of this *demand* thus requires an estimate of the damage costs—crop losses, poorer recreational opportunities, etc. Abatement cost—the cost that must be incurred to achieve an incremental reduction in the particular emission—can be represented as the supply of environmental quality. This cost could result from the installation of control devices, changes in process technology, or a diminished level of operations. Specification of this *supply* thus requires an estimate of the relevant incremental abatement costs. In this logic, the optimal result occurs at just that level of emission where *supply equals demand*, that is, incremental benefit (reduced damage) equals incremental cost (abatement expenditure). Some substances are sufficiently hazardous, or long-lived, that a target of zero emissions is appropriate, which may mean that an activity can no longer proceed. On the other hand, many practices, such as the use of fossil fuels, are so central to current economic activity that zero emission of various substances is not a reasonable target. In these circumstances the economic logic just described is relevant.

To achieve the preferred, or optimum, emissions level it is necessary to have quantitative information specifying *both* the "demand" and "supply" sides. In other words, the net benefit of emissions reduction is tested in successive steps by comparing the incremental reduction in damage cost with the corresponding incremental abatement expenditure. Exclusive fixation on an abatement cost measure short circuits this process: it presupposes movement from an existing level of emissions to a particular target level. This target level, especially when imported from one region to another, may be higher or lower than is appropriate, given incremental damage and abatement costs. Another aspect of this is that abatement cost can only be said to be a surrogate for damage cost when the optimal level of emissions has already been established, that is, abatement has been carried out until its incremental cost equals the corresponding environmental benefit.

The procedures outlined by the Ministry of Environment (Exhibit 92) envisage a consultative process through which both "demand" and "supply" considerations will be taken into account in establishing the target level of emissions, and hence the required level of abatement. With the present state of knowledge this process cannot have the precision suggested by the intersection of demand and supply curves, but the underlying logic is not dissimilar. Of particular significance is the incremental nature of the process. It might be noted that the waste management permit granted by the GVRD on April 29, 1992, requires a plan for achieving target levels of *emission* *concentration* and hence does not deal with total emissions or the question of an appropriate target level for emissions (Exhibit 113, Schedule C, p. 3).

7.4.2 Social Net Benefits with Accounting for Burrard Emissions

(a) Accounting Methodologies

By far the bulk of environmental concern expressed before the Commission related to Burrard. This concern has been described and analyzed in Chapter 6.0. Here we review arguments presented to the Commission that addressed the problem of explicitly incorporating environmental considerations into the calculation of net benefits attributable to electricity exports.

As has already been emphasized, there is no clear-cut method for attributing electricity exports to particular generating sources. Furthermore,in the particular case of Burrard, as discussed in Chapter 6.0, models of air circulation and plume diffusion in their current state are inadequate to provide a certain linkage between NO_X emissions from Burrard and ozone formation in various locations in the Fraser Valley. Nevertheless, it is useful to examine what valuations of environmental effects might be appropriate to British Columbia by making reference to studies that have been carried out elsewhere.

Before considering measurement of the social cost of various pollutants, it is necessary to consider the relevance to the current proceedings of damage incurred outside British Columbia. Normal procedure in benefit-cost analysis is to identify the "referent group" - those who are deemed to be affected by the activity in question. While the Commission's terms of reference specify net benefits to B.C., some intervenors expressed concern over the global effects of greenhouse gases. Alternative definitions of the scope of environmental effects of thermal generation to be taken into account could include these: costs sustained in B.C. attributable to all emissions from Burrard; costs attributable to Burrard emissions and to emission of greenhouse gases from sources in any jurisdiction; and costs of all emissions anywhere (see Exhibit 66, p. 43). It is clear that the Commission must consider costs sustained in B.C. Furthermore, for the purposes of this application the Commission believes it appropriate to consider the effects of carbon (greenhouse) emissions in all affected jurisdictions. However, it is not feasible for the Commission to take into account the implications of this ERC for all emissions in all jurisdictions.

A wide range of estimates and opinions were presented regarding the social cost of NO_X emissions from Burrard. Discussion centred on two sets of estimates: the "Pace numbers," based on a costing of various types of environmental damage, and the "Schilberg numbers," derived from abatement cost. These numbers are reported in Table 7.3. for several pollutants. It is important to remember that the estimates based on damage costs will vary depending upon the particular region and the ambient level of pollution in that region. Hence the single set of Pace numbers cannot be expected to adequately measure the environmental effects of a given emission in any selected region. The estimates based on abatement cost will vary with these factors and also with the degree to which abatement must be carried out in order to eliminate the environmental damage; in practice this is interpreted to be the degree of abatement required to meet a mandated target level of emission. Again, while the Shilberg numbers are related to several specific regions, it cannot be assumed that any set of them will adequately reflect the effects of a given emission in another selected region.

To relate these social costs to kW.h of electricity generated by thermal plants it is necessary to multiply by the quantity of a particular pollutant produced per kW.h of electricity. Estimates of these emission rates are given in Table 7.4. The resulting estimates of the social cost per kW.h that might be applied to emissions from thermal plants are shown in Table 7.5 for Burrard and for plants in three other regions. The abatement cost measure for Burrard in this table is based on the Schilberg figure for California outside the SCAQMD.[12] As noted, the Pace number is not region specific. The Alberta and Pacific Northwest ("PNW") emission values have been adjusted to assume exclusively coal-fired generation. Table 7.4 indicates that of the listed pollutants, only NO_X and CO_2 are emitted in more than negligible amounts, and this is reflected in Table 7.5, which shows possible estimates of social cost expressed in mills per kW.h of electricity generated.

(b) Views of the Applicants and the GVRD on Social Costs

The wide range of views regarding the social value of NO_X emissions is indicated as follows:

Applicants

Applicants did not attempt to assess damage costs, but cited preference for the PACE value (T.Vol. 13, pp. 1791-92). Applicants estimated the capital cost of Burrard's abatement to SCR standard at between \$80-\$100 million or about 3.5-4.5 mills/kW.h (Exhibit 106) under average output.[13]

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12 This abatement cost ascribed to Burrard is about 2.5 times the level that the Applicants estimated for SCR retrofit under average output.

13 Under full output, the estimate was indicated at 2.1 cents/kW.h, and ultimately 2.8 cents/kW.h when residual (unabated) NOx was factored in (T.Vol. 22, pp. 3495-96).

TABLE 7.3

Social Cost of Selected Pollutants

(1990 $Cdn/kg)

	SO_2	NO_x	CO_2	Part.	CH_4	CO	VOC
Schilberg							
Outside California	1.367	3.690	0.020	–	0.519	0.076	0.902
California Outside SCAQMD	2.460	25.696	0.020	–	0.519	0.076	1.558
Inside SCAQMD	25.010	33.5	0.020	–	0.519	0.076	23.919
Pace	5.225	2.111	0.017	3.063	0.460	0.065	–

\+ Costs computed on the basis of 1989 U.S. inflation at 6.2 percent from U.S. CPI-U and Canadian-U.S. Exchange rate of 1.17 based on 1990 Bank of Canada Review.

Source: Exhibit 66, page 42.

TABLE 7.4

Emission Rates from Thermal Generation

(tonnes/Gwh)

	SO_2	NO_x	CO_2	Partic.	CH_4	CO	VOC's
California[1] - Oil & Gas	0.222	0.833	545	0.036	0.010	0.171	0.004
U.S. PNW[2] - Coal	6.150	3.580	1,129	0.210	0.010	0.960	0.030
Burrard[3] - Gas	0.006	0.400	600	0.007	0.013	0.206	0.012
Alberta							
- Gas	0.023	0.834	678	0.000	0.017	0.270	0.016
- Coal	2.800	1.900	1,007	0.759	0.005	0.854	0.016
- Weighted Average[4]	2.500	1.734	963	0.676	0.007	0.780	0.016

1 Assumes 11% oil and 89% gas production based on 1989 Pacific Gas & Electric experience. SO_2, NO_x, Particulate, CO and VOC from Ted Holcombe, Pacific Gas and Electric. CO_2 and CH_4 from emission factors.

2 Emissions from Boardman coal-fired thermal plant. SO_2, NO_x, and Particulate from Terry Warrell, Portland General Electric. CO_2, CH_4, CO and VOC from emission factors.

3 SO_2, NO_x, CO_2 and Particulate from Al Brotherston, B.C. Hydro. CH_4, CO and VOC from emission factors.

4 Assumes 86.8% coal and 13.2% gas production based on 1989 experience. SO_2 and NO_x from Energy Resources Conservation Board, **Alberta Electric Industry Annual Statistics, 1990**. CO_2, Particulate, CH_4, CO and VOC from emission factors.

Source: Exhibit 66, page 41.

TABLE 7.5

VALUE OF AIR EMISSIONS RELATED TO B.C. HYDRO EXPORTS[1]
(MILLS/KW.H, 1990 CDN. $)

POLLUTANTS	NO_X	CO_2	SO_2	OTHER	TOTAL
Abatement Cost (Schilberg)					
Burrard [1]	10.3	12.1	neg.	neg.	22.4
Alberta	7.0	20.1	3.8	neg.	30.9
California [2]	23.0	11.0	1.8	neg.	35.8
PNW [3]	13.2	22.6	8.4	neg.	44.3
Damage Cost (Pace)					
Burrard	0.84	10.0	neg.	neg.	10.9
Alberta [3]	4.0	17.1	14.6	2.4	38.1
California	1.8	9.1	1.2	0.1	12.1
PNW [3]	7.5	18.8	32.1	0.7	59.1

1 Burrard's abatement cost is based on California costs outside the SCAQMD.

2 California values assume 25 percent of generation is within the SCAQMD.

3 Alberta and PNW values pertain exclusively to coal.

Source: Derived from Exhibit 66, report by Marvin Shaffer & Associates.

Dr. Caton, Consultant to the Applicant

Dr. Caton indicated that the PACE (damage cost) value should be viewed as an upperbound value for Burrard and the LFV airshed (T.Vol. 17, pp. 2558-59; T.Vol 18, pp. 2700-2721-2). Dr. Caton also indicated the nature of the damage cost curve is one in which zero (or near zero) damage occurs up to a threshold point (which is not a single point as receptors have differing sensitivities), and increases sharply thereafter. He also stated that the LFV airshed crosses the threshold very infrequently, and, for the most part, is below the threshold (T.Vol 18, pp.2697-98, 2737-39).

Mr. Gibson on behalf of GVRD

Mr. Gibson noted that limitations on science and economics rendered the abatement cost method the only acceptable method, and that the 'highest' exhibited abatement cost (eg. at $33,500/tonne inside the SCAQMD) is the appropriate valuation basis (T.Vol. 23, pp. 3659-3705).

Because of the wide range in valuations of social cost (Table 7.3), the abatement cost and damage cost figures for NO_X that might be applied to Burrard output differ by a factor of twelve. As noted above, the wide range in estimated social cost may be related to different conditions between regions and, in the case of abatement costs, to different standards or technologies prescribed to meet selected targets. In any event, lacking any studies that might provide estimates of the social cost of NO_X emissions specific to the LFV, the Commission could only explore the implications of the widely ranging estimates shown in Table 7.5. This is done in Section 7.5 below.

