1995 Integrated Electricity Plan

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EXECUTIVE SUMMARY

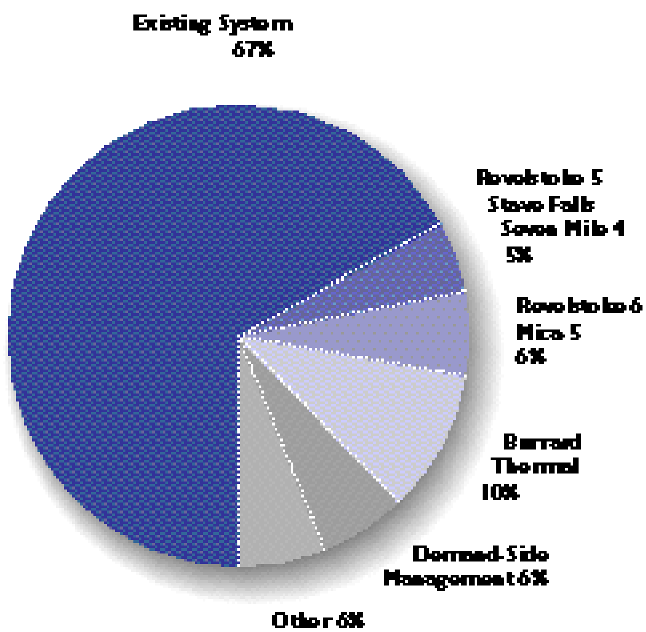
This *1995 Integrated Electricity Plan* (also known as the Integrated Resource Plan, or more simply, the Plan) provides BC Hydro's perspective on the options available to meet the future electricity needs of our customers. The Plan is the result of a comprehensive planning and consultation process which began in December 1994 and which included focused stakeholder advice on the development of the Plan. That advice was provided by a Consultative Committee comprised of representatives from residential and industrial customer groups and individuals representing environmental interests, regional planning, the natural resources dependent sector, independent power producers and BC Hydro. The commitment of the Consultative Committee members to the process and their advice on the development of the Plan are acknowledged and appreciated.

The options considered in the Plan include both generation and demand-side resources, as well as transmission lines and station facilities that increase the transmission capacity of the system. All options were evaluated according to a variety of attributes including financial, technical, environmental, social/community and economic development. The Plan places particular focus on those actions that have to be taken over the next few years, to either acquire resources or ensure their continued availability, together with actions to address future risks and uncertainties.

The Plan is cognizant of and has the flexibility to be able to respond to changing market conditions and future uncertainties. It was developed during a period of uncertainty and transition in the electric industry. In the past, uncertainties in electricity planning focused primarily on the level of future demand and the availability of various resources to meet that demand. Today rapid changes in technology, global economies, the environment and public interest are increasing the uncertainties associated with demand and resource availability. These changes are further compounded by uncertainty over the role of competition in electricity markets. BC Hydro must consider the availability of utility-owned resource options, private power options and the implications of open access on the transmission system. Demand for a wider variety of products and services means that electricity planning must become more customer focused.

The Plan was developed based on current information which will need to be tested to a greater extent and level of detail, taking into account the results of the current review of the electric utility industry in British Columbia, before specific commitments for major acquisitions or expansions are made.

There are two main deliverables embodied in the Plan, namely the 20-Year Outlook and the Four-Year Action Plan.



Year 2014 Probable Peak Demand:13,300 MW

Figure 1:

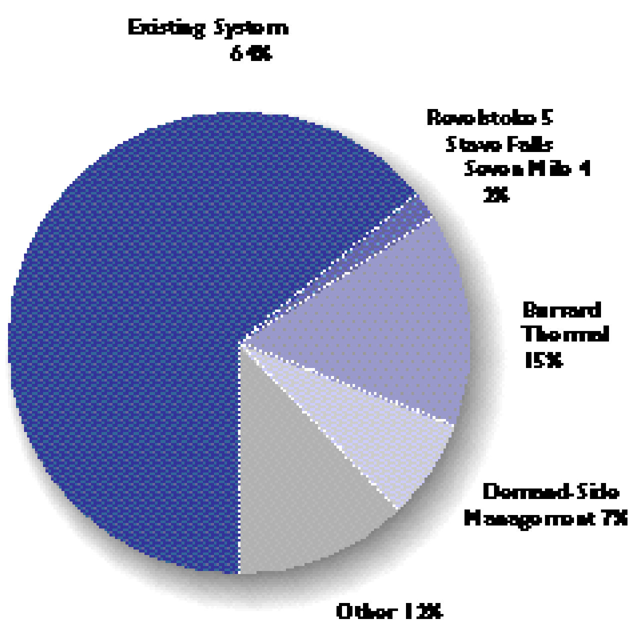
20-Year Capacity Outlook

(Note:Some projects provide capacity but little or no energy. This results in the differences in the percentages between the two figures.)

The 20-Year Outlook

The forecast of the annual demand for electricity over the next 20 years indicates a total increase of 4,100 MW of capacity (peak demand) and 25,000 GWh of energy. The 20-Year Outlook identifies the resource options that best meet that forecast of the demand for electricity as guided by corporate and planning objectives. Figures 1 and 2 show the makeup of the 20-Year Outlook for BC Hydro's system in terms of both capacity (peak demand) and energy (total annual requirements) in the year 2014.

Given the contribution that a repowering of the existing Burrard Thermal plant makes to the 20-Year Outlook, it is important to put some perspective on this option. Although the results of this strategic level Plan indicate that this option, which would comprise the installation of the latest technology in the form of combined cycle combustion turbines, could have cost, rate and environmental benefits, the studies undertaken in the development of this Plan are based on current knowledge of emerging technology. The potential cost advantages, higher efficiencies and air emission improvements, together with the issue of availability and price of natural gas, would require detailed investigation, evaluation and public consultation before specific commitments to repower the Burrard Thermal Plant could be made. Indeed, this was the general agreement of the Consultative Commitee who provided advice to BC Hydro on the development of this Plan.



Year 2014 Probable Demand:73,600 GWh

Figure 2:

20-Year Energy Outlook

(Note:Some projects provide capacity but little or no energy. This results in the differences in the percentages between the two figures.)

In the process of preparing this Plan, the 20-Year Outlook was tested against a variety of future conditions and uncertainties and strategies were developed to deal with them. This type of preparation is valuable in assisting the Corporation to respond or adapt to rapid change. The following future conditions and uncertainties were considered: variations in the demand for electricity and the price of natural gas; the availability of other resources; and the possibility of stricter environmental regulations.

The Four-Year Action Plan

Although it is important to look at where we think we will be 20 years from now in terms of demand, resources and markets in general, it is even more important to recognize that significant commitments based on the 20-Year Outlook cannot be made due to the changing nature of the industry. An action plan for a shorter term must therefore be prepared. Accordingly, an Action Plan has been prepared which details the steps to be taken over the next four years to either acquire or to ensure the continued availability of new resources. It also includes strategies to address future risks and uncertainties associated with testing the 20-Year Outlook against the future conditions and uncertainties noted above.

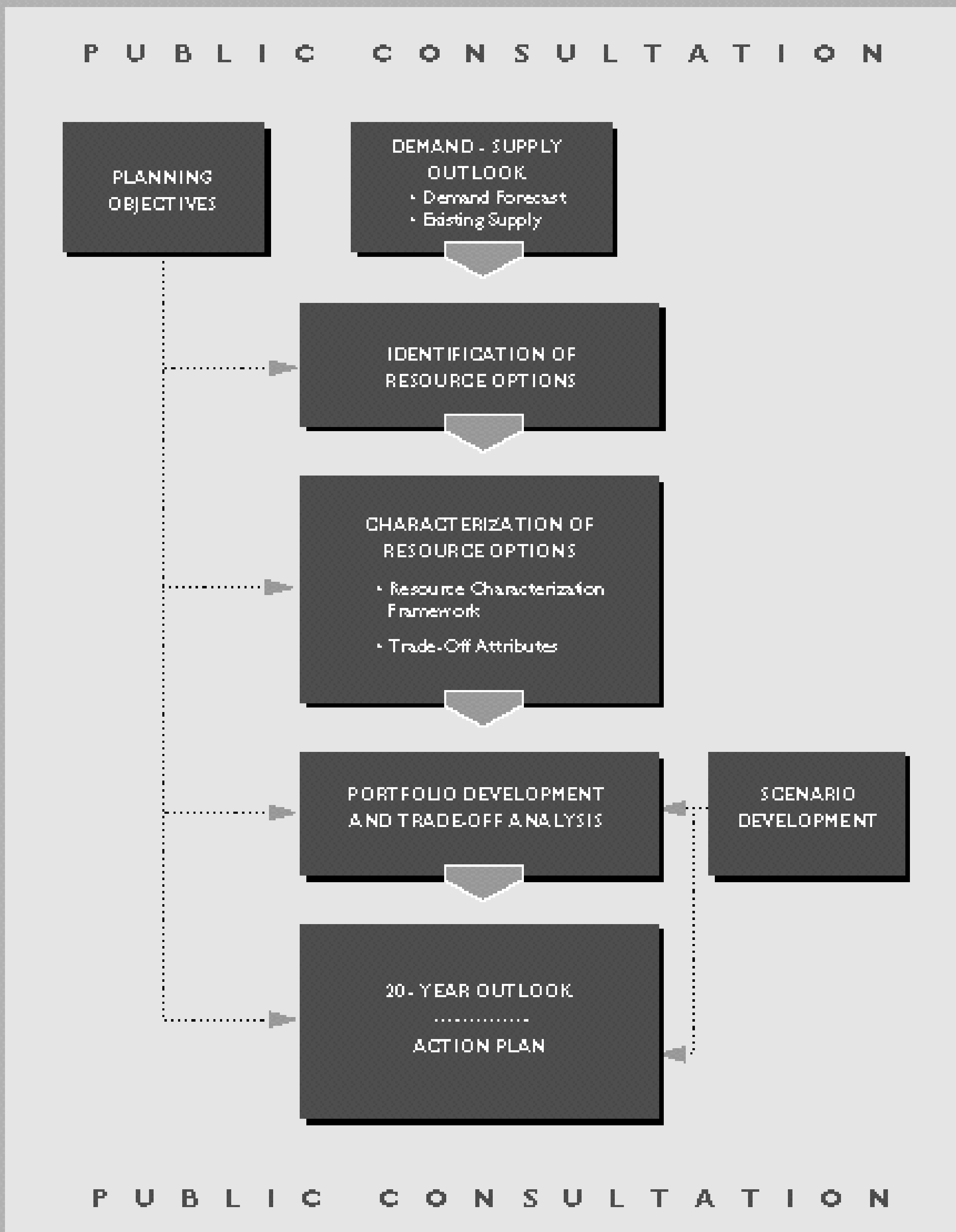
The key elements of the Action Plan are shown in Table 1.

Table 1:

Summary of Four-Year Action Plan

RESOURCES	ACTION	SCHEDULE
Generation (supply-side)		
Alternative Technologies	Continue to collect information,provide quarterly reports and annual updates of Resource Summaries.Support information exchange, research and demonstration projects if cost-effective.	Ongoing
Hydroelectric		
Stave Falls Powerplant	Continue licencing requirements and proceed with construction.	In-service 1999
Revelstoke Unit 5	Continue the Environmental Assessment Act licencing process.	Earliest in-service 1999
Seven Mile Unit 4	Continue the Environmental Assessment Act licencing process.	In-service 2000
Resource Smart	Continue cost-effective efficiency improvements at existing facilities.	Ongoing
Purchases		
Alberta Imports	Purchase when cost-effective and/or needed.	Ongoing
Alcan	Continue purchases.	Ongoing
Downstream Benefits	Continue discussions with the provincial government.	Ongoing
U.S.Imports	Purchase when cost-effective and/or needed.	Ongoing
Thermal		
Burrard Thermal	Install second selective catalytic reduction and associated upgrade work.	In-service 1996
	Continue investigation of repowering two modules.	Earliest in-service
	Continue full repowering investigations.	Future
	Continue investigations on fuel supply.	Underway
Private Sector		
December 1994 Request for Proposals	Negotiate with proponents for possible purchase of up to 300 MW if contract terms and pricing are satisfactory.	Underway
Demand-side		
Community Energy Planning	Involve municipal governments,planners,businesses and residents in energy aware community and land use planning.	Ongoing
Demand-Side Management	Continue current plans in the short term, recognizing that changes in the electricity market structure toward more competition may require a transition from rebates to fee-for-service and cost recovery.	Underway
Rates		
Wholesale Wheeling Rate	File wholesale wheeling rate.	By mid-November 1995
Industrial Service Options	Revise following consultation with industrial customers.	By late 1995
Power Exchange Operation	Review other alternatives.	By late 1995
Other Options	Continue to develop rate options and consult with customers on their rate options needs.	Underway
Transmission		
Interior to Lower Mainland		
American Creek Capacitor Station	Proceed with planning activities to uprate.	Underway
Second Nicola to Meridian 500 kV Transmission Line	Continue planning activities to ensure the availability of right-of-way to build a line, if required in the future.	Underway
Supply to Vancouver Island		
Malaspina to Dunsmuir Seventh 500 kV Cable	Continue investigation of seventh 500 kV cable.	Underway
Dunsmuir to Sahtlam Upgrade	Continue investigation to upgrade from 230 kV to 500 kV operation.	Underway
Distribution Automation	Continue cost-effective distribution automation.	Ongoing

CHAPTER 1
1995 INTEGRATED ELECTRICITY PLAN APPROACH



1 Integrated Electricity Plan Approach

1.1 Introduction

Electricity consumption in BC Hydro's service area is estimated to be growing at a rate of two percent per year. Over the next 20 years, the total increase in the annual demand for electricity is estimated to be 25,000 GWh of energy and 4,100 MW of capacity. This is approximately equal to the amount of electricity used by the Greater Vancouver region.

Meeting future electricity demand presents a challenge to BC Hydro. The electricity markets in British Columbia and throughout North America are in a period of transition. A shift to a more competitive market structure will affect the level of demand and the manner in which supply-side, demand-side and transmission resources are developed and managed. BC Hydro's planning must remain flexible and responsive to potential changes in the utility industry in order to continue to meet customer needs for reliable and cost-effective electricity service.

The *1995 Integrated Electricity Plan* presents BC Hydro's current perspective on the options available to meet the future electricity needs in its service area. The 'integrated' approach used to develop the 1995 Plan includes both supply-side and demand-side options and the associated bulk transmission (i.e., 500 kV) requirements. The planning process established broad objectives, evaluated possible resource plans against these objectives and specified actions required by BC Hydro to meet future customer needs for electricity.

The *1995 Integrated Electricity Plan* is comprised of two documents, namely this report and the appendices (bound separately).

1.2 Scope of the Plan

The Plan, developed with input from a group of external stakeholders, provides direction at the broad strategic level on the nature and quantity of resources that may be acquired over the next 20 years. Particular emphasis is placed on specific actions required over the next four years to implement the Plan.

The Plan is based on current information that will need to be tested to a greater extent and level of detail, taking into account the results of the current review of the electric utility industry in British Columbia, before specific commitments for major acquisitions or expansions are made. The Plan does not address issues specific to the acquisition or implementation of individual resource options. Rather, these issues are addressed as part of the licencing and regulatory process associated with each of the resource options.

Finally, the Plan takes into consideration a broad range of interests, including those of BC Hydro managers and electricity planners and a representative group of external stakeholders known as the Consultative Committee. These interests are reflected in the financial, technical, environmental, social/community and economic development attributes that have been incorporated into the planning process. Although the Consultative Committee provided valuable input, the *1995 Integrated Electricity Plan* is BC Hydro's responsibility.

1.3 The Planning Context

The Plan was developed during a period of transition in the electric utility industry in British Columbia. Since the start of the planning process in December 1994, there have been a number of developments that affected the Plan. These include a public review of the electricity market structure in the province, new legislation which affects the approval of electricity projects, proposals for private sector supply of electricity and the changing status of some resource options. Discussion on some of the factors or events that have affected the Plan are summarized in the following sections.

1.3.1 Electricity Market Structure Review

Electricity markets are going through a transition. In the past, BC Hydro focused its planning primarily on uncertainties associated with the level of future demand and the availability of resources to meet that demand. Today, changes in technology, global economies, the environment, open access, competition and public interests are increasing the level of uncertainty in electricity planning.

BC Hydro has traditionally been the primary provider of electricity in British Columbia, responsible for both generation and delivery of electricity to its customers. With independent power producers now in the generation market, BC Hydro has the option of developing its own resources or acquiring electricity from a variety of other sources. In addition, there is a trend towards open wholesale transmission access among utilities across North America. BC Hydro holds memberships in two regional transmission groups — voluntary organizations which facilitate the efficient use of existing transmission facilities and promote increasing transmission access. Finally, customers, particularly at the industrial level, are demanding a wider variety of services and pricing options.

The implications of these changes for the electricity industry in British Columbia are complex. In December 1994, the Provincial Government directed the British Columbia Utilities Commission (BCUC) to conduct a public review of the electricity market structure in British Columbia, to assist the Government in developing future electricity policy. The results of this review were released at the time this Plan went to press. Recognizing that changes could dramatically affect BC Hydro, the planning process has evaluated a range of risks and uncertainties in order to ensure that the Plan remains flexible to changing market conditions. The implications of changing electricity markets for planning is discussed in more detail in Chapter 9.

1.3.2 Provincial Independent Power Producer Policy

In October 1992, the Province issued a policy statement on the role of independent power producers (IPPs) as suppliers to BC Hydro. In general, the policy states that supply of electricity by IPPs would be encouraged where a need is identified and where they could provide real advantages in cost, innovation and expertise. IPPs would not be invited to bid on new large hydroelectric sites in undeveloped basins or on sites in basins already developed by BC Hydro.

THE LINKAGE BETWEEN THE INTEGRATED ELECTRICITY PLAN AND REQUESTS FOR INDEPENDENT POWER PROPOSALS

BC Hydro's Integrated Electricity Plan identifies resource options to meet the anticipated demand for electricity. Some of these options come from independent power producers .

Requests for Proposals (RFPs) are generally issued for the acquisition of resources from independent power producers. However, the Plan does not select specific independent power producer projects for acquisition.

The Integrated Electricity Plan supports the request for proposals by:

- *Identifying the need for power from outside the utility (i.e., the need for future request for proposals) and the broad parameters for the request for proposals (e.g., the amount of power needed).*
- *Suggesting a framework for evaluating possible resource options for consideration in the development of the Plan.*

The request for proposals supports the Plan by providing market information,including data on financial, technical, environmental, social/community and economic characteristics of resource options .

The request for proposals and integrated electricity planning processes generally follow one another, unlike the coincident time frames in the 1995 planning cycle.

In December 1994, BC Hydro issued a request for proposals (RFP) for private sector supply of electricity. The market information provided by the responses was used in development of this Plan.

1.3.3 British Columbia *Environmental Assessment Act*

On 30 June 1995, the Provincial Government proclaimed the *Environmental Assessment Act.* This Act combined three former review processes into a single process to assess the environmental, economic, social, cultural and heritage impacts of major projects. Although the Act does not govern the development and approval of integrated electricity plans, current Government policy guiding the application of the Act indicates that proposed domestic energy projects should be part of an approved integrated resource plan prior to application for project licences. Furthermore, electricity generation projects over 20 MW and transmission projects at or greater than 500 kV will require approval through the environmental assessment review process.

1.3.4 BC Hydro's *1994 Resource Acquisition Policy*

The *Resource Acquisition Policy* was developed to provide guidance on the evaluation of resources for acquisition. The policy includes a multiple account evaluation framework and a summary of how BC Hydro determines the need for new resources.

The multiple account evaluation framework has been used to guide the evaluation of resource options for the Plan. For example, the criteria used to evaluate resource options and to compare possible resource portfolios follow the individual accounts set out in the *Resource Acquisition Policy*. However, the Plan builds upon and, in some cases, goes beyond the *Resource Acquisition Policy* with a more specific treatment of environmental and social factors and a trade-off analysis framework to assist in decision making. A review of the *Resource Acquisition Policy* will begin in October 1995.