Although concern about NO_X emissions dominated discussion of environmental problems, some intervenors drew attention to the greenhouse gases - in particular, CO_2 - that are emitted from thermal generating stations. Compared to NO_X, even greater uncertainty surrounds valuations of the social cost of carbon emissions. Indeed, here the Pace CO_2 number is not based on damage, but rather falls back on the abatement cost methodology (Exhibit 66, p. 25). In the absence of a coordinated strategy among jurisdictions to achieve abatement of CO_2 emissions the implications for Burrard operation are ambiguous. Referring to Table 7.5 (or 7.4), some observations are possible regarding electricity trade. Burrard exports to the U.S. PNW, for example, may displace generation from coal-fired plants that are much worse emitters of CO_2. On the other hand, export to California of Alberta electricity, generated by coal-fired plants, may increase CO_2 emissions. Exports from Alberta to the PNW or from Burrard to California would appear to have little effect on the overall balance.[14] The Commission concludes, therefore, that CO_2 emissions from Burrard are not a crucial concern with regard to this ERC.

7.4.3 Costs Related to Hydro Resources

Chapter 5.0 provided a review of environmental impacts of the operation of hydro generation facilities. Various possible forms of damage were related to fluctuations in reservoir levels and to downstream river flows. As noted in Chapter 5.0, the Applicants stated that any incremental effects that could be attributed to exports were small relative to overall system operation. In final argument, the Applicants stated that certain environmental benefits could be linked to exports, specifically, reduced risk of spill and the maintenance of higher reservoir levels. There is insufficient information in the record to permit the Commission to place even order-of-magnitude valuations on the various hydro system impacts that might be related to exports, some of which may be offsetting. Again following the "precautionary principle," the Commission made recommendations that would bring about more formal procedures for determining the severity of environmental damage and could lead to more formal regulation.

Although the Commission did not receive studies that might lead to quantitative evaluation of environmental damage caused by system operation, it did hear testimony about how such studies were being carried out in other jurisdictions (T.Vol. 4, pp. 482-503). Such studies would be useful, particularly when reviewing long-term commitments that the Applicants might undertake. However, the Commission does not believe incremental effects related to the proposed exports would significantly affect the net benefit calculations so long as the system is operated so as to minimize adverse effects.

7.5 Net Benefits to the Applicants and the Province

Section 7.1 summarized the projections of expected commercial benefits accruing to electricity exports as provided by the Applicants and discussed the apparent biases in these projections. Here, in Section 7.5.1 the Commission presents its analysis of the net benefits that may be expected from interruptible and firm energy exports. Some of the assumptions underlying the Applicants' analysis have been modified, as will be explained. In addition, in order to represent net benefits to the Province, adjustments have been made where certain social costs may differ from those of the Applicants. These adjustments, however, do not include an explicit costing of environmental

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14 If the avoided generation mix in the U.S. changes (eg. displacement of PNG gas-fired generation) then, of course, the net CO_2 impact will alter accordingly.

damage; this issue is dealt with by testing the financial (or market valued) net benefits against cost figures that have been proposed for the measurement of environmental damage. Inasmuch as the Commission is limited, both with respect to data and to modelling capability *vis a vis* B.C. Hydro's system operation, the analysis of the net benefits of export sales is presented as a single annualized value. As an indication of the range of possible net benefits, the value for average water conditions is supplemented by values for low and high streamflow.

The Commission has also prepared modified analyses in an attempt to show the likely consequences for net benefits of the proposed environmental restrictions. The first of these, described in Section 7.5.2, is the summer emission caps recommended in Chapter 6.0. Section 7.5.3 extends this analysis to show the implications of a cap that would restrict summer emissions to the rate prescribed in the most recent GVRD target for 1995. Finally, Section 7.5.4 describes the situation with regard to electricity exports in the event that a particular abatement technology (SCR) is installed at Burrard; evidence presented to the Commission suggests that the GVRD might mandate SCR during the term of the ERC.

7.5.1 Net Benefits to the Province with Current Mode of Operation

Table 7.6 shows the Commission's estimate of the flow of net benefits to be expected by the Province as a result of energy exports. Both firm and interruptible sales are included. The first estimates derived describe net benefits to the Applicants. These are then modified to provide a better indication of net (financial) benefits to the Province. Finally, the potential significance to the net benefit calculations of the inclusion of cost of non-marketed factors—specifically environmental quality—is tested.

The estimates shown in Table 7.6 rely heavily on the projections provided by B.C. Hydro that were discussed in Section 7.1. For example, the annual quantities of interruptible and firm energy under average water conditions approximate the average of the yearly values given in Exhibit 5, Response to BCUC Questions 1.6 and 1.7, respectively. While prices received apparently are relatively stable around a modest upward trend, the estimates of net benefits are very sensitive to the way in which costs are imputed. As previously discussed, B.C. Hydro's projected allocation of exported electricity to particular generating sources is done on a one year basis, and this has the effect of overstating the share of exports attributed to purchases of electricity and to Burrard generation. The Commission's estimate of annual benefits in the average, or base, case assumes an imputation of 25 percent of the quantity of interruptible and firm exports to hydro generation. This is more in accord with past experience which assumes a monthly allocation procedure (Exhibit 5, BCUC Information Requests 1.2, p. 2, and 1.3, p. 2). The relative attribution between purchases and

Burrard was made with reference to the B.C. Hydro forecast (Exhibit 5, BCUC Information Requests 1.6 and 1.7). The Commission adjusted the incremental cost figure for Burrard generation under average water conditions by adding 1.5 mills per kW.h, believing this to more closely reflect the full acquisition cost of natural gas.[15] The resulting estimate of average annual benefits (net revenue) accruing to B.C. Hydro is 35 million dollars.

A more complete picture of the potential for exports is obtained by taking account of the range of values that can occur with different water conditions, since B.C. Hydro operates what is essentially a system of hydro generation. This is done in Table 7.6, where in addition to average net revenue, values are given for high and low streamflow years. It should be noted that the base (average) case is a normal water year, not the average of high and low streamflows. In a high water year the volume of interruptible exports expands; also the contribution margin increases because a greater share of the blended cost is imputed to low cost hydro. Table 7.6 shows a three fold expansion of interruptible sales, and an overall net revenue of over 125 million dollars. Precedent for this volume of exports was set in fiscal year 1987-88, when interruptible sales amounted to over 9300 GW.h. Streamflow conditions can also depress revenues below the average value as shown in the table, since both export volumes and the contribution margin fall.

The Commission also estimated the net revenue that could reasonably be attributed to Burrard. In the base case, this was nearly 11 million dollars or about 30 percent of the net revenue generated by exports. However, the Commission regards this figure as at best a rough indicator because of the difficulty of allocating electricity exports among generating sources.

The Commission's estimates of net revenue from export sales as set out in Table 7.6 can be compared with estimates submitted by the Applicants and summarized earlier in Tables 7.1 and 7.2.

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15 Higher and lower relative values for the cost of gas supply are assumed under dry and wet streamflow conditions, respectively. With dry conditions, the share of swing gas is greater; under wet conditions , only valley gas would be applicable.

Table 7.6

Social Benefit–Cost Analysis of Energy Exports
Burrard Thermal with Current Mode of Operation
(Annual Values)

	Streamflow Conditions Low	Average	High
A. BC Hydro and Province			
Energy Export Volume (GW.h)			
Interruptible	500	**3,000**	9,000
Firm	500	**1,000**	1,000
Total	1,000	**4,000**	10,000
BC Hydro Net Revenue ($ Millions)			
Interruptible	$1.90	**$19.88**	$107.33
Firm	6.15	**15.13**	20.43
Total	8.05	**35.00**	127.75
Net Benefits to Province Excluding Environment ($ Millions)			
Interruptible	$1.90	**$23.84**	$147.76
Firm	6.15	**16.45**	24.92
Total	8.05	**40.29**	172.68
B. Burrard Thermal			
Generation Volume (GW.h)			
Interruptible Export	200	**1,000**	---
Firm Export	200	**333**	---
Domestic	5,100	**1,167**	500
Total	5,500	**2,500**	500
Net Export Revenue ($ Millions)			
Interruptible	$1.00	**$6.00**	NA
Firm	2.70	**4.83**	NA
Total	3.70	**10.83**	NA
C. Implicit Value of NO_X Curtailment			
NO_X "Export" Tonnes	160	**533**	NA
Burrard's Net Revenue/Tonne	$23,125	**$20,313**	NA
BC Hydro's Net Revenue/Tonne	50,312	**65,625**	NA
Province's Net Benefits/Tonne	50,312	**75,536**	NA

Table 7.6 Cont.
Principal Assumptions

	Streamflow Conditions Low	Average	High
Export Allocation			
Purchases	60.0%	**41.7%**	15.0%
Burrard	40.0%	**33.3%**	0.0%
Hydro	0.0%	**25.0%**	85.0%
Total	100.0%	**100.0%**	100.0%
Export Prices (Mills/KW.h)			
Interruptible	19.0	**19.0**	19.0
Firm	27.5	**27.5**	27.5
Incremental Costs – BC Hydro (Mills/KW.h)[1]			
Purchases	16.0	**16.0**	16.0
Burrard	14.0	**13.0**	11.5
Hydro	5.5	**5.5**	5.5
Incremental Costs – Province (Mills/KW.h)			
Purchases	16.0	**16.0**	16.0
Burrard	14.0	**13.0**	11.5
Hydro	0.214	**0.214**	0.214
Contribution Margins (Mills/KW.h)			
(a) BC Hydro			
Interruptible	3.800	**6.625**	11.925
Firm	12.300	**15.125**	20.425
Total	8.050	**8.750**	12.775
(b) Province			
Interruptible	3.800	**7.947**	16.418
Firm	12.300	**16.447**	24.918
Total	8.05	**10.072**	17.268
(c) Burrard Thermal			
Interruptible	5.000	**6.000**	NA
Firm	13.500	**14.500**	NA
Total	9.250	**8.125**	NA
NO_X Emission Rate (tonnes/GW.h)	0.40	**0.40**	0.40

[1] *Includes Operation, Maintenance & Administration at 0.2 Mills/KW.h for Burrard and Hydro, and 7% losses for Purchases and Hydro.*

ANNUAL NET EXPORT REVENUE: APPLICANT AND COMMISSION ESTIMATES

	B.C. Hydro System (excluding Burrard)	Burrard Thermal
	(Million; average water)	
Interruptible Energy Exports		
Applicants[1]	$17.1	$10.9
Commission	19.9	6.0
Firm Energy Exports		
Applicants[1]	$13.6	$7.3
Commission	15.1	4.8
Total Energy Exports		
Applicants	$30.7	$18.2
Commission	35.0	10.8

1 Average yearly value over five fiscal years beginning April, 1992.

The net benefits to the Province differ from those to B.C. Hydro. Staying at present with financial benefits (environmental costs are dealt with below), the most significant adjustment required to account for net provincial benefits relates to water rental fees. These are economic rents, on the assumption that given the existence of the hydro system, use of the water for power generation does not displace an alternative use. The rental fees received by the Province are not required to compensate the supplier of any service—they are simply transfers of a portion of potential B.C. Hydro net revenues to the Provincial government. Therefore, they must be included in an accounting of net financial benefits to the Province. This is done in Table 7.6 by the device of removing the water rental fees from the computation of real costs, thereby increasing what is referred to in the table as the contribution margin. The effect is significant: average net provincial benefits are estimated to exceed B.C. Hydro net revenue by slightly more that 5 million dollars per year. As might be expected, a substantial windfall accrues in the event of high streamflow conditions when hydro generation jumps in relative importance and exports expand.