1.3.5 Regulatory Guidelines

The BCUC has established guidelines for integrated resource planning (IRP) that provide general direction and outline BCUC expectations for utilities in developing long-range plans and shorter-term action plans. The planning process used by BC Hydro for this Plan is consistent with the IRP guidelines and incorporates its key steps: the identification of planning objectives; preparation of a demand-supply outlook; public consultation; identification and description of resource options; portfolio development and trade-off analysis; and preparation of a 20-Year Outlook and Four-Year Action Plan.

1.3.6 Columbia Basin Accord

On 19 March 1995 the Province of British Columbia and the Columbia River Treaty Committee signed an agreement which will result in considerable investment in the communities of the Columbia-Kootenay region. As a result of the Accord, the Columbia Power Corporation (CPC) and the Columbia Basin Trust (CBT) will jointly consider the development of three power projects at existing dams in the region. The proposed projects include adding new generation at the Hugh Keenleyside Dam and expanding the generation capacity at the Waneta and Brilliant Dams. Although these projects are considered as resource options within this Plan, it is recognized that they would have to be offered to BC Hydro through a response to a future request for proposals.

1.3.7 Regional Transmission Groups

Regional Transmission Groups (RTGs) are voluntary organizations of transmission owners and users in North America to facilitate wholesale transmission access. Membership in regional transmission groups is open to transmission owners such as the traditional utilities as well as transmission users such as distribution utilities, independent power producers and marketers. Regional transmission groups provide for wholesale wheeling only; that is, no utility is required to wheel another supplier's electricity to its retail customers.

WHEELING:

The transmission of electric power from one system to another through a third party, usually the owner of the transmission facilities.

Retail Wheeling:

The wheeling of power from suppliers to customers.

Wholesale Wheeling:

The wheeling of power from suppliers to utilities.

BC Hydro and Powerex[1] have joined the Western Regional Transmission Association (WRTA) and Northwest Regional Transmission Association (NWRTA). In the short term this will provide wholesale wheeling access to electric utilities such as West Kootenay Power Ltd. This has the potential of reducing the demand for electricity, but it may on the other hand, provide opportunities for BC Hydro to supply electricity to additional utilities.

1.4 The 1995 Integrated Electricity Planning Process

The planning process for the Plan is shown in Figure 1.1. The integrated planning process followed a series of steps from identifying the need for new resources to setting objectives, identifying and evaluating options and finally selecting options that address both the short-term and long-term demand for electricity.

An important aspect of the resource evaluation was the need to carefully assess the implications of potential changes in market structure. To address this, numerous resource portfolios were developed and subjected to risk and uncertainty analysis to test their performance under changing conditions, such as high or low demand for electricity. Steps in the planning process are briefly described in the following discussion.

1.4.1 Public Consultation

In the past, BC Hydro has sought comments from the public on its Electricity Plans. For this Plan, a more direct approach to public consultation was implemented. A Consultative Committee was established to provide focused stakeholder advice to BC Hydro. This Consultative Committee was comprised of representatives from residential and industrial customer groups, individuals representing environmental interests, regional interests, BC Hydro, a sector of those industries, groups and individuals dependent upon natural resources (e.g., the fishing industry, recreational uses), and the Independent Power Association of British Columbia. The group met for a total of 24 days over a nine-month period.

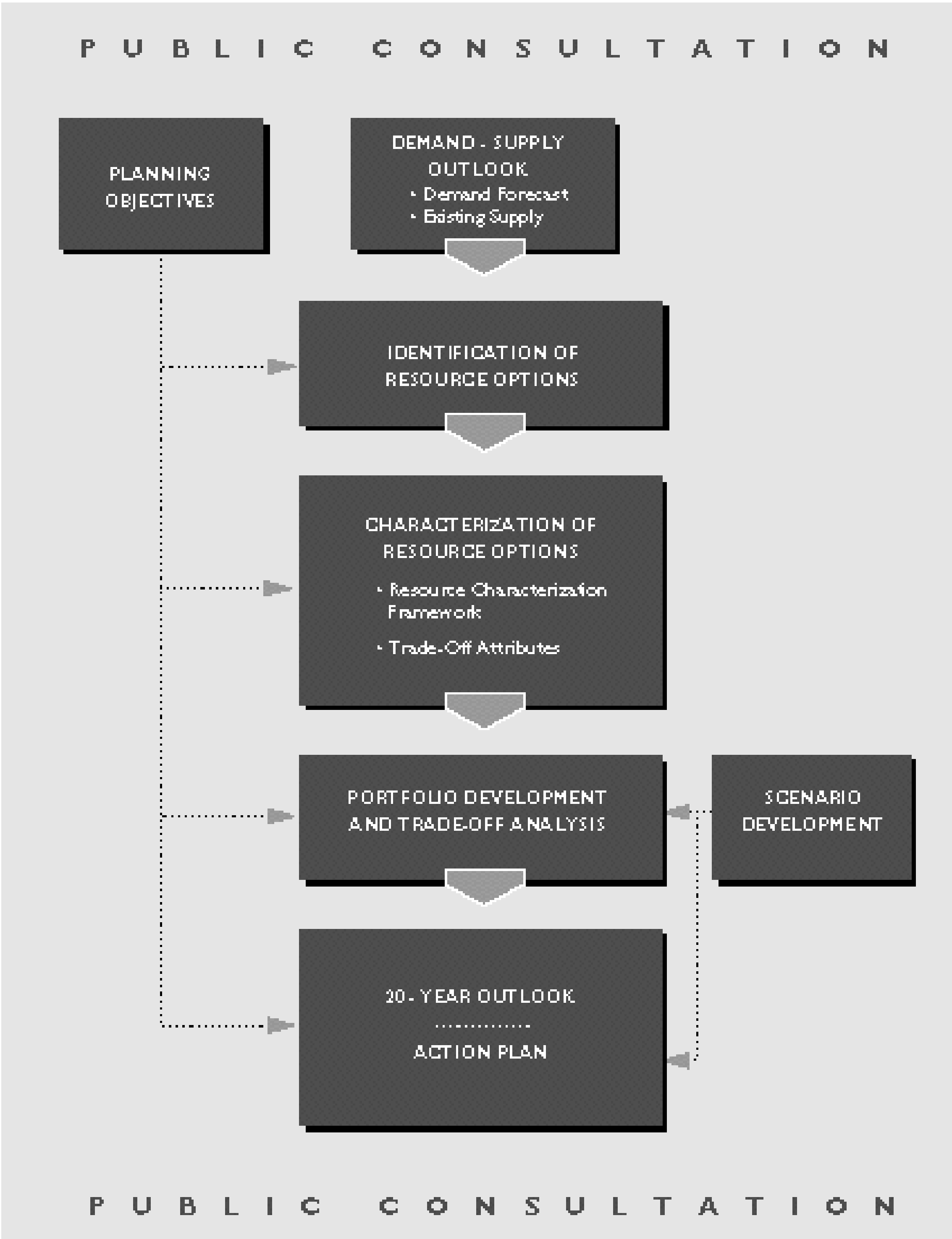
The consultation pertained to all steps in the integrated electricity planning process. The meetings focused on presentations and discussion of topics related to each step in the planning process. The advice received from the Consultative Committee was considered in decisions made at each step in the planning process, including the selection of a preferred portfolio of resources. A detailed description of the public consultation process is presented in Chapter 2. The results of the consultation for each step in the planning process are incorporated in the respective chapters in the Plan.

In addition to external stakeholder input, an internal BC Hydro consultation and review process was implemented to ensure that all interests were reflected in planning decisions. An internal BC Hydro stakeholder group, comprised of senior managers, participated in the same portfolio development and trade-off analysis process as the Consultative Committee. Recognizing that BC Hydro is ultimately responsible for the development and content of the Plan, the results of both the internal and Consultative Committee consultations were reviewed by the planning team to arrive at a final recommended portfolio for the *1995 Integrated Electricity Plan*.

1 Powerex is responsible for the purchase, sale and exchange of electricity between British Columbia, the western provinces and the western United States. In addition, Powerex assists British Columbia industry and independent power producers in the electricity trade marketplace.

FIGURE 1.1:

Steps in Preparing The 1995 Integrated Electricity Plan



1.4.2 Demand-Supply Outlook

The demand-supply outlook compares the forecast demand for electricity with the existing supply of electricity. Each year BC Hydro develops a range of demand forecasts for both energy and capacity. These forecasts cover a 20-year period and reflect assumptions about population growth, economic activity and the intensity of various electricity end uses, among others. Demand forecast figures from the *Electric Load Forecast 1994/95 –2014/15* were used to identify the energy and capacity requirements to be addressed by this Plan.

Determining the supply of electricity requires an inventory and consideration of all existing resources to determine the amount of energy and capacity available to meet future electricity needs, taking into account transmission constraints. The difference between the demand forecast and the existing system capability defines the scope of the Plan, keeping in mind that demand may change with changes in the electricity market structure. A detailed discussion of the demand-supply outlook is presented in Chapter 3.

1.4.3 Planning Objectives

Once the need for new resources is identified, planning objectives can be established. The objectives provide the basis on which to describe, evaluate and select portfolios. This year's objectives were based on corporate policies and input from the Consultative Committee and BC Hydro senior managers. A detailed discussion of the objectives is presented in Chapter 4 and a review of the 20-Year Outlook relative to the objectives can be found in Chapter 7.

RESOURCE

A program, facility or purchase to meet electricity needs by providing new supply or changing the demand for electricity.

1.4.4 Identification and Characterization of Resource Options

Athree-step process was used to develop resource options:

- identifying possible resources and resource types that could help meet future demand;
- identifying attributes (criteria) by which to evaluate different resources; and,
- characterizing (describing) each resource in terms of the attributes.

Individual resource options came from a variety of sources including past Electricity Plans, the December 1994 Request For Proposals for private sector power, input from the Consultative Committee and new research. Resources were grouped into three categories: generation; demand-side; and transmission. Generation resources include hydroelectric, thermal and alternative technologies. Demand-side resources include demand-side management, rates and community energy planning. Transmission resources include the transmission lines and substations at the bulk transmission (e.g., 500 kV) level.

In order to determine the suitability of each resource for inclusion in the Plan, and to ensure consistent and fair treatment of all options, a master list of attributes was developed. This list is the Resource Characterization Framework (RCF). The RCF is a comprehensive set of attributes divided into five categories: financial, technical, environmental, social/community and economic development. These attributes in turn, contributed to a smaller set of twelve trade-off attributes, used to evaluate resource portfolios at a planning level.

The RCF and trade-off attributes were then applied to each resource or portfolio to identify relative strengths and weaknesses. This process is referred to as characterization. A more detailed discussion of resources, the RCF and trade-off attributes and characterization is presented in Chapter 5.

1.4.5 Portfolio Development and Trade-Off Analysis

To evaluate a full range of options, BC Hydro and the Consultative Committee developed over 40 different portfolios. Each portfolio was analyzed to compare its performance on the trade-off attributes and to other portfolios. The initial analysis identified some portfolios that performed poorly on all attributes relative to other portfolios and therefore were not considered in further analyses.

After lengthy discussion and analysis, the number of portfolios was gradually reduced to two portfolios: the Consultative Committee's recommended portfolio and subsets and BC Hydro's selected porfolio. A detailed discussion of the portfolio development and trade-off analysis is presented in Chapter 6.

PORTFOLIO:

A group of resources acquired in a sequence to meet the 20-year demand forecast.

1.4.6 Scenario Development

Risk and uncertainty can have significant implications for acquiring resources. These risks may be related to the level of demand, resource availability, regulation or factors that affect supply from new or existing resources. To assess the risks, scenarios were constructed and used to test selected portfolios to examine their performance under a variety of conditions. Scenarios are discussed in Chapter 7.

1.4.7 20-Year Outlook and the Action Plan

The 20-Year Outlook and the Four-Year Action Plan present BC Hydro's proposed strategy to meet the future electricity needs of its customers.

The 20-Year Outlook identifies the selected portfolio of resources to be acquired between 1995 and 2014 to meet the Probable Demand Forecast. The selected portfolio is based on the results of the portfolio development, trade-off analysis and scenario analysis. However, it is important to recognize that significant commitments based on a 20-Year Outlook cannot be made due to the changing nature of the industry. Thus the resources identified over the longer term, as well as the Probable Demand Forecast, must be continually re-evaluated to ensure that BC Hydro is responsive to changing market conditions.

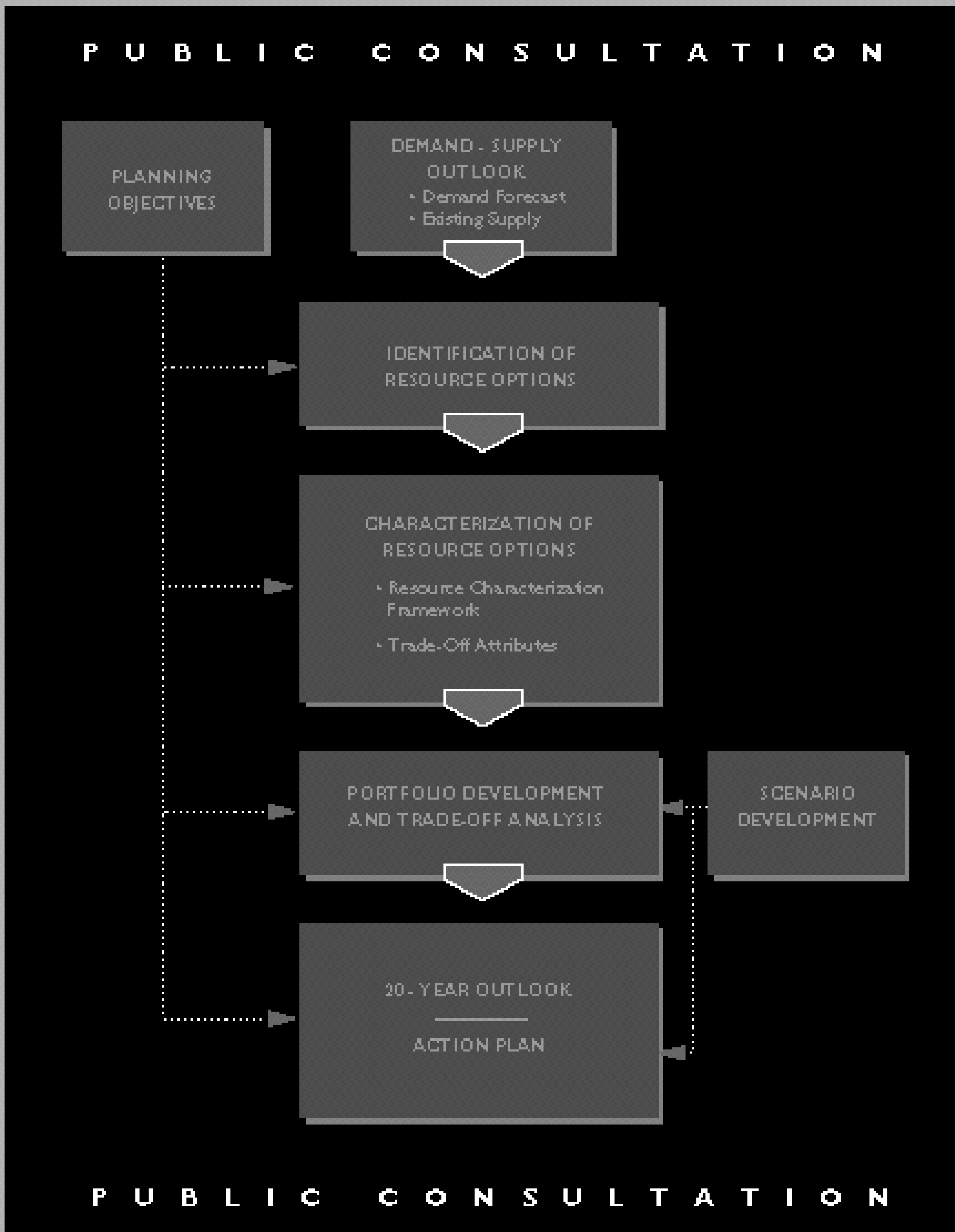
The Four-Year Action Plan describes the activities required over the next four years to match resources with probable demand in BC Hydro's service area or to preserve the availability of those resources. It also includes strategies to address risks and uncertainties in providing electricity service.

The 20-Year Outlook is presented in Chapter 7, and the Four-Year Action Plan is presented in Chapter 8.

1.5 Report Format

The following chapters provide a detailed discussion of each step in the integrated planning process, culminating in a discussion of the selected portfolio in the 20-Year Outlook and the Four-Year Action Plan. Each chapter contains a more detailed description of planning activities, the research and analysis undertaken and a summary of the results and their implications for the Plan. Many Consultative Committee recommendations have been incorporated in the development of the Plan.

CHAPTER 2
PUBLIC CONSULTA TION



2 PUBLIC CONSULTATION

2.1 Introduction

For the planning process, a Consultative Committee was convened to provide a forum for focused stakeholder consultation on issues related to the Plan. The consultation process fostered greater awareness and understanding of both BC Hydro and stakeholder interests and the decisions adopted in this Plan.

This chapter describes the consultation approach. It addresses the role and composition of the Consultative Committee, the meeting schedule, the meeting format and supporting communication activities. The advice received from the Consultative Committee is not contained in this section, but is reflected in the decisions made in each step of the process, as discussed in later chapters.

Appendix A includes background information related to the establishment and operation of the Consultative Committee, including detailed notes of the Consultative Committee meetings. Consultative Committee member comments on the Plan and the process by which it was developed are presented in Appendix B.

2.2 Background

Public consultation at BC Hydro occurs in three main areas: projects, operations and planning. BC Hydro has engaged in project consultations (e.g., Burrard Thermal Upgrade Project), some consultation on operations (e.g., Electric System Operations Review) and some planning-related consultations (e.g., Lower Mainland Electricity Choices).

BC Hydro had planned a provincial workshop for 03 December 1994 to determine how best to proceed with a consultation process for integrated planning. The objectives of the workshop were to identify the role of public consultation in BC Hydro's electricity planning process and to suggest alternative processes by which input could be obtained.

Just prior to the planned workshop, the British Columbia Utilities Commission's 24 November 1994 decision on BC Hydro's 1994/95 Revenue Requirements Application directed BC Hydro to establish a Consultative Committee to provide advice to BC Hydro on its 1995 electricity plan. Therefore the workshop was canceled. The Commission further directed BC Hydro to submit its integrated resource plan by 30 June 1995 (subsequently revised to 30 September 1995). Given this time constraint, the scope of public consultation was limited to the Consultative Committee and activities supporting that group.

2.3 The Consultative Committee

2.3.1 Role of the Consultative Committee

The Consultative Committee was established to provide advice to BC Hydro on the development of the Plan. The Consultative Committee met with BC Hydro for 24 full day sessions and was directly involved in discussions related to each step in the planning process. The advice provided by the Consultative Committee has been valuable in developing the Plan, and the investment of Consultative Committee members' time and resources is acknowledged and appreciated.

2.3.2 Consultative Committee Composition

In December 1994, BC Hydro established the Consultative Committee according to the membership defined in the British Columbia Utilities Commission's decision. That decision stated the following: *"...The Commission directs BC Hydro to ask the organizations represented on the DSM collaborative if they wish to be members of the new consultative committee. In addition, BC Hydro should invite IPP representation. The Utility may also augment the committee by adding representation from one or two other groups, if it so desires."*[1]

BC Hydro added regional representatives and, at the request of the Consultative Committee, later added a Natural Resources Dependent sector representative. Regional interests were added because of the implications of regional issues (e.g., growth, environmental standards) for electricity planning, the growing importance of community energy planning and the need to provide a 'window' for groups or individuals not necessarily aligned or in contact with the DSM Collaborative sector representatives.

Despite numerous efforts, representation from the commercial customer sector, the aboriginal community, the Union of BC Municipalities (UBCM) and the Vancouver Island region could not be obtained. The time commitment required to attend meetings and review information was often cited as a major barrier to their participation.

A few organizations and individuals asked for representation on the Consultative Committee. These requests could not be accommodated due to the specific nature of the British Columbia Utilities Commission directive regarding the Consultative Committee membership, or because the organization had a limited focus of interest which was not appropriate for a broad planning exercise. The final composition of the Consultative Committee is shown in Table 2.1.