While cognizant of the sensitivity of the net revenue and net benefit estimates to underlying assumptions, the Commission is persuaded that electricity exports of the magnitude contemplated under this ERC have the potential to generate substantial financial benefits.

7.5.2 Impact of Environmental Costs on Net Benefits

As was discussed in the preceding section the Commission concluded that figures advanced by various intervenors to describe the unit cost of environmental damage per unit of electricity output were not sufficiently substantiated to be incorporated into a formal benefit-cost analysis. However, it is possible to make some comparisons as to what damage cost figures would have to be to alter the foregoing analysis. This is done in Panel C of Table 7.6.

Panel C of Table 7.6 shows the tonnes of NO_X emitted corresponding to the amount of exported electricity attributed to Burrard in each of the cases described. These tonnage figures are computed using an emission rate of 0.40 tonnes of NO_X per GW.h of electricity output, a figure that represents the technology currently employed. Panel C of the table expresses the ratio of net revenue attributable to Burrard to tonnes of NO_X emitted. If the environmental damage cost for NO_X were in the vicinity of 20 thousand dollars per tonne, in the base case any net benefit to the Province of electricity exports from Burrard would be negated. This figure, however, must be treated with considerable caution, since it rests on the allocation of export electricity to Burrard, and repeated reference has been made to the difficulty of attributing electricity exports to particular sources on the B.C. Hydro system.

The range of environmental damage cost figures that have been advanced was illustrated in Table 7.3. The 20 thousand dollar per tonne "opportunity cost" figure is on the order of 10 times the Pace estimate for NO_X damage cost. On the other hand, it is comparable to one figure, the Schilberg "abatement cost" for "California Outside SCAQMD", a comparison suggested in evidence tendered to the Commission (Exhibit 66, p. 43). As has been described in Chapter 6.0, the dominant concern associated with NO_X emissions relates to their role in the formation of ozone, a phenomenon that occurs when temperatures reach levels that are only observed during the May to September period. This net benefit analysis, therefore, indicates one set of circumstances where environmental costs could offset the gains of electricity exports, that is, there would be no social net benefits. This arises during the summer period for that electricity attributed to Burrard generation and with the acceptance of the highest damage cost estimate discussed before the Commission. This latter figure assumes that the technology that would reduce NO_X emissions from thermal generating stations in the San Francisco Bay area to a level acceptable there is the appropriate technology for Burrard.

Some intervenors took the position that no exports should be permitted when there was simultaneous operation of Burrard. B.C. Hydro stated that this form of restriction had proved unworkable in the past inasmuch as the integrated nature of the system precluded real separation of Burrard's domestic and export roles. Denial of the ERC would be a possible but extreme response to this impasse. It would implicitly place a very high value on the cost of NO_X emissions. This is shown in Panel C of Table 7.6, which gives the ratio of total net revenue from exports to the tonnage of NO_X emissions resulting from that portion of Burrard operation attributed to exports. In the base (average) case this ratio is about 65 thousand dollars per tonne of NO_X. This figure is beyond the range of NO_X damage cost estimates presented to the Commission. If net benefits to the Province are considered, the figure is still higher, at over 75 thousand dollars.

As previously stated, the Commission does not believe that, in their present state of development, environmental damage cost figures are sufficiently reliable to incorporate into a formal social benefit-cost analysis. Also, in its own present analysis, the Commission recognizes the problem of allocating export electricity to its generation source. Nevertheless, there is evidence that brings into question the social net benefits of exports attributable to Burrard in certain circumstances, specifically, during the May through September period and with existing abatement technology. This reinforces the Commission's view of the need to resolve the nature of Burrard operation so that it is compatible with regional air quality goals.

While recognizing legitimate environmental concerns related to Burrard, the Commission did not find evidence to indicate that the inclusion of the cost of environmental damage in a social benefit cost analysis would justify denial of the ERC, which would be the only conclusive way to ensure that Burrard did not contribute to exports.

7.5.3 Net Benefits to the Province of Exports with Interim Emission Restrictions

In Chapter 6.0, the Commission, recognizing environmental risks associated with summer operation of Burrard in support of exports, recommended restrictions on the plant's operation. It was the Commission's intent to establish interim safeguards so that B.C. Hydro's operations could continue pending the completion of the Burrard Utilization Study and resolution of such matters as the abatement technology and operating procedures to be employed to enable B.C. Hydro to meet or exceed the targets of Stage 2 of the regional air quality plan. At the same time the Commission sought to allow B.C. Hydro as much flexibility as possible to optimize its system operation. It is not possible for the Commission to fully assess the effect of the recommended restrictions on the net benefits attainable by B.C. Hydro from electricity exports. This is because only with the use of B.C. Hydro's system model could one determine the best system response to any constraints that are imposed. However, it is possible to make some rough estimates of the losses that could occur because of the restrictions.

Tables 7.7 and 7.8 indicate the possible effects of the Commission-proposed two-step May through September emission caps.

(a) Step One Summer Constraint (1993)

Table 7.7 shows the likely effect of the step one (summer 1993) emission cap. This calculation assumes a maximum daily NO_X emission rate during the restricted months of 5.78 tonnes. This cap reflects the current NO_X emission *rate* of 2100 tonnes per year at a rated annual capability of 5,270 GW. h. With current technology this places a ceiling of 439 GW.h on Burrard's monthly capability in the summer months, so that its annual capability falls from 5,270 to 4,945 GW.h. This loss of surplus capability reduces the extent to which B.C. Hydro can supply firm power under short-term contract. In the case described in Table 7.7 it is assumed that firm export volume falls to 667 GW.h, some two-thirds of the amount in the base case of Table 7.6, and that the 333 GW.h lost can still be marketed as interruptible energy. The result for the average water year is an annual net revenue flow of about 32 million, compared with the 35 million dollar figure of the base case in Table 7.6. Thus imposition of the summer NO_X emissions cap costs B.C. Hydro about 3 million dollars per year. The net benefit to the Province falls by about the same amount.

Table 7.7

Social Benefit–Cost Analysis of Energy Exports
NO_x Emissions Cap Step I
(Annual Values)

	Streamflow Conditions		
	Low	Average	High
A. BC Hydro and Province			
Energy Export Volume (GW.h)			
Interruptible	667	**3,333**	9,333
Firm	333	**667**	667
Total	1,000	**4,000**	10,000
BC Hydro Net Revenue ($ Millions)			
Interruptible	$2.52	**$22.01**	$111.30
Firm	4.09	**10.07**	13.62
Total	6.61	**32.09**	124.92
Net Benefits to Province Excluding Environment ($ Millions)			
Interruptible	$2.52	**$26.42**	$153.23
Firm	4.09	**10.96**	16.62
Total	6.61	**37.37**	169.85
B. Burrard Thermal			
Generation Volume (GW.h)			
Interruptible Export	260	**1,082**	---
Firm Export	130	**217**	---
Domestic	4,800	**1,167**	500
Total	5,190	**2,466**	500
Net Export Revenue ($ Millions)			
Interruptible	$1.30	**$6.49**	NA
Firm	1.75	**3.14**	NA
Total	3.05	**9.63**	NA
C. Implicit Value of NO_x Curtailment			
NO_x "Export" Tonnes	156	**520**	NA
Burrard's Net Revenue/Tonne	$19,576	**$18,543**	NA
BC Hydro's Net Revenue/Tonne	42,375	**61,759**	NA
Province's Net Benefits/Tonne	42,375	**71,934**	NA

Table 7.7 Cont.
Principal Assumptions

	Streamflow Conditions Low	Average	High
Export Allocation			
Purchases	61.0%	42.5%	15.0%
Burrard	39.0%	32.5%	0.0%
Hydro	0.0%	25.0%	85.0%
Total	100.0%	100.0%	100.0%
Export Prices (Mills/KW.h)			
Interruptible	19.0	19.0	19.0
Firm	27.5	27.5	27.5
Incremental Costs – BC Hydro (Mills/KW.h)[1]			
Purchases	16.0	16.0	16.0
Burrard	14.0	13.0	11.5
Hydro	5.5	5.5	5.5
Incremental Costs – Province (Mills/KW.h)			
Purchases	16.0	16.0	16.0
Burrard	14.0	13.0	11.5
Hydro	0.214	0.214	0.214
Contribution Margins (Mills/KW.h)			
(a) BC Hydro			
Interruptible	3.780	6.604	11.925
Firm	12.280	15.104	20.425
Total	6.611	8.021	12.492
(b) Province			
Interruptible	3.780	7.925	16.418
Firm	12.280	16.425	24.918
Total	6.6105	9.3428	16.985
(c) Burrard Thermal			
Interruptible	5.000	6.000	NA
Firm	13.500	14.500	NA
Total	7.831	7.417	NA
NO_X Emission Rate (tonnes/GW.h)	0.40	0.40	0.40

[1] *Includes Operation, Maintenance & Administration at 0.2 Mills/KW.h for Burrard and Hydro, and 7% losses for Purchases and Hydro.*

Table 7.8

Social Benefit–Cost Analysis of Energy Exports
NO_x Emissions Cap Step II
(Annual Values)

	Streamflow Conditions		
	Low	Average	High
A. BC Hydro and Province			
Energy Export Volume (GW.h)			
Interruptible	800	**3,600**	9,600
Firm	200	**400**	400
Total	1,000	**4,000**	10,000
BC Hydro Net Revenue ($ Millions)			
Interruptible	$3.01	**$23.69**	$114.48
Firm	2.45	**6.03**	8.17
Total	5.46	**29.72**	122.65
Net Benefits to Province Excluding Environment ($ Millions)			
Interruptible	$3.01	**$28.45**	$157.61
Firm	2.45	**6.56**	9.97
Total	5.46	**35.01**	167.58
B. Burrard Thermal			
Generation Volume (GW.h)			
Interruptible Export	304	**1,140**	---
Firm Export	76	**127**	---
Domestic	4,540	**1,167**	500
Total	4,920	**2,434**	500
Net Export Revenue ($ Millions)			
Interruptible	$1.52	**$6.84**	NA
Firm	1.03	**1.84**	NA
Total	2.55	**8.68**	NA
C. Implicit Value of NO_x Curtailment			
NO_x "Export" Tonnes	152	**507**	NA
Burrard's Net Revenue/Tonne	$16,750	**$17,125**	NA
BC Hydro's Net Revenue/Tonne	35,921	**58,660**	NA
Province's Net Benefits/Tonne	35,921	**69,092**	NA