Consultative Committee members were approached on the basis that they would represent their particular area of interest or, in the case of regional representatives, regional interests. In some cases representatives identified an alternate to participate on their behalf when circumstances prohibited attendance at meetings. From the outset, Consultative Committee members were encouraged to keep their constituents well informed of the planning and consultation process and to seek input on discussion topics. The support provided by BC Hydro to assist Consultative Committee members with communications is summarized in Section 2.5.

A summary of the process by which the Consultative Committee was established is included in Appendix A, as is a complete list of Consultative Committee members.

2.3.3 Observers

Observers at Consultative Committee meetings included representatives from the following organizations: British Columbia Utilities Commission, BC Gas, Greater Vancouver Regional District-Air Quality Department, West Kootenay Power and the Ministry of Energy, Mines and Petroleum Resources.

1 British Columbia Utilities Commission, *Decision and Order No.G-89-94 on British Columbia Hydro and Power Authority Application – 1994/95 Revenue Requirements*, Nov. 1994, pp. 57-58.

2.3.4 Consultative Committee Chair/Facilitator

An independent chair/facilitator was selected by the Consultative Committee to facilitate the meeting discussions. The facilitator worked closely with the integrated electricity planning team to develop meeting agendas and information materials and was responsible for facilitating the Consultative Committee's discussion on agenda topics.

2.3.5 Terms of Reference and Operating Understandings

To assist the Consultative Committee, BC Hydro prepared an initial draft terms of reference and the Chair prepared a draft set of operating understandings. Both were finalized by the Consultative Committee at their first two meetings and subsequently used to guide the consultation process. These are included in Appendix A.

2.4 Summary of Meetings

The Consultative Committee met from January 1995 through to September 1995. In total, the Consultative Committee met for 24 days over the nine-month period, once or twice a month depending on the status of the Electricity Plan work program. Table 2.2. provides a summary of the key discussion topics.

In addition, a two hour meeting was held on May 1, with local members in attendance and some out-of-town members on conference call, to discuss the proposed extension to the June 30 date for submission of the Plan. Members were also invited to the Economic Planning Workshop held on June 7, which provided information and opportunity for input on the load forecast process. A discussion session on issues to be considered in developing the forecast was held on August 17.

All Consultative Committee members, alternates and observers received information packages for each meeting and additional material was provided at the meetings. Detailed discussion notes were taken to ensure that advice from the Consultative Committee was accurately

Table 2.1:

Consultative Committee Representation

INTEREST REPRESENTED	MEMBERSHIP
Residential Customers	Two members, represented by the Public Interest Advocacy Centre (PIAC) and the Kootenay-Okanagan Electric Consumers' Association.
Industrial Customers	Two members, represented by the Council of Forest Industries (COFI) and the Mining Association of BC.
Regional Representatives	Three members, represented by the Prince George Region Development Corporation,the Kootenay Regional Advisory Group (KRAG) and the Greater Vancouver Regional District (GVRD).
Environmental Interests	Two members, represented by the BC Energy Coalition and the Slocan Valley Watershed Alliance.
Independent Power Producers	One member, represented by the Independent Power Association of BC.
Natural Resources Dependent Sector	One member, represented by the United Fishermen and Allied Workers' Union.
BC Hydro	Two members, represented by Power Supply and Customer Services.

Table 2.2:

Summary of Consultative Committee Meetings

(Bold indicates further information available in relevant chapters)

MEETING DATE	KEY DISCUSSION TOPICS
January 26 & 27	Consultative Committee Composition/Membership BCUC Decision Project Plan Overview Consultative Committee Role and Operation President and CEO Opening Remarks Objectives: Introduction
February 9 & 10	Demand-Supply Outlook Objectives Workshop Resource Options: Development of Inventory Screening Criteria Consultative Committee Membership
February 27 & 28	The Plan Approach Resource Options: Pre-screening/Sorting IPP Request for Proposals Resource Options: Introduction to Resource Characterization Framework Consultative Committee Membership
March 9 & 10	Electricity Market Structure Review Resource Options: Inventory Sorting Criteria Resource Options: Financial Analysis and Modeling; Social and Environmental Update Scenario Development Communications with Sector Constituents
March 23 & 24	Consultative Committee Membership/Selection Process Trade-off Analysis: Introduction Resource Options Scenario Development
April 6 & 7	Trade-Off Analysis: Trial Runs Public Consultation:Best Practices Study Scenario Development
May 5	Extension to BCUC date for Plan submission Scenario Development Resource Options: Demand Side Management Trade-Off Analysis
June 8 & 9	Revised Plan Work Program IPABC presentation on Financial Evaluation Portfolio Development IPP Social Evaluation Report Update Electric and Magnetic Fields Effects
June 27 & 28	Alternative Technologies Presentation Resource Characterization Attributes Portfolio Development IPP Social Evaluation Report Public Consultation Integration
July 20 & 21	Portfolio Review and Analysis Presentation on Air Emissions Report Outline Electricity Plan
August 17 & 18	Portfolio Development Scenario Analysis of Final Portfolios Resource Acquisition Policy Work Plan Review of BCUC Directives
September 25	Review of the draft Electricity Plan
October 12 & 13	Review of the Consultation Process Review of the Resource Acquisition Policy

documented, drafts of which were reviewed with the Consultative Committee prior to finalization. Copies of the meeting notes can be found in AppendixA.

Consultative Committee meetings were coordinated by BC Hydro staff and facilitated by the independent chair/facilitator selected by the Consultative Committee. Meetings generally ran from 8:30 a.m. to 4:30 p.m. and were held at BC Hydro's Dunsmuir or Edmonds office.

The meeting format followed an agenda developed by BC Hydro in consultation with the Consultative Committee chair/facilitator. For each meeting topic, information was provided to Consultative Committee members in advance and presentations were made by BC Hydro, followed by an interactive discussion to obtain specific advice on planning issues.

2.5 Communication Activities

BC Hydro communication activities for the Plan focused on support to the Consultative Committee and their constituents. Activities included:

- Presentations on subjects of interest to the Consultative Committee such as alternative technologies, air emissions and electric and magnetic fields.
- Providing information to Consultative Committee members and their constituents, including the distribution of information packages and coordination of conference calls between Consultative Committee members and their constituents.
- Establishing and managing an electronic bulletin board system (BBS) to provide information to Consultative Committee members, alternates and observers. Members could also exchange information using the BBS. The BBS proved to be a more timely alternative to sending information by courier or through the postal system, particularly for those participants outside the Lower Mainland.

In addition, responses to over 30 public and interest group requests for information and presentations on the Plan and the process were provided.

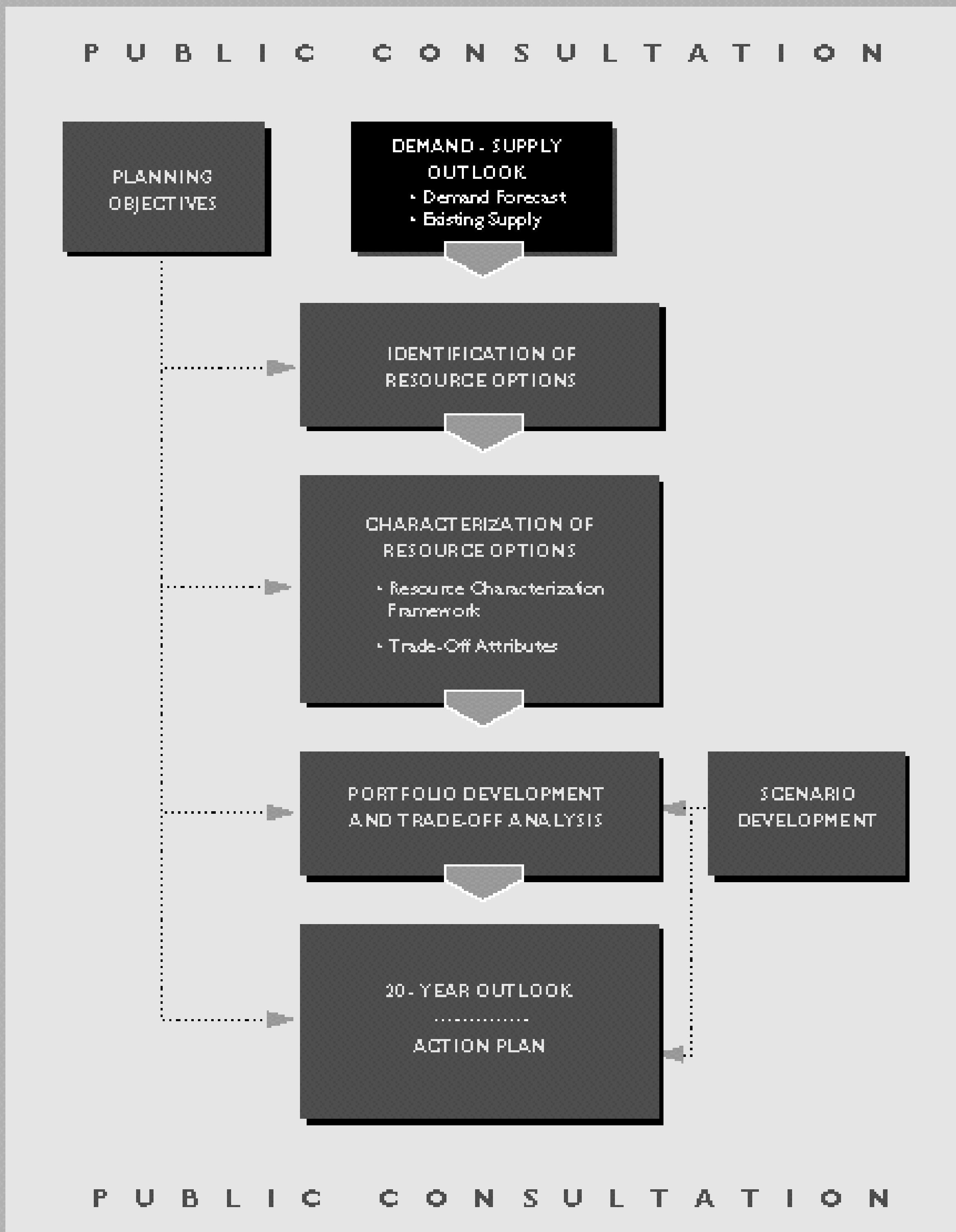
2.6 Public Consultation Integration

In the fall of 1994, BC Hydro initiated an assessment of its public involvement programs. The study explored the effectiveness of BC Hydro's approach and techniques used in public involvement at three levels: projects, operations and planning. Within the context of current consultation trends, the study provides recommendations on improvements to BC Hydro's consultation programs. The results of the study were presented to the Consultative Committee at its April 06 and 07 meeting. The study's recommendations are currently being implemented and are expected to result in cost efficiencies and improved synergy across BC Hydro's consultation spectrum.

2.7 Summary

Public input to the Plan was derived from the Consultative Committee, established in accordance with the BCUC directive. The Consultative Committee worked intensively over the nine-month period during which the Plan was developed and provided advice on each step in the planning process. This advice is reflected in following chapters. The appropriate time frame and diversity of interests for effective public consultation will need to be addressed in future consultations on electricity planning issues.

CHAPTER 3
DEMAND-SUPPLY OUTLOOK



3 DEMAND-SUPPLY OUTLOOK

3.1 Introduction

The demand-supply outlook refers to the balance between the demand for electricity in BC Hydro's service area and BC Hydro's ability to serve that demand using the existing system and new resources. Over the next 20 years, annual electricity requirements are forecast to grow by 25,000 GWh of energy and 4,100 MW of capacity (peak demand).

CAPACITY (PEAK DEMAND):

The maximum amount of electricity necessary at any given moment, or the maximum rate of supply of energy.

The electric system must produce and distribute sufficient electrical power at any one moment in time while maintaining a margin of safety for equipment maintenance and unscheduled outages on critical system components. This is analogous to the maximum rate of supply (cubic feet/second or gallons/minute) a municipal water system can provide at any one instant, which, in turn, depends on the water intakes at the storage reservoirs, water mains, etc.

Capacity is measured in kilowatts (one kW = 1,000 watts) or megawatts (one MW = 1,000,000 watts).

ENERGY:

The electric system must produce and distribute sufficient electrical energy to meet annual requirements. This is analogous to the total quantity of water (cubic feet or gallons) a municipality requires over a year.

Energy is measured in kilowatt hours (kWh).

A kWh is the average kilowatts demanded in one hour. For example, there are 8,760 hours in a year, so 1 MW demanded constantly for one year would be 8,760,000 kWh or 8.76 gigawatt hour (GWh). (One GWh = one million kWh.)

BC Hydro plans its electric system to meet the total annual energy demand with an acceptable level of reliability and to have sufficient dependable capacity to meet the probable instantaneous peak demand during the year[1]. To meet peak demand, BC Hydro must account for planned or unplanned outages of supply sources. This means the system must include a generation reserve margin of approximately 12 percent of installed system capacity. This 12 percent reserve provides a 'loss of load expectancy' of one day in 10 years, as required by the Western Systems Coordinating Council (WSCC) criteria for in-stalled and planned generating capacity. In the planning process, resources may also be advanced ahead of reliability requirements to reduce the expected long-term cost of serving demand.

The demand for electricity and the sources of supply have a strong influence on BC Hydro's planning. With most of the demand occurring in the southwest corner of the province and most of the supply located in the north and south interior regions of the province, an extensive system of transmission lines is required to transmit the electricity from the point of generation to the point of use. Transmission requirements are an important consideration in determining where best to locate new resources.

The discussion of the demand-supply outlook is presented in three sections: Section 3.2 outlines the current 20-year demand forecast; Section 3.3 provides an overview of the existing BC Hydro system, including existing supply sources and transmission issues; and Section 3.4 defines the amount of additional electricity supply to be addressed by this Plan.

3.2 The Demand Forecast

The demand forecast estimates future demand for electricity. BC Hydro prepares a range of forecasts, assuming 'high', 'probable' and 'low' growth rates. These three estimates translate into high, probable and low forecasts for demand over the 20-year planning horizon. The Integrated Electricity Plan uses the probable forecast to estimate the

1 Peak demand typically occurs on the coldest weekday of the year between 5:00 p.m.and 6:00 p.m.

PLANNING CRITERIA:

The energy reliability criterion requires that the expected amount of unserved energy demand in any given year must be less than 0.8 percent of the total annual energy demand.

The peak reliability criterion requires that expectation of having insufficient generating resources available to meet the forecast daily peak load should be one day in 10 years, or less.

resources required to meet the demand, but as outlined in Chapter 7, scenarios for high and low forecasts have also been explored.

Electricity consumption in BC Hydro's service area is estimated to grow at a rate of over 2 percent per year for the next 20 years. At this rate of growth, demand for electricity will double by the year 2030.

Each year BC Hydro updates its forecast for future energy and capacity requirements. The forecast is derived from many types of information including outlooks for: the provincial economy, expected population growth, trends in electricity consumption, regional economies, industry perspectives and world crude oil and natural gas prices. For this Plan, the electricity demand forecast from the *Electric Load Forecast 1994/95 – 2014/15* was used. This document can be found in Appendix D.

As part of the development of its annual forecasts, BC Hydro holds a one-day economic planning forum to obtain input on major assumptions underlying the forecast. While the 1994/95 demand forecast was developed prior to the start of this planning process, Consultative Committee members had the opportunity to attend the forum for the 1995/96 forecast. Some members of the Consultative Committee also accepted an invitation to participate in a session with BC Hydro staff to provide input on the preliminary development of demand scenarios for next year's forecasting cycle.

3.2.1 Factors Influencing Demand

Some of the factors that are used to forecast the expected level of electricity demand in British Columbia are summarized in the following discussion:

- Over the next twenty years British Columbia's population is expected to increase from 3.6 million to 5 million at a declining growth rate of 2.9 percent to 1.3 percent per year. This is above the Canadian average population growth rate.
- British Columbia is expected to benefit from increased world markets for primary resources as a result of the rapid increase in global population, expansion of international trade and the upgrading of living standards and infrastructure in developing regions.

Looking at the factors influencing demand for electricity by sector:

RESIDENTIAL

Increasing numbers of electric appliances and home office equipment is expected to keep residential electricity demand high over the 20-year horizon of this Plan. In the future, overall residential demand per household in British Columbia is expected to level off, mainly because increased demand will be offset by advances in energy-efficient building technology, higher density housing and improved energy efficiency in major appliances.

COMMERCIAL

Requirements for more housing, new and expanded sevices to support larger populations, increased tourism and international trade and the need for additional transportation infrastructure will all contribute to growth in commercial electricity demand. The use of electronic technologies to enhance commercial sector productivity and competitiveness is expected to continue.

INDUSTRIAL

Industrial electricity demand will grow more slowly than in the past. Although the global market continues to expand, growth in British Columbia's primary resource industries is expected to be constrained by limits on primary resource availability. Land use decisions and reductions in timber harvest levels will restrict growth of British Columbia's wood manufacturing and pulp and paper sectors. Metal mining will be constrained by land-use issues, exhaustion of developed reserves and limits on exploration for new ore bodies. In response to primary resource constraints, British Columbia industry is expected to shift to more value-added production, ship less commodity-grade product and adopt production processes that make more efficient use of primary resources. These changes in product mixes and production processes, as well as the addition of pollution-control devices and more automation in general, will be the main sources of growth in industrial electricity demand.

3.2.2 Types of Forecasts

Three types of forecasts are developed each year to analyze different factors influencing demand: a Reference Forecast; a Probable Demand Forecast; and a Probable Load Forecast.

REFERENCE FORECAST

This electricity demand forecast is based on economic projections and population forecasts and assumes that real (net of inflation) electricity rates will continue at current levels. Changes in the Reference Forecast reflect new assumptions about population growth, economic trends and electricity consumption patterns. Demand-side management programs are not included in these assumptions. However this forecast does include estimated transmission losses[2] because BC Hydro must plan sufficient resources to not only meet the estimated customer demand but also account for the loss of electricity due to resistance in the transmission lines.

PROBABLE DEMAND FORECAST

The Probable Demand is the electricity demand forecast on which this Plan is based. It incorporates the rate effect, or price elasticity, of the Reference Forecast, as described below.

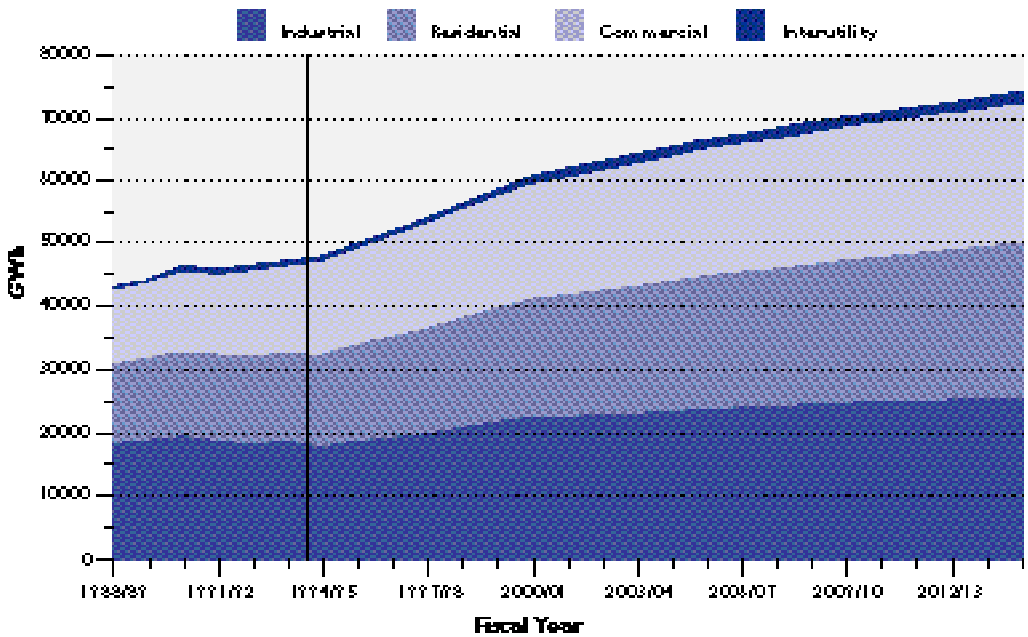
Starting with the Reference Forecast, the cost of new resources required to meet that demand forecast is calculated. The revenue required to pay for these new resources is then determined. These additional revenue requirements are translated into rates for customers. If the result is increased rates, this could drive demand down. Alternatively, if rates decrease, consumption of electricity could increase. This change in consumption patterns is known as the price elasticity effect. The Probable Demand Forecast also looks at various scenarios associated with trends in customer demand. An example of one such scenario is the effect of increased use of electric vehicles on the demand forecast.