Table 7.8 Cont.
Principal Assumptions

	Streamflow Conditions Low	Average	High
Export Allocation			
Purchases	62.0%	**43.3%**	15.0%
Burrard	38.0%	**31.7%**	0.0%
Hydro	0.0%	**25.0%**	85.0%
Total	100.0%	**100.0%**	100.0%
Export Prices (Mills/KW.h)			
Interruptible	19.0	**19.0**	19.0
Firm	27.5	**27.5**	27.5
Incremental Costs – BC Hydro (Mills/KW.h)[1]			
Purchases	16.0	**16.0**	16.0
Burrard	14.0	**13.0**	11.5
Hydro	5.5	**5.5**	5.5
Incremental Costs – Province (Mills/KW.h)			
Purchases	16.0	**16.0**	16.0
Burrard	14.0	**13.0**	11.5
Hydro	0.214	**0.214**	0.214
Contribution Margins (Mills/KW.h)			
(a) BC Hydro			
Interruptible	3.760	**6.580**	11.925
Firm	12.260	**15.080**	20.425
Total	5.460	**7.430**	12.265
(b) Province			
Interruptible	3.760	**7.902**	16.418
Firm	12.260	**16.402**	24.918
Total	5.46	**8.7518**	16.758
(c) Burrard Thermal			
Interruptible	5.000	**6.000**	NA
Firm	13.500	**14.500**	NA
Total	6.700	**6.850**	NA
NO_X Emission Rate (tonnes/GW.h)	0.40	**0.40**	0.40

[1] *Includes Operation, Maintenance & Administration at 0.2 Mills/KW.h for Burrard and Hydro, and 7% losses for Purchases and Hydro.*

(b) Step Two Summer Constraint (1994)

Table 7.8 reports the Commission's estimate of the cost of the second step (1994) summer emission cap. This calculation assumes a maximum daily NO_X emission rate during the restricted months of 5.02 tonnes of NO_X, a cap that conforms to the earlier GVRD Stage 2 target of an *annual* NOx emission of 1,833 tonnes. In this calculation, Burrard's capability is reduced to 4660 GW.h per year. Applying assumptions similar to those of the first phase, firm export volume falls to 400 GW.h, some 40 percent of the amount in the base case of Table 7.6, and the 600 GW.h lost is marketed as interruptible energy. The result for the average water year is an annual net revenue flow of about 30 million, compared with the 35 million dollar figure of the base case in Table 7.6. Thus imposition of the step two summer NO_X emissions cap costs B.C. Hydro about 5 million dollars per year, and the net benefit to the Province again falls by about the same amount.[16] As would be expected, the emissions cap has a relatively greater effect in a year of low streamflow and a negligible effect in a year of high streamflow.

There are two possible sources of downward bias in the Commission's estimates of the cost of emission caps. First, the expected level of interruptible sales might have to be reduced, since the possibility of valley gas purchases and heavy simultaneous exports will be limited by the caps. Second, it may be that the export market cannot absorb all the additional sales of secondary energy that were assumed in the Commission's calculations. However, as previously noted, the reported results may be upwardly biased to the extent that B.C. Hydro has system flexibility to offset some of the reduction in May through September Burrard capability.[17] On balance, it seems most likely that the cost of the caps will not be as high as the Commission's estimates.

As previously noted, the reported result may be upwardly biased to the extent that B.C. Hydro has system flexibility to offset some of the reduction in May through September Burrard capability.

The imposition of the two-step summer NO_X emission caps proposed by the Commission for 1993 and 1994 would not be without significant cost. It is estimated that the caps would reduce net annual revenue by approximately \$3 million in 1993 and by approximately \$5 million in 1994.

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16 The analysis in Table 7.8 assumes that with a monthly summer generation limit of 382 GW.h under average water that, firstly, domestic generation requirements are unaffected and, secondly, Burrard's exports decline modestly (i.e.., by 5% of 66 GW.h relative to Table 7.6) to account for periods in which some export generation above the cap would have otherwise occurred. Burrard's foregone exports are assumed sourced from spot purchases (i.e. the export market demand is assumed unchanged.

17 One alternative is that B.C. Hydro could possibly arrange interim purchases of firm power from Alberta at a cost that permitted a greater margin on firm energy sales than on interruptible sales.

7.5.4 Net Benefits to the Province of Exports with Emission Cap at GVRD 1995 Target Level

Late in the hearing the Commission received notice of a new annual target for 1995 NO_X emissions from Burrard. The new target was set at 1100 tonnes of NO_X per year. In Section 7.5.3, the Commission examined the effect on net revenues of its recommended two-step capping of summer emissions from Burrard. This section examines the situation that would arise if this procedure were to be extended to meet the most recent GVRD target for 1995.

Table 7.9 displays the predicted results of a May through September cap on Burrard emissions that would limit the daily maximum rate to an amount corresponding to the new GVRD annual target rate. With current technology still in place (0.4 tonnes of NO_X per GW.h), this would restrict Burrard's summer monthly capability to about 230 GW.h, yielding a total maximum output for the summer period of 1146 GW.h, and, in turn, an annual capped capability of 3,896 GW.h (corresponding to an unrestricted capability of 5,270 GW.h). As shown in Table 7.9 this would preclude B.C. Hydro from entering into any contracts for firm exports. However, it seems reasonable to assume that the level of interruptible exports could be maintained unchanged from that shown in Table 7.6. In this situation it was assumed that the proportion of exports attributed to hydro remains as in Table 7.6, but that the Burrard share is reduced by 15 percent, with the balance being made up by purchases.

The impact of this emissions cap on B.C. Hydro net revenue would be severe, a 9.1 million dollar (or 26 percent) reduction in the base, or expected, case. It might be noted that in this base case, the restriction on Burrard (after accounting for the elimination of firm export sales) would result in a reduction of 375 GW.h in system capability, thereby creating a system firm energy deficit. This could impose further costs, as it would be necessary to advance completion of new generating sources or contract outside the Province for capacity.

Because an emissions cap corresponding to the most recent GVRD target does have rather drastic implications, the assumptions underlying this case are more difficult to evaluate. Nevertheless, the figures in Table 7.9 suggest what might be termed a "crossover point." It may initially be in B.C. Hydro's interest to maximize revenue by utilizing system flexibility and adjusting exports, specifically, reducing commitments to export firm electricity. As the emissions restriction becomes more severe, however, at some point the revenue maximizing strategy will be either to install new

Table 7.9

Social Benefit–Cost Analysis of Energy Exports
NO_X Emissions Cap to Achieve 1,100 Tonnes Target
(Annual Values)

	Streamflow Conditions Low	Average	High
A. BC Hydro and Province			
Energy Export Volume (GW.h)			
Interruptible	1,000	**4,000**	10,000
Firm	0	**0**	0
Total	1,000	**4,000**	10,000
BC Hydro Net Revenue ($ Millions)			
Interruptible	$3.68	**$25.90**	$119.25
Firm	0.00	**0.00**	0.00
Total	3.68	**25.90**	119.25
Net Benefits to Province Excluding Environment ($ Millions)			
Interruptible	$3.68	**$31.18**	$164.18
Firm	0.00	**0.00**	0.00
Total	3.68	**31.18**	164.18
B. Burrard Thermal			
Generation Volume (GW.h)			
Interruptible Export	340	**1,132**	---
Firm Export	0	**0**	---
Domestic	3,806	**1,168**	500
Total	4,146	**2,300**	500
Net Export Revenue ($ Millions)			
Interruptible	$1.70	**$6.79**	NA
Firm	0.00	**0.00**	NA
Total	1.70	**6.79**	NA
C. Implicit Value of NO_X Curtailment			
NO_X "Export" Tonnes	136	**453**	NA
Burrard's Net Revenue/Tonne	$12,500	**$15,000**	NA
BC Hydro's Net Revenue/Tonne	27,059	**57,191**	NA
Province's Net Benefits/Tonne	27,059	**68,865**	NA

Table 7.9 Cont.
Principal Assumptions

	Streamflow Conditions Low	Average	High
Export Allocation			
Purchases	66.0%	**46.7%**	15.0%
Burrard	34.0%	**28.3%**	0.0%
Hydro	0.0%	**25.0%**	85.0%
Total	100.0%	**100.0%**	100.0%
Export Prices (Mills/KW.h)			
Interruptible	19.0	**19.0**	19.0
Firm	27.5	**27.5**	27.5
Incremental Costs – BC Hydro (Mills/KW.h)[1]			
Purchases	16.0	**16.0**	16.0
Burrard	14.0	**13.0**	11.5
Hydro	5.5	**5.5**	5.5
Incremental Costs – Province (Mills/KW.h)			
Purchases	16.0	**16.0**	16.0
Burrard	14.0	**13.0**	11.5
Hydro	0.214	**0.214**	0.214
Contribution Margins (Mills/KW.h)			
(a) BC Hydro			
Interruptible	3.680	**6.474**	11.925
Firm	12.180	**14.974**	20.425
Total	3.680	**6.474**	11.925
(b) Province			
Interruptible	3.680	**7.796**	16.418
Firm	12.180	**16.296**	24.918
Total	3.68	**7.7955**	16.418
(c) Burrard Thermal			
Interruptible	5.000	**6.000**	NA
Firm	13.500	**14.500**	NA
Total	5.000	**6.000**	NA
NO_X Emission Rate (tonnes/GW.h)	0.40	**0.40**	0.40

[1] *Includes Operation, Maintenance & Administration at 0.2 Mills/KW.h for Burrard and Hydro, and 7% losses for Purchases and Hydro.*

abatement technology or to change the role of Burrard. For example, the investment figures reported in Table 6.1 indicate that for an annualized cost on the order of 4.5 million dollars (based on their investment figure[18]), B.C. Hydro could install MACT technology that would reduce emissions to the GVRD 1995 target. This compares with the estimate in Table 7.9 of 9 million dollars as the annual cost of staying with current technology and suffering the emission cap restriction.

7.5.5 Net Benefits to the Province of Exports with Mandated Technology Abatement at Burrard

Looking further ahead, it is highly likely, if not certain, that with the completion of the Burrard Utilization Study and subsequent consultation among the concerned parties changes will take place at Burrard. Testimony presented by intervenors, notably the GVRD, pointed to the likelihood that the installation of SCR technology would be mandated.[19] We take this as a base case, bearing in mind that procedures are available for negotiations between B.C. Hydro and the GVRD that might lead to a preferred result - one in which at least one party was better off. As with the estimation of the possible effect of Commission-imposed operating restrictions, it is difficult to estimate how the net benefits attributed to exports might be affected in the event that SCR is mandated. Nevertheless, a rough estimate serves to indicate the likely implications for energy trade.