Figure 3.1 shows the Probable Demand Forecast for energy over the next twenty years. By the year 2014/15 annual energy requirements are forecast to increase by 25,000 GWh and capacity requirements by 4,100 MW over the forecast demand in 1994/95. The residential sector is expected to account for 34 percent of the projected growth in electricity demand; the commercial sector for 39 percent; and the industrial sector for 27 percent.

2 The estimated transmission capacity losses amount to about 8 percent of the total system net capacity demand less demand-side management (equivalent to about 1,000 MW by the year 2014/15,as per Table 7.1 of Appendix D). The estimated transmission energy losses amount to about 10 percent of total system net energy demand less demand-side management (equivalent to about 7,000 GWh by the year 2014/15,as per Table 2.1 of Appendix D).

Figure 3.1:

The Probable Energy Demand Forecast by Sector



The forecast probable demand in 2014/15 is 13,300 MW, which is approximately 4,100 MW higher than the forecast for 1994/95. BC Hydro's existing system currently contains approximately 400 MW more supply than the estimated demand for 1994/95 and so the resources required to meet the demand for capacity in 2014/15 is 3,700 MW.

PROBABLE LOAD FORECAST

The Probable Load Forecast is calculated by subtracting the estimated reduction in demand resulting from demand-side management programs from the Probable Demand Forecast. Generally, the Probable Load Forecast represents the net load that BC Hydro must meet with supply-side resources.

3.2.3 Regional Electricity Requirements

The potential for increased competition in the generation of electricity along with improvements in local energy generation technology and community energy planning have increased the need to understand regional electricity requirements. Distribution loads (largely residential and commercial customers) and transmission loads (mainly industrial customers) are expected to grow at significantly different rates between regions.

The increase in residential and commercial development as a result of the projected high population growth in Lower Mainland suburbs, as well as north and central Vancouver Island, will continue to drive the demand for electricity in these regions.

In northern British Columbia, mining and mechanical pulping and paper production facilities are expected to drive industrial demand. The Annual Allowable Cut (AAC) restrictions will not be as severe in northern British Columbia and may be partially offset by increased harvesting of hardwoods. Industrial growth will be slower in other regions due to land use constraints, AAC restrictions and limitations on new mining activity.

3.2.4 Forecasting in a Changing Marketplace

BC Hydro has traditionally planned resources to meet the demand for electricity in its service area. In a competitive marketplace, it is still necessary to estimate the total demand for electricity, in order to know the size of the market. For BC Hydro, this could mean estimating its market share, quantifying the competition for that market share, segmenting the market and determining the relative profitability of each segment. The challenge for demand forecasting will therefore be to expand the current activities to consider new factors important in a more competitive marketplace.

3.3 Overview of the System

With 42 reservoirs and 29 hydroelectric stations, the majority of energy generated in BC Hydro's system is from hydroelectric sources. BC Hydro currently has contracts with a number of independent power producers. BC Hydro also owns and operates Burrard Thermal, a gas-fired conventional thermal plant in Port Moody. On northern Vancouver Island, BC Hydro has the 100 MW, oil-fired Keogh generating station. This facility has limited fuel storage capacity and operates mainly on a standby basis to meet system emergencies and reserve requirements on Vancouver Island. In Prince Rupert, BC Hydro has a 46 MW, gas-fired combustion turbine station, which is used mainly for standby. BC Hydro also has three small diesel stations on the integrated system which are used mainly on a standby basis. The combined dependable generating capacity for the integrated system is approximately 9,900 MW of dependable capacity (Table 3.1). Figure 3.2 shows a map of BC Hydro's generating stations, major substations and 500 kV transmission lines.

The hydroelectric resources in BC Hydro's system rely primarily on annual stream flows from melting snowpack to fill the reservoirs. Since stream flows vary from year to year, it is important that BC Hydro determine the capability of the system during critical water conditions the lowest stream flow sequence on record. Currently the critical period is based on stream flow conditions from October 1940 to April 1946. During better stream flow periods (about 80 percent of the time) secondary (non-firm) energy is available. This secondary energy can significantly increase the energy output from the existing system.

BC Hydro system runoff is estimated at 94% of normal for the February to September 1995 period. Domestic load was below forecast during 1994-95 for a variety of reasons. Export markets were depressed during 1994-95 due to the end of the drought in the U.S. Columbia River system and price reductions for gas-fired energy. Finally, the return of stored energy to other utilities was lower than expected due to the extended fish flow operation on the U.S. Columbia River. The combination of all these factors caused BC Hydro total system storage to refill to 93.3% of full on 31 August 1995, the highest level since 1984. After adjusting for foreign storage in the system, BC Hydro net system storage on 31 August was 83.8% of full. Assuming average water conditions for 1995-96, BC Hydro system storage is expected to remain healthy.

Table 3.1

Energy and Capacity of Existing Supply-Side Resources

RESOURCES	CAPACITY (MW)		CAPABILITY (GWH)	
	Nameplate	Dependable	Average	Firm
Existing Hydroelectric [3]				
G.M.Shrum	2416.0	2680	13425	12630
Peace Canyon	700.0	600	3355	3255
Mica	1736.0	1600	7445	6730
Revelstoke	1843.0	1800	8350	7745
Seven Mile	607.5	550	3365	2875
Kootenay Canal	529.2	532	3280	2430
Bridge River	428.0	480	2670	2725
Cheakamus	140.0	144	910	845
John Hart	120.0	126	900	875
Jordan	150.0	170	250	195
Ruskin	106.0	105	380	325
Others[4]	555.9	546	3000	3540
Subtotal	9331.6	9333.0	47330.0	44170.0
Existing Thermal				
Burrard[5]	927.5	40	6900	6900
Gas Turbines	145.7	160	550	550
Diesels	10.9	0	0	0
Subtotal	1084.1	200.0	7450.0	7450.0
Purchases				
Alcan[6]	140.0	140	1225	1225
Established IPP Contracts	262.6	200	1700	1700
Non-Firm[7]	0	0	2200	2200
Subtotal	402.6	340.0	5125.0	5125.0
TOTAL	10818.3	9873.0	59905.0	56745.0

3 Hydroelectric totals include increases due to Resource Smart Programs where appropriate.
4 The others are Aberfeldie, Ash, Buntzen, Clayton Falls, Clowhom, Elko, Falls River, Ladore, La Joie, Puntledge, Seton, Shuswap, Spillamacheen, Stave Falls, Strathcona, Wahleach, Walter Hardman and Whatshan.
5 Burrard capacity includes increases due to the Burrard Upgrade project on Units 4 & 5 and the energy capability assumes an 85% annual capacity factor.
6 Expected purchase from Alcan, subject to the current contract negotiations.
7 Expected contribution from various non-firm resources including secondary hydroelectric and purchases from neighbouring utilities.

Figure 3.2

Existing Major Electrical System

3. 4 The Need For New Resources

3.4.1 Overall Energy and Capacity Needs

From the 20-Year Probable Demand Forecast and the energy and capacity available from the existing system the demand-supply outlook can be determined. Figure 3.3 shows the current Probable Demand Forecast for capacity, along with the capacity of the existing system and firm purchases.

Figure 3.4 shows the current Probable Demand Forecast for energy, along with the firm capability of the existing system. Figure 3.4 indicates that energy demand could exceed existing firm supply by about 1998; however, the contributions of secondary energy from the existing hydroelectric system or other non-firm sources are not shown. Secondary energy and energy from other non-firm resources could postpone the need for additional energy resources. The uncertainty associated with demand and the expected availability of non-firm and secondary energy resources in the short term indicates that additional resources are needed by 2001/2002 to ensure reliability requirements are met.

3.4.2 Energy and Capacity Needs By Region

The demand for electricity and the sources of supply both have a strong regional component. It is therefore important to consider not only the overall level of demand and sources of supply, but also the regions where they are located. Approximately 70 percent of current demand occurs in the Lower Mainland and Vancouver Island, while most of the generation is located in the north and south interior regions of the province.

This imbalance of supply and demand between regions is shown in Figure 3.5. As the demand and supply patterns change, the transmission system will need to be reinforced accordingly. Generally, the greater the imbalance between regions of supply and demand, the greater the need for reinforcement. The current outlook on transmission constraints is presented below.

3.4.3 Transmission Considerations

The key consideration in transmission planning is to maintain system reliability and quality of power supply. Figure 3.2 showed BC Hydro's major electrical transmission facilities. The development of this transmission system has been shaped by the significant imbalance in installed generation supply and electrical demand between regions, as mentioned in the previous section.

The need for future reinforcements of the transmission system and the nature of these reinforcements will be influenced by:

- the location and size of new generation resources;
- the possible electricity delivery and point of return of the Canadian Entitlement to the Columbia River Treaty downstream benefits;
- coordination and purchase agreements with other electricity producers;
- regional changes in electricity demands;
- third-party demand for transmission access;
- firm exports; and
- planning criteria.[8]

All of these factors affect the power transfer requirements of the system. Currently the power transfer capability of the major transmission system is limited by three principal factors: electro-mechanical stability; voltage stability; and the thermal rating of the transmission equipment. Different parts of the system are constrained by different limits. For example, the system from Kelly Lake and Nicola substations into the Lower Mainland is constrained by voltage stability in the near term and thermal limits in the long term. The purpose of transmission rein-

8 The electrical system is planned and designed to meet certain standards of performance under a variety of contingencies,such as loss of generation,a transmission line outage or other major equipment failures.