The Commission's calculations assume that the SCR technology will be required whether exports are being allowed or not. In this case, with a complete retrofit mandated for domestic purposes, exports should only bear short-run incremental cost. Any contribution to revenue net of operating cost that exports can make will ease the burden of abatement costs for the system. Thus, as shown in Table 7.10, the base case forecast of the net financial benefits associated with exports is identical to that given in Table 7.6

The one significant difference between the information presented in Table 7.10 and Table 7.6 is the implicit cost assigned to NO_X emissions. The figures suggest that to justify prohibiting Burrard's contribution to exports, NO_X emissions would have to be valued at over 60 thousand dollars per tonne in the base case.

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18 The annual (real) cost of capital retrofit over Burrard's remaining life can be estimated by applying a Capital Recovery Factor of about 10 percent; this method assumes an 8 % real annual discount rate (see Exhibit 106).

19 See Chapter 6.0 for a discussion of the term BACT and its relation to SCR.

Table 7.10

Social Benefit–Cost Analysis of Energy Exports
NO_x Technology Abatement to Achieve 660 Tonnes Target
(Annual Values)

	Streamflow Conditions Low	Average	High
A. BC Hydro and Province			
Energy Export Volume (GW.h)			
Interruptible	500	**3,000**	9,000
Firm	500	**1,000**	1,000
Total	1,000	**4,000**	10,000
BC Hydro Net Revenue ($ Millions)			
Interruptible	$1.90	**$19.88**	$107.33
Firm	6.15	**15.13**	20.43
Total	8.05	**35.00**	127.75
Net Benefits to Province Excluding Environment ($ Millions)			
Interruptible	$1.90	**$23.84**	$147.76
Firm	6.15	**16.45**	24.92
Total	8.05	**40.29**	172.68
B. Burrard Thermal			
Generation Volume (GW.h)			
Interruptible Export	200	**1,000**	---
Firm Export	200	**333**	---
Domestic	5,100	**1,167**	500
Total	5,500	**2,500**	500
Net Export Revenue ($ Millions)			
Interruptible	$1.00	**$6.00**	NA
Firm	2.70	**4.83**	NA
Total	3.70	**10.83**	NA
C. Implicit Value of NO_x Curtailment			
NO_x "Export" Tonnes	53	**178**	NA
Burrard's Net Revenue/Tonne	$69,375	**$60,938**	NA
BC Hydro's Net Revenue/Tonne	150,937	**196,875**	NA
Province's Net Benefits/Tonne	150,937	**226,609**	NA

Table 7.10 Cont.
Principal Assumptions

	Streamflow Conditions Low	Average	High
Export Allocation			
Purchases	60.0%	**41.7%**	15.0%
Burrard	40.0%	**33.3%**	0.0%
Hydro	0.0%	**25.0%**	85.0%
Total	100.0%	**100.0%**	100.0%
Export Prices (Mills/KW.h)			
Interruptible	19.0	**19.0**	19.0
Firm	27.5	**27.5**	27.5
Incremental Costs – BC Hydro (Mills/KW.h)[1]			
Purchases	16.0	**16.0**	16.0
Burrard	14.0	**13.0**	11.5
Hydro	5.5	**5.5**	5.5
Incremental Costs – Province (Mills/KW.h)			
Purchases	16.0	**16.0**	16.0
Burrard	14.0	**13.0**	11.5
Hydro	0.214	**0.214**	0.214
Contribution Margins (Mills/KW.h)			
(a) BC Hydro			
Interruptible	3.800	**6.625**	11.925
Firm	12.300	**15.125**	20.425
Total	8.050	**8.750**	12.775
(b) Province			
Interruptible	3.800	**7.947**	16.418
Firm	12.300	**16.447**	24.918
Total	8.05	**10.072**	17.268
(c) Burrard Thermal			
Interruptible	5.000	**6.000**	NA
Firm	13.500	**14.500**	NA
Total	9.250	**8.125**	NA
NO_X Emission Rate (tonnes/GW.h)	0.13	**0.13**	0.13

[1] *Includes Operation, Maintenance & Administration at 0.2 Mills/KW.h for Burrard and Hydro, and 7% losses for Purchases and Hydro.*

7.5.6 Other Net Benefits of Energy Trade

Sections 7.5.1 through 7.5.4 dealt with net benefits that might be expected from energy exports. For the most part, the concerns expressed by intervenors were premised on the connection between exports and the operation of either Burrard or the hydroelectric system. An underlying supposition would appear to be that the Commission might opt to recommend restrictions on, or prohibitions of, firm energy exports and *net* interruptible exports, so that the other benefits reviewed in Section 7.3. would not be jeopardized. It is for this reason that these other benefits do not appear in Table 7.6 and the other tables describing social net benefits.

As reviewed in Section 7.2, the Applicants cited benefits of electricity trade other than those attributable to exports. The combined annual benefit of three of these - non-treaty storage, other storage and equichange, and Alberta coordination - was estimated at 26.5 million dollars. Other benefits cited by the Applicants did not lend themselves to dollar valuation.

To obtain a complete valuation of net benefits of electricity trade, taking into account exports *and* the other benefits for which estimates were available, these latter benefits - valued at on the order of 25 million dollars per year - must be taken into account. Referring to the base case figures of Table 7.6, *total* anticipated net revenue benefits to B.C. Hydro are increased to about 60 million dollars per year. The corresponding figure with the Step II emissions cap is about 55 million dollars per year. Anticipated net benefits to the Province are increased by the same amount.

7.6 Commission Conclusions

In this chapter the Commission has attempted to systematically survey the potential gains and losses that Applicants and Intervenors have related to trade in electricity.

The Applicants estimate that significant net revenue will be generated from the sale of interruptible and firm energy. They cite other gains as well, in particular, substantial financial benefits from the ability to coordinate supply and demand of energy over a grid that includes Alberta, the PNW of the U.S. and California. Estimates of the magnitude of net revenue gains cannot be precise because the integrated nature of the B.C. Hydro system makes it impossible to identify the generating source of a particular quantity of energy that is exported. Furthermore, because of the storage capability of a predominately hydro system, this difficulty extends to the time dimension: operation of Burrard may permit storage of water that can then be used for generation at a later date. With the information available to it the Commission has provided its estimate of net revenue. This estimate does not differ significantly from that of B.C. Hydro; in a base (expected) case the net revenue to

B.C. Hydro from exports is likely to be 35 million dollars a year, which increases to 60 million dollars a year when other benefits that can be quantified are taken into account.

The Commission recognizes the necessity of expanding the scope of the analysis to include gains and losses that may be experienced by other parties or the Province as a whole. Some of these lend themselves to measurement, for example, the water rentals that appear as costs to B.C. Hydro are income that flows directly to the Province. Other gains and losses do not lend themselves to quantification. An example would be the increase in system reliability that coordination with other electricity utilities makes possible.

With regard to these other gains and losses, the main focus of the hearings was on environmental effects that might be associated with the generation of electricity for export. It is in the nature of these effects that techniques for measurement are not well developed. Measures are being developed that, while incapable of absolutely valuing quality of life or human health, will at least provide practical guidance in economic decisions. Such measures are already having an impact on the choice of type and the siting of new generating capacity. It is to be hoped that a coordinated effort by electrical utilities will lead to their incorporation into the decision framework of dispatching systems on the integrated grid.

In the present circumstances, the Commission closely examined the potential for measurement of what emerged from the hearings as the major environmental concern, NO_X emissions from the Burrard. Different techniques of measurement were proposed by intervenors, and a wide range of damage estimates cited. If high-end estimates were accepted, situations could arise where the operation of Burrard to supply export (or any other) electricity would be unacceptable. To deal with this possible combination of circumstances, the Commission has recommended certain near-term restrictions until the appropriate long-run strategies are implemented. The Commission's analysis indicates the likelihood that these costs will not be negligible. Compared with the base case, second-step curtailments of Burrard operation (proposed for 1994) could result in a loss of net revenue to B.C. Hydro of about 5 million dollars per year.

With regard to NO_X emissions, the Commission's analysis indicates that valuations of NO_X emissions beyond the range of those presented even for the SCAQMD (Southern California) would be required to offset the positive net benefits to the Province of electricity exports. Carbon emissions raise concern about global greenhouse effects, so that remedial action requires cooperation among utilities. The Commission saw possible positive and negative consequences of energy trade and lacked means to provide any measure of possible carbon related effects. Similarly, with regard to possible environmental effects of hydro system operation, both physical models and economic valuation techniques have not at this time been applied in B.C. The Commission was therefore unable to determine the balance of the positive and negative effects of hydro system operation as related to energy trade.

Returning to the Terms of Reference, the Commission assesses "the net benefits to the Province and the Applicants of the proposed removals" to be positive. This conclusion embodies the restrictions that the Commission has recommended, and it relies on the good faith of B.C. Hydro, the GVRD, and other parties to continue to address environmental quality problems.

Annual net benefits to B.C. Hydro, under average water conditions, are expected to total approximately $60 million from all sources. Approximately $35 million of this is expected to be derived annually from exports of electricity. In addition, some $5 million is expected to accrue to the Province in annual water fees.

8.0 SUMMARY OF PRINCIPAL CONCLUSIONS AND RECOMMENDATIONS

The following summary responds directly to the Terms of Reference provided to the Commission to govern the scope of the B.C. Hydro/POWEREX Energy Removal Certificate ("ERC") public hearing. Other recommendations, of secondary importance, appear in the text where the issues are discussed; they appear in bold face for ease of identification. Recommendations appearing in this summary may be abridged from those appearing in the body of the report.

In its introduction (Chapter 1.0) the Commission notes the very large number of export and generation related issues currently under review by a range of public agencies and by the industry itself. The following recommendations attempt to provide short-term decision-making guidance within the framework of longer-term changes facing the electric generating industry.

8.1 Net Benefits

The Commission concludes that net benefits to both the Province and the Applicants from the export of electrical energy and related services are positive and significant. The magnitude of these benefits, through the projected term of the ERC, under a number of different scenarios, is estimated in Chapter 7.0 and is summarized in Section 8.13 below.

8.2 Recommended ERC Term

The Commission concludes that the length of an ERC need not necessarily relate to the term of export contracts signed within the conditions of the ERC. The length of an ERC is related more properly to the need for periodic review of policies related to short-term exports.

> **The Commission recommends that the ERC requested by the Applicants, extending to September 30, 1997, be granted. It is recommended that the Certificate itself be qualified with respect to specific issues, as outlined in the following paragraphs and in the body of this report.**

8.3 Electricity Export Limits

B.C. Hydro/POWEREX have applied for electricity exports up to annual upper limits of:

Firm Power:	2,300 MW to the USA 1,200 MW to Alberta

Firm Energy:	6,000 GW.h
Interruptible Energy:	25,000 GW.h less concurrent firm exports

The power (capacity) limit is defined by the capability of provincial boundary interties. Energy limits represent the upper bound of availability under the most favourable river run-off and market conditions. The Commission believes it is important to retain maximum flexibility for B.C. Hydro/POWEREX to respond to high water and market conditions as they occur. Constraints on exports relate much more closely to low water conditions; critical low water governs many of the Applicants' export decisions.

The Commission recommends that the annual upper limits to electricity exports be retained at the levels proposed by the Applicants.

8.4 Reliability and Security

The reliability and security of domestic electricity supplies are significantly enhanced by the interconnection of British Columbian generating sources with U.S. and Alberta systems through coordination and emergency support agreements and Alberta reserve sharing.

The Commission sees the greatest threat to reliability and security of electrical energy supply to B.C. customers coming from possible over-commitment of resources to export through the signing of firm contracts covering a term beyond the range of confident prediction of supply sources and water conditions. The Commission proposes to limit this danger by limiting the maximum term of firm energy contracts to three years and by requiring specific Ministry approval of those over one year's duration (Sections 8.6 and 8.8.1, below).

The Commission does not believe export contracts for interruptible energy pose a threat to the reliability and security of domestic supplies of electricity and proposes fewer constraints on them.

8.5 Determining Removable Firm Surplus

The procedure currently in place for the determination of removable firm surplus takes the firm energy which can be supplied to the B.C. Hydro system in any year under the lowest historic four-year streamflow conditions (1942-46) and subtracts forecast domestic load requirements for each year of the requested Licence. Interruptible surplus is energy surplus to domestic demand primarily due to water flows above critical low water conditions, and can occur at any time.

The Commission recommends that, in future, in making the short-term firm energy surplus calculation any supply resource that is not yet committed (i.e. avoidable) not be included in the calculation. It is recommended that this same procedure be used to determine the short-term time-frame to which the maximum duration of firm export contracts under the ERC should be limited.

8.6 Determining "Short-Term" Time-Frame

B.C. Hydro's own estimation of the removable energy surplus under critical water, during the five-year term of the ERC, shows heavy reliance on non-hydro resources, some not yet committed. The Commission believes that only those resources already in place or already committed to serve domestic load should properly be considered when determining "removable energy surplus". When this definition is applied to the B.C. Hydro system, firm surplus becomes a net deficit by 1995/96.

The Commission recommends that the Applicants' short-term time-frame be defined as no more than a maximum of three years. Firm energy sales contracts longer than three years in duration should be referred to as long-term contracts because they will generally require additional investment commitments. The Commission recommends that export contracts for firm energy in excess of three years should not be permitted under this ERC.

8.7 Marketing Surplus Electricity in the One Year Time-Frame

Energy surpluses, both firm and interruptible, can be reliably determined, with low risk, during the short one-year time-horizon. An export market exists for such surplus and the Applicants believe this market can be enhanced by the institution of a Power Exchange Operation ("PEO"). The Commission concurs in the belief that the PEO concept has merit, and that it could lead to a more active short-term trade (less than one year) with improved financial returns to the Applicants and the Province.

The Commission recommends, subject to specific constraints set out in Chapter 4.0, that the Minister give favourable consideration to the establishment of the PEO which is currently the subject of a separate Application to the Ministry of Energy.

Furthermore, the Commission recommends that export contracts of less than one year's duration, whether conducted through the PEO or otherwise, not be subject to Ministerial approval.

8.8 Marketing Surplus Electricity in the One to Three Year Term

8.8.1 Firm Energy Sales

The Commission believes that sales of surplus firm energy carry a greater risk to the security of domestic supply as the term extends out towards the proposed three-year limit. Nevertheless, firm energy sales are attractive from a revenue point of view and the Commission believes such contracts can safely continue to be negotiated under appropriate conditions, subject to Ministry review.

The Commission recommends that all firm energy contracts in the one to three year term be made subject to approval by the Ministry of Energy and that the request for approval be required to demonstrate that the sale will not jeopardize domestic supply; will meet a minimum price test; will provide domestic interconnected utilities with at least fair market access and will not involve unacceptable environmental impacts.

8.8.2 Interruptible Energy Sales

The Commission sees no reason to limit interruptible sales contracts to a three-year term although contracts longer than three years are considered unlikely.

The Commission recommends that interruptible sales over one year and up to five years be permitted subject to minimum price tests, fair market access to domestic utilities, and subject in all cases to Ministry approval.

8.9 Priority For Domestic Utilities

The Commission believes that the current offer mechanism or "right of interception" for inter-connected domestic utilities is inappropriate if the PEO is to be instituted for electricity trade of less than one year's duration.

The Commission recommends, for trade of less than one year's duration, particularly if executed through the proposed PEO, that a fair market access policy replace the right of interception for domestic utilities. The Commission believes fair market access can be assured by specific changes to PEO operational procedures, details of which are given in Chapter 4.0.

The Commission believes that, with improved information flow to interconnected domestic utilities, fair market access conditions could be created for blocks of energy trading in the one to three year term (firm) or one to five year term (interruptible).

The Commission recommends that for trade of this nature the Applicants no longer be required to make specific offers to interconnected domestic utilities. Domestic utilities should, however, be provided with price and quantity information and with priority access to all blocks of energy offered for export, upon their expression of serious interest.

Alternatively, a "right of interception" could be considered for contracts over one year by incorporation of clauses similar to Clauses 8 and 12 of the existing ERC.

8.10 Operating Procedures and the Environmental Aspects of Energy Removals

8.10.1 Generation from Hydraulic Systems

Incremental effects of export trade on B.C. Hydro reservoirs and connecting river systems are generally small and are normally over-shadowed by total system operation impacts for domestic needs. In making dispatch decisions, B.C. Hydro generally attempts to consider environmental impacts in a qualitative way and to adjust its dispatch accordingly. However, B.C. Hydro makes no attempt to formally evaluate the cost of these multiple impacts in its system operations models.

U.S. utilities operating on the lower Columbia (below the Canadian border) are currently carrying out a System Operation Review with the objective of modelling system operations so as to formally evaluate environmental costs associated with dispatch decisions.

It is recommended (Chapter 5.0) that B.C. Hydro be required to move in the same direction as the U.S. utilities so as to more fully account for the environmental impact of dispatch decisions.

8.10.2 Generation from Alberta Sources

Alberta generation can provide the source for some of British Columbia's export trade. Alberta energy purchases by the Applicants are normally supplied from coal-fired resources. To the extent that this generation may be substituted for gas-fired thermal generation in the importing region, there could be a net contribution of carbon dioxide, sulphur dioxide, and particulates to the North American environment.

In contrast, when water-based exports are occurring there is an environmental benefit as such exports usually displace U.S. thermal generation.

8.10.3 Costing Incremental Environmental Effects Related to Export Generation

Currently, B.C. Hydro does not attempt to specifically cost environmental effects related to generation from any of its sources. No other member utility in the Western Systems Power Pool yet applies environmental costing to dispatch of its various generating sources.

The Commission recommends that B.C. Hydro move towards the identification and incorporation of environmental costs in its dispatch decisions. Until such time as this is universally achieved, the Commission recommends that a minimum margin of 0.3 cents per kW.h be incorporated into POWEREX's export supply price to cover unidentified environmental effects of incremental export generation within B.C.

8.10.4 Export Contract Review

The Commission suggests that a more complete review of environmental impacts of electricity exports would result from more formal participation by the Ministry of Environment.

The Commission recommends that consideration be given to approval of electric energy export contracts by the Minister of Energy *in consultation with* the Minister of Environment.

8.11 The Role of the Burrard Thermal Generating Station

The 912.5 MW Burrard gas-fired thermal generation station is capable of contributing up to 5,520 GW.h per year to B.C. Hydro's integrated system. In years when water supplies to the hydroelectric system are well above average the station may not operate at all. When runoff is weak the station is likely to generate at a relatively high level. B.C. Hydro predicts an average level of operation of 2,500 GW.h per year during the period of the ERC.

It is impossible to predict how much of this generation will be in support of exports; however, Burrard is likely to be used to "firm up" export contracts if and when such contracts are negotiated. Burrard contributes to system loads outside the winter season by generating from low-cost valley gas to supplement hydroelectric generation and a significant part of this summer generation may contribute to exports.

8.12 Environmental Impacts of Burrard

The primary environmental impact from Burrard is on the Lower Fraser Valley ("LFV") airshed. Nitrous oxides emitted from the plant react with volatile organic compounds in the presence of sunlight to create ground level ozone. At higher concentrations ozone can be damaging to the respiratory tract of humans and can affect crop yields.

The Burrard plant is the next largest point source of NO_X, after the cement plants, in the LFV airshed. When operating at full load, it contributes between two and four percent of the total airshed emissions of NO_X. Ozone concentrations are not linearly related to NO_X emissions. They vary with meteorological conditions; episodes of high concentrations occur most frequently in the summer months due to elevated temperatures, longer hours of sunlight, temperature inversions which limit the mixing depth, and light winds. Daily on-shore summer breezes concentrate the ozone in the central Fraser Valley where the effect is most marked.

8.12.1 Permitted Emission Limits

Pollutant emissions from Burrard are governed by a permit issued by the District Director, Air Quality and Source Control, of the GVRD. Heretofore, NO_X emissions have been limited to 170 mg/m^3 from each stack source, at three percent oxygen. Burrard's emission permit expired on April 30, 1992 (during the hearing) and was renewed at the current levels, but B.C. Hydro was placed on notice that they would be required to install NO_X reduction equipment to reduce these emissions to 55 mg/m^3 as soon as possible after completion of B.C. Hydro's ongoing "Burrard Utilization Study". Evidence at the hearing indicated a cost of $45 to $100 million to install MACT or SCR technology (see Chapter 6.0) on all units, which would achieve the lower level required.

The air emissions permit for Burrard has an over-riding ozone episode control clause requiring the plant to shut down its operation when a high ozone episode is seen to be building.

8.12.2 The GVRD Air Quality Management Plan ("AQMP")

Stage 2 of the GVRD AQMP was published during the ERC hearing and filed in evidence. The plan has a target of a 50 percent reduction in thermal generating station point source emissions, below current levels by the year 1995. Different sources are assigned differing rates of reduction related to the industry's state of emissions reduction technology.

The Stage 2 AQMP for Burrard translates to a plant limit of 1,100 tonnes per year of NO_X by 1995 and 660 tonnes per year by the year 2005. These figures compare with a current annual emission rate of 2,200 tonnes with the plant operating at maximum annual capability of 5,520 GW.h per year. This energy output capability is not distributed evenly throughout the year. For technical reasons, related to maintenance and to the availability of lower-cost summer gas, the energy rate is highest during the summer months.

The Commission is of the view that limiting Burrard emissions by means of an annual, monthly or daily plant "cap" is preferable to the GVRD's current method of limiting emissions from each individual stack. The ultimate objective is to limit the tonnage emitted: how the reduction is achieved should be left to the industry itself. Determination of the most cost-effective way to reduce emissions at Burrard is the primary purpose of the Burrard Utilization Study now underway. Limiting emissions from each stack and tying the emission level to specific technology minimizes any opportunity for the utility to exercise ingenuity in finding the most cost-effective solution.

The Commission urges the Ministry of Energy and the Ministry of Environment to work with the GVRD District Director in considering the NO_X "cap" concept for Burrard in setting emission limits in the future.

8.12.3 Reducing Burrard's Contribution to Critical Summer Ozone Formation

After listening to the evidence on summer ozone impacts in the Lower Fraser Valley, the Commission is satisfied that a serious problem exists. While Burrard contributes less than four percent of the airshed's NO_X on an annual (average) basis, the fact remains that it is the second largest point source in the valley and that its production from lower-cost valley gas may tend to be high in the summer months when the ozone problem is at its worst. While the precise plant contribution to exports is impossible to determine, Burrard does unquestionably contribute to the firming of summer export contracts.

The Commission concludes that Burrard may be used in support of exports, subject to reduction in NO_X emissions during the period May 1st to September 30th, and recommends that these constraints be made a condition of the requested ERC.

As an interim measure, until the Burrard Utilization Study is complete and a clear program for NO_X control is in place, the Commission proposes a two -step cap on the tonnage of NO_X emissions during the period May 1st to September 30th.

The Commission recommends that B.C. Hydro be required to cap its NO_X emissions from May 1st to September 30th at the following levels:

Summer 1993 - Daily Cap: 6.03 tonnes NO_X
(This corresponds to an annual rate of 2,200 tonnes, evenly distributed on a daily basis)

Summer 1994 - Daily Cap: 5.02 tonnes NO_X
(This corresponds to an annual rate of 1,833 tonnes, evenly distributed on a daily basis)

It should be noted that an annual cap at the proposed 1994 rate was offered to the GVRD by B.C. Hydro, for the 1992 calendar year only, but this proffered reduction was not pursued.

The financial implications of these caps and of the ultimate 1995 NO_X emission level required by the GVRD's Stage 2 Air Quality Management Plan are provided in Chapter 7.0 and in Section 8.13 below.

8.12.4 Air Emissions Modelling

An air emissions model for the Lower Fraser Valley, capable of precisely identifying Burrard's role in ozone formation, has not yet been applied. Sophisticated reactive plume models do exist, although the complex topography and meteorology of the Fraser Valley complicate their application to this area.

The Commission concludes that up-to-date information on the dispersion and the ultimate impact of the Burrard plume is not now available but is capable of being generated.

The Commission recommends that the Applicants be required to provide information on the separate effects of Burrard as an embedded source within a regional oxidant model. It is further recommended that, to achieve this objective, the Applicants collaborate with the GVRD, and federal and provincial government agencies in their ongoing modelling activities.

8.13 Quantifying Net Benefits

The Commission has attempted to evaluate the annual net financial benefits to the Applicants and to the Province from the proposed removals under four different scenarios:

(i) Under existing air emissions permits at Burrard (Base Case).

(ii) With application of the Commission's recommended 1993 cap on Burrard's summer emissions.

(iii) With application of the Commission's recommended 1994 cap on Burrard's summer emissions.

(iv) With emissions controlled to the 1995 GVRD Stage 2 Air Quality Management Plan level.

The above analyses, reported in Chapter 7.0, are based on B.C. Hydro's projections, modified as necessary. They examine a range of values covering low water, average water and high run-off conditions. The figures include no allowance for incremental environmental impacts (see Section 7.4.2).

(a) Base Case (Existing Emission Conditions)

The Commission estimates annual net revenue to the Applicants from firm and interruptible energy exports to be:

Net Revenue to Applicants	Low Water	Average Water (Millions of dollars)	High Water
Firm Energy	2	15	107
Interruptible Energy	6	20	21
Total	8	35	128

Water rentals accruing to the Province would add to the above net financial benefits, from zero (low water year) to $45 million (high water year).

Other benefits of electricity trade include coordination with Bonneville Power Administration and Alberta utilities, storage, equichange and other services. The Commission estimates quantifiable net benefits of this type at approximately $25 million per year.

(b) 1993 Capped Case

The net effect of imposing the proposed NO_X emissions cap on Burrard is to reduce the above-described net annual financial benefit by approximately $3 million in an average water year.

(c) 1994 Capped Case

The net effect of applying the recommended second stage cap in 1994 is to reduce the base case net financial benefits by about $5 million in an average water year.

(d) The 1995 Stage 2 GVRD Air Quality Management Plan NO_X Level

Because of the greater difficulty in selecting underlying assumptions, the figures for this case are less certain. However, they are believed to provide a reasonable estimate of the impact of the full emissions abatement required by the GVRD for 1995.

The result, if there is no change in abatement technology, would be to still further reduce the estimated net revenue from exports under average water conditions from the current level of approximately $35 million per year to the Applicants to some $26 million per year, resulting in an annual financial loss of about $9 million.

The range of options available to the Applicants to mitigate the above losses has not been fully explored, and hence it may be reasonable to expect actual losses to be somewhat less than the estimates cited above.

The Commission's analysis of emission caps and abatement technology indicates that the social cost of air emissions would have to be at the high end of current estimates of environmental externality in North America before exports that rely on Burrard would lead to negative net benefits for the Province. Further, illustrative calculations suggest that a cap on Burrard emissions may be a more cost effective means of achieving targetted emission reductions, as compared to mandating abatement by a technological retrofit to the plant. This is because, unlike most facilities, the plant's value to the B.C. Hydro system is not necessarily dependent upon its full-time operation.

GLOSSARY OF TERMS

Capacity (Power)

This is the rate at which electricity can be instantaneously produced by a generating plant, it is usually measured in kilowatts or megawatts.

Demand

The amount of electricity required by the system or by the customers. Also referred to as load.

Demand-Side Management (DSM)

The actions taken by a utility or government to influence the use of energy. May involve reducing demand by improving efficiency or shifting demand to another time of the day or year. B.C. Hydro's demand-side management program is called Power Smart.

Energy

Is the amount of electricity produced by a generating plant over a period of time, measured in kilowatt hours, megawatt hours or gigawatt hours.

Energy Storage

The temporary storage of energy, usually in the form of water in a reservoir for return at a later time.

Exchange

The transfer of electricity between utilities at different time periods to achieve a more economic or efficient overall system operation. Such transfers are possible because of differences in electricity demand, generation resource capability, or system operating characteristics. An equal exchange of energy is referred to as "equichange".

Firm Electricity Sale

The sale of electricity either on a long-term or short-term basis for which availability of supply is assured.

Firm Energy

Energy available from the B.C. Hydro system under critical water conditions. This latter defined as the lowest recorded four year water sequence-1942 to 1946.

Gigawatt Hour (GW.h)

A unit of electrical energy. One gigawatt hour is equivalent to 1,000,000,000 watt hours.

Independent Power Producer (IPP)

The owner of a privately owned power generating facility which may be connected to the B.C. Hydro system to supply electricity for domestic or export markets.

Interruptible Electricity Sales

The sale of electricity of which the availability of supply is not assured and therefore may be cut off at any time.

Kilowatt Hour (kW.h)

A unit of electrical energy. One kilowatt hour is equivalent to 1,000 watt hours.

Life Cycle Cost

The unit cost of output from an investment that includes both operating cost and annualized capital costs.

Load Factoring

The process of managing the peak load demands of an electrical system which may involve exchanging peak hour capacity with another interconnected system.

Long-Term Trade

Electricity trade involving the construction or advancement of new projects solely for the purpose of export.

Losses

Energy losses in electric power systems which result from the transmission and distribution of electricity.

Marginal Cost

The difference in total cost between the production of x units and the production of x + 1 units. Marginal cost is used to denote the change in cost which results from a small change in output.

GLOSSARY OF TERMS

Mill

One mill equals one-tenth of a cent. The "mill" is frequently used as a monetary measure when referring to the cost of producing electricity.

Petajoule (PJ)

Is one million gigajoules. One gigajoule being 0.95 thousand cubic feet of natural gas at 1,000 BTU per cubic feet, or 0.28 megawatt hours of electricity.

Reliability

A measure of the continuity of electric service over a long period of time.

Resource Smart

A B.C. Hydro program intended to capture all cost-effective actions that would increase the energy output from existing B.C. Hydro facilities.

Secondary Energy

Energy from the B.C. Hydro system that exceeds the amount produced at critical water levels (see firm energy).

Self-Generation

Generation of electricity by a customer for its own use.

Short-Term Trade

Electricity trade that involves only surplus electricity from existing and committed generating and transmission facilities.

Valley Gas

Base load gas purchased by a gas utility and not needed for the firm requirements of its customers. Normally available for sale to customers, such as electric utilities, only during off-peak sales periods.

Province of British Columbia

OFFICE OF THE MINISTER

Ministry of Energy, Mines and Petroleum Resources

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BRITISH COLUMBIA UTILITIES COMMISSION
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November 19, 1991

Mr. John G. McIntyre
Chairman and Chief
Executive Officer
B.C. Utilities Commission
6th Floor, 900 Howe Street
Vancouver, British Columbia
V6Z 2N3

Dear Mr. McIntyre:

Attached is an Order referring the B.C. Hydro/POWEREX Energy Removal Certificate Application to the B.C. Utilities Commission for a review and public hearing pursuant to sections 24(1)(a) and 25 of the Utilities Commission Act.

Although a temporary Commissioner has not been named in the Order, the Ministry would like to involve the Commission in the selection of a suitable individual, with special expertise in environmental issues, to assist with the review of the Application. I have asked Mr. Philip D. Carter, Director of the Ministry's Electricity Policy Branch to contact you on this matter.

Finally, I request that the Commission consult with the Ministry of Environment, Lands and Parks, and the Greater Vancouver Regional District, on the design of any additional studies that may be needed to help assess the environmental impacts of the operation of the Burrard Thermal Generating Station.

Yours sincerely,

Anne Edwards

Anne Edwards
Minister

Attachment

cc: Honourable Moe Sihota
Minister of Labour and
Consumer Services and
Minister Responsible for
Constitutional Affairs

Mr. Philip D. Carter

TERMS OF REFERENCE

**IN THE MATTER OF
THE UTILITIES COMMISSION ACT ("the Act")
S.B.C. 1980, c. 60**

and

**IN THE MATTER OF AN APPLICATION BY THE
BRITISH COLUMBIA HYDRO AND POWER AUTHORITY ("B.C. Hydro")
AND THE
BRITISH COLUMBIA POWER EXCHANGE CORPORATION ("POWEREX")
FOR AN ENERGY REMOVAL CERTIFICATE ("ERC") FOR ELECTRICITY EXPORTS
TO THE UNITED STATES AND ALBERTA**

**DISPOSITION OF APPLICATION AND TERMS
OF REFERENCE FOR REVIEW BY THE
BRITISH COLUMBIA UTILITIES COMMISSION**

WHEREAS, B.C. Hydro and POWEREX ("the Applicants") currently jointly hold two separate ERCs for the removal of electricity to the United States and Alberta, respectively; and,

WHEREAS, the Applicants must apply to the Minister of Energy, Mines and Petroleum Resources ("the Minister"), pursuant to Condition 9 of ERC-80(8403), as amended, for approval to export firm power or energy; and,

WHEREAS, the Minister by Orders ERC-80(8403)A6 and ERC-32(8710)A3 dated September 10, 1991, extended the terms of the existing ERCs from September 30, 1991, for a period of six months, until March 31, 1992; and,

WHEREAS, pursuant to section 23 of the Act, and in conformance with the requirements of B.C. Regulation 426/90, the Applicants applied jointly for an ERC covering electricity removals to the United States and Alberta by way of an Energy Removal Certificate Application ("the Application") submitted April 29, 1991; and,

WHEREAS, the Application is for a period of six years until September 30, 1997, ("the Term") and covers the following removals:

1. short-term firm power of up to 2,300 megawatts ("MW") to the United States and up to 1,200 MW to Alberta; and,

2. short-term firm energy in amounts up to 6,000 gigawatt hours ("GW.h") in each year of the Term; and,

3. interruptible energy in amounts up to 25,000 GW.h in each year of the Term less any short-term firm energy removals.

NOW THEREFORE, pursuant to sections 24(1)(a) and 25 of the Act, the Minister hereby refers the Application to the British Columbia Utilities Commission ("the Commission") for review. The Commission shall hear the Application in a public hearing, in accordance with the following Terms of Reference, and invite comments from interested parties.

TERMS OF REFERENCE

OBJECTIVE

The Commission shall hear the Application in a public hearing in accordance with the criteria outlined below and, on conclusion of the hearing, shall submit a report to the Lieutenant Governor in Council by February 28, 1992, with recommendations on whether an ERC should be issued or refused and, if issued, the conditions, if any, to which the ERC should be made subject.

EVALUATION CRITERIA

1. **The Commission shall review the Application and make an assessment of the net benefits to the Province and the Applicants of the proposed removals.**

2. **The Commission shall review the Application to ensure that reliability and security of electricity supply to British Columbians will not be adversely affected by the proposed removals. Without limiting the generality of the foregoing, the Commission shall also review any written agreements submitted to the Minister by the Applicants or either of them, pursuant to Condition 9 of ERC 80(8403) as amended, prior to the conclusion of this review.**

3. The Commission shall review and assess the current provincial procedures for determining B.C. Hydro's removable short-term energy surplus, as outlined in the "Reasons for Decision" for ERC-80(8403) and "ERC-80(8403)", as amended, which are attached hereto and form part hereof, in view of the changes which have occurred and are expected in the resource mix available to B.C. Hydro, including demand reduction programs and purchases from other electricity producers.

4. The Commission shall review the issue of the time frame which should be considered "short-term" for the purpose of the Application.

5. The Commission shall review the present offer mechanism, whereby electricity proposed for short-term removal by the Applicants is first offered to domestic interconnected utilities on terms and conditions no less favourable than the proposed removals, and determine whether this mechanism is the best method available for the purposes of demonstrating a removable energy surplus and providing evidence of a fair market price.

6. The Commission shall review the Application to assess the environmental impacts from the proposed removals and whether the Applicants' operating practices are adequate to mitigate any unacceptable impacts and, in particular, the Commission shall:

   (a) conduct a review of the role of the Burrard Thermal Generating Station (Burrard) in serving the export market; and,

   (b) assess the impact on the Lower Mainland airshed, under various meteorological conditions, of the air emissions which can be directly attributable to increased generation from Burrard to serve the export market; and,

   (c) consult with the Ministry of Environment, Lands and Parks and the Greater Vancouver Regional District to ensure that any studies/modelling which may be necessary for assessing the environmental impact of the operation of Burrard are adequate to reach reliable recommendations.

Anne Edwards

Anne Edwards
Minister

Dated this 21st day of November, 1991.

BRITISH COLUMBIA UTILITIES COMMISSION

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-1-92

IN THE MATTER OF the Utilities Commission Act, S.B.C. 1980, c. 60, as amended

and

IN THE MATTER OF an Application by
British Columbia Hydro and Power Authority
and the
British Columbia Power Exchange Corporation

BEFORE:	J.G. McIntyre, Chairman;	)	
	J.D.V. Newlands, Deputy Chairman;	)	
	N. Martin, Commissioner; and	)	January 6, 1992
	F.C. Leighton, Commissioner	)	

O R D E R

WHEREAS:

A. Pursuant to Section 23 of the Utilities Commission Act ("the Act") and in conformance with the requirements of B.C. Regulation 426/90, on April 29, 1991 British Columbia Hydro and Power Authority ("B.C. Hydro") and British Columbia Power Exchange Corporation ("POWEREX") referred to as ("the Applicants") applied jointly to the Minister of Energy, Mines and Petroleum Resources ("the Minister") for an Energy Removal Certificate ("ERC") to allow for the export of power and energy to the United States and Alberta; and

B. The ERC Application ("the Application") is for a period of six years until September 30, 1997 ("the Term") and covers the following removals:

1. Short-term firm power of up to 2,300 megawatts ("MW") to the United States and up to 1,200 MW to Alberta; and

2. Short-term firm energy in amounts up to 6,000 gigawatt-hours ("GW.h") in each year of the Term; and

3. Interruptible energy in amounts up to 25,000 GW.h in each year of the Term less any short-term firm energy removals.

C. The Minister, by Orders ERC-80(8403)A6 and ERC-32(8710)A3, dated September 10, 1991, extended the terms of the existing ERC's from September 30, 1991 for a period of six months, until March 31, 1992; and

D. By letter dated November 19, 1991, pursuant to Sections 24(1)(a) and 25 of the Act, the Minister referred the Application to the Commission for review in a public hearing in accordance with specific Terms of Reference provided and attached as Appendix A to this Order; and

E. On December 3, 1991, and December 11, 1991, the Commission, pursuant to Clause 6(c) of the Terms of Reference, convened meetings with representatives from B.C. Hydro, the Ministry of Energy, Mines and Petroleum Resources, the Ministry of Environment, Lands and Parks, and the Greater Vancouver Regional District, to discuss the current information base and studies necessary to assess the environmental impact of the operation of B.C. Hydro's Burrard Thermal Generating Plant in support of the Application; and

.../2

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-1-92

F. On December 20, 1991, the Commission wrote to the Minister providing an update of the discussions held with the agencies identified in paragraph E above, and requested an extension of the deadline to March 30, 1992, for submission of the Commission's report on the hearing.

NOW THEREFORE the Commission orders the Applicants as follows:

1. A public hearing is to commence at 9:00 a.m. local time, Tuesday, February 11, 1992 in the Hearing Room of the British Columbia Utilities Commission, 6th Floor, 900 Howe Street, Vancouver, B.C.

2. B.C. Hydro will arrange for publication, by January 7, 1992, of a Notice of Public Hearing, as per attached copy, in one issue of each of the Vancouver Sun, The Province and such other appropriate local news publications as may properly provide adequate notice to those persons in the province who may have an interest in the Application.

3. Intervenors and Interested Parties intending to be present and participate in the public hearing should give written Notice of Intention to do so to the Commission Secretary and to the Applicant, to be received not later than Thursday, January 16, 1992. Such Notice should state the nature of the interest in the proceeding.

4. Intervenors and Interested Parties intending to file a written submission should provide one copy to the Commission Secretary and one copy to the Applicant to be received not later than Monday, January 27, 1992.

5. Intervenors and Interested Parties intending to make a request for additional information of the Applicant, should provide one copy of the request to the Commission Secretary and one copy to the Applicant to be submitted not later than Thursday, January 16, 1992.

   B.C. Hydro is required to respond to all information requests by Thursday, January 30, 1992.

6. B.C. Hydro is to file with the Commission not later than Wednesday, January 22, 1992, any prepared testimony and supplemental material upon which it intends to rely.

DATED at the City of Vancouver, in the Province of British Columbia, this 7th day of January 1992.

BY ORDER

John G. McIntyre
Chairman

/mmc
Attachments

BRITISH COLUMBIA UTILITIES COMMISSION

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-17-92

IN THE MATTER OF the Utilities Commission Act, S.B.C. 1980, c. 60, as amended

and

IN THE MATTER OF an Application by
British Columbia Hydro and Power Authority
and the
British Columbia Power Exchange Corporation
and
Commission Order No. G-1-92

BEFORE:	J.G. McIntyre, Chairman; J.D.V. Newlands, Deputy Chairman; N. Martin, Commissioner; and F.C. Leighton, Commissioner	February 4, 1992

O R D E R

WHEREAS:

A. On January 6, 1992 the Commission, by Order G-1-92, set down an Application ("the Application") for an Energy Removal Certificate from British Columbia Hydro and Power Authority ("B.C. Hydro") and British Columbia Power Exchange Corporation ("POWEREX") referred to as ("the Applicants") for a public hearing to commence February 11, 1992 in Vancouver, B.C.; and

B. The Minister, by Orders ERC-80(8403)A6 and ERC-32(8710)A3, dated September 10, 1991, extended the terms of the existing ERCs from September 30, 1991 for a period of six months, until March 31, 1992; and

C. On January 22, 1992 the Applicants applied to the Minister for an extension of the term of the ERC-80(8403), as amended, from March 31, 1992 to June 30, 1992; and

D. On January 22, 1992 the Applicants applied to the Commission for an adjournment of the public hearing as authorized by Commission Order No. G-1-92 to allow sufficient time to answer all information requests made by Registered Intervenors and the Commission staff; and

E. On February 4, 1992 the Minister agreed to change the November 19, 1991 Terms of Reference and advised that a Report from the Commission would be required on or before June 30, 1992; and

F. The Commission has considered all the information with respect to this matter and confirms that an adjournment to the proceedings is necessary and in the public interest.

NOW THEREFORE the Commission orders the Applicants as follows:

1. The public hearing into the Application as scheduled by Commission Order No. G-1-92 is cancelled and is re-scheduled to commence at 9:00 a.m. local time, Monday, April 6, 1992 in the Hearing Room of the British Columbia Utilities Commission, 6th Floor, 900 Howe Street, Vancouver, B.C.

2. B.C. Hydro will arrange for publication, Monday, February 10, 1992, a Notice of Public Hearing-Rescheduling, as per attached copy, in one issue of each of the Vancouver Sun, The Province and such other local community news publications in the Province so as to properly provide adequate notice to those persons who may have an interest in the Application.

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-17-92

3. Intervenors and Interested Parties intending to be present and participate in the public hearing should give written Notice of Intention to do so to the Commission Secretary and to the Applicant, to be received not later than Friday, February 21, 1992. Such notice should state the nature of the interest in the proceeding. Those parties already registered with the Commission are not required to re-register.

4. Intervenors and Interested Parties intending to file written submissions should provide one copy to the Commission Secretary and one copy to the Applicant to be received not later than Monday, March 23, 1992.

5. The Applicants are to respond to those Information Requests made prior to January 16, 1992 by Friday, March 6, 1992.

6. B.C. Hydro is to file with the Commission not later than Friday, February 21, 1992, any additional prepared testimony and supplemental material upon which it intends to rely.

7. Intervenors and Interested Parties intending to make a request for additional information of the Applicant, should provide one copy of the request to the Commission Secretary and one copy to the Applicant to be submitted not later than Monday, February 24, 1992.

   B.C. Hydro/POWEREX is required to respond to all such information requests by Friday, March 13, 1992.

DATED at the City of Vancouver, in the Province of British Columbia, this 5th day of February, 1992.

BY ORDER

John G. McIntyre
Chairman

/ssc
Attachments