Figure 3.3:

1995 Capacity Demand-Supply Outlook

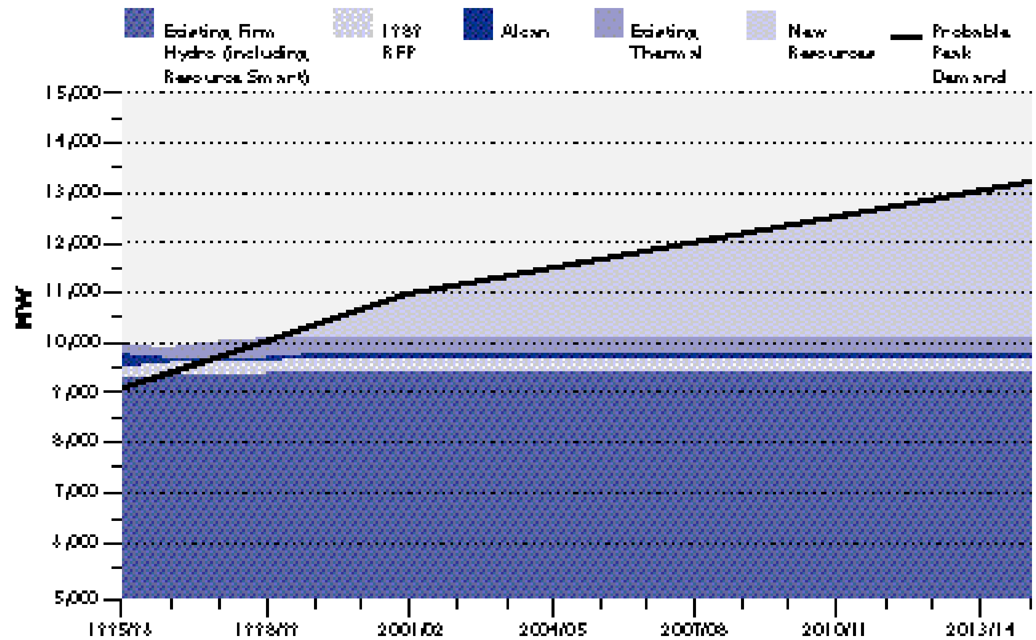
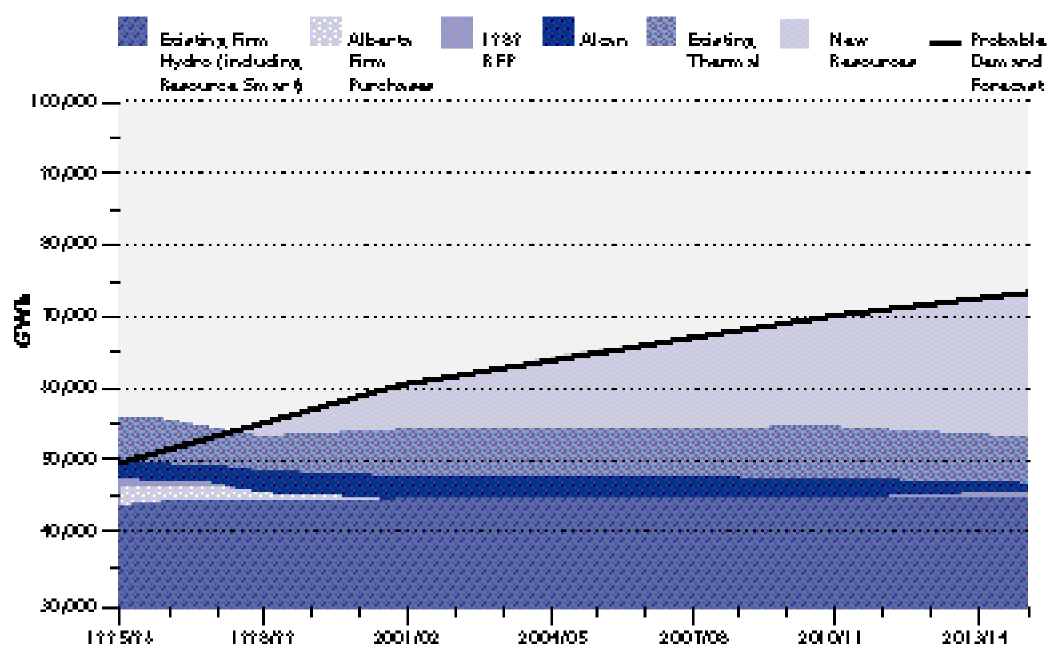


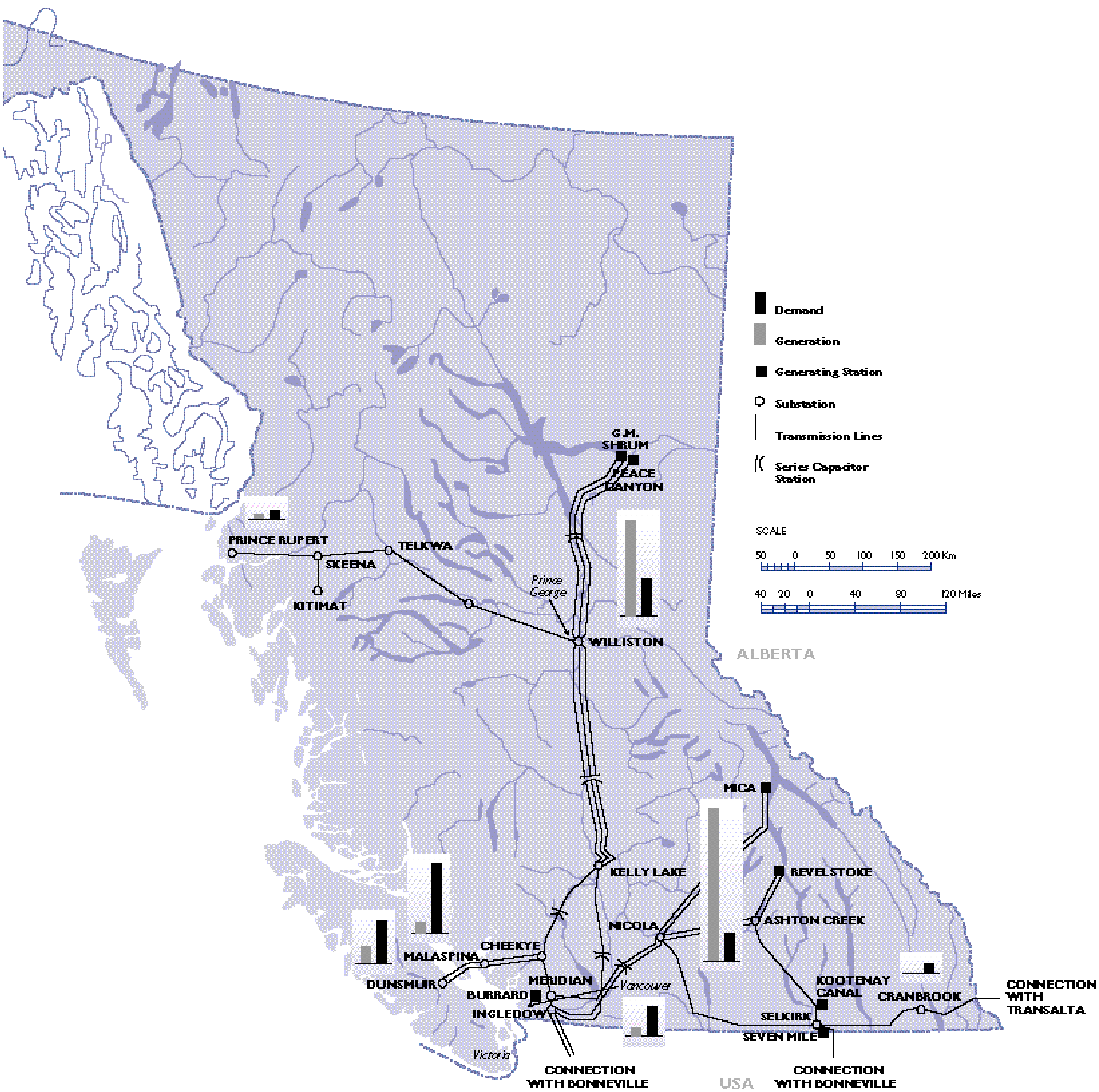
Figure 3.4:

1995 Energy Demand-Supply Outlook



Figur e 3.5:

Cur rent Regional Generation – Demand Imbalance



forcements is to overcome these limitations before they become critical constraints on system operations.

- There are two major “hot spots” (bottlenecks) developing in BC Hydro’s bulk transmission system which need to be reinforced to maintain system reliability. These are the interior to Lower Mainland and the Lower Mainland to Vancouver Island transmission interconnections.
- The lead time for building a new 500 kV transmission line is now 9 to 12 years under the existing regulatory process (much longer than that for new generation resources). Furthermore, land development in suitable transmission corridors may foreclose transmission line options (and consequently the development of some low-cost remote generation) unless rights-of-way can be secured and the lead time shortened. Long lead times for new transmission lines also reduce the flexibility to respond to variances in generation resource plans and load growth.
- The need to reinforce the transmission system from the Lower Mainland to Vancouver Island is dictated primarily by the aging of the existing High Voltage Direct Current (HVDC) terminal equipment and the HVDC and 138 kV tie submarine cables. These cables are due to be retired beginning in the year 2000. It is therefore important that either the Lower Mainland to Vancouver Island transmission system be reinforced or that generation be added on the Island.
- The need for reinforcing the interior to Lower Mainland transmission lines is driven by the strong growth in demand in the Lower Mainland and Vancouver Island and by the development of new remote generation in the interior. This growth has served to push these lines toward their stability limits.

Series capacitor banks are a cost-effective method of increasing the transfer capability of the transmission system. They increase the voltage and electro-mechanical stability limits of the system and allow the loading on the existing transmission lines to approach their thermal limits. In the short term, new series and shunt capacitor banks are required on the interior to Lower Mainland system, as well as the upgrading of existing series capacitor stations. In the longer term, additional 500 kV lines may be needed when the thermal limits of the existing lines become constrained, if generation continues to be added or increased in the interior and the load continues to grow primarily in the Lower Mainland and on Vancouver Island. Chapter 5 will discuss the transmission options in more detail. Chapter 8 will detail the recommended options to be pursued over the next four years.

SERIES CAPACITORS (SERIES COMPENSATION):

A group of capacitors that are connected to a transmission line in a series. These capacitors reduce the impedance of transmission lines and increase transmission capacity.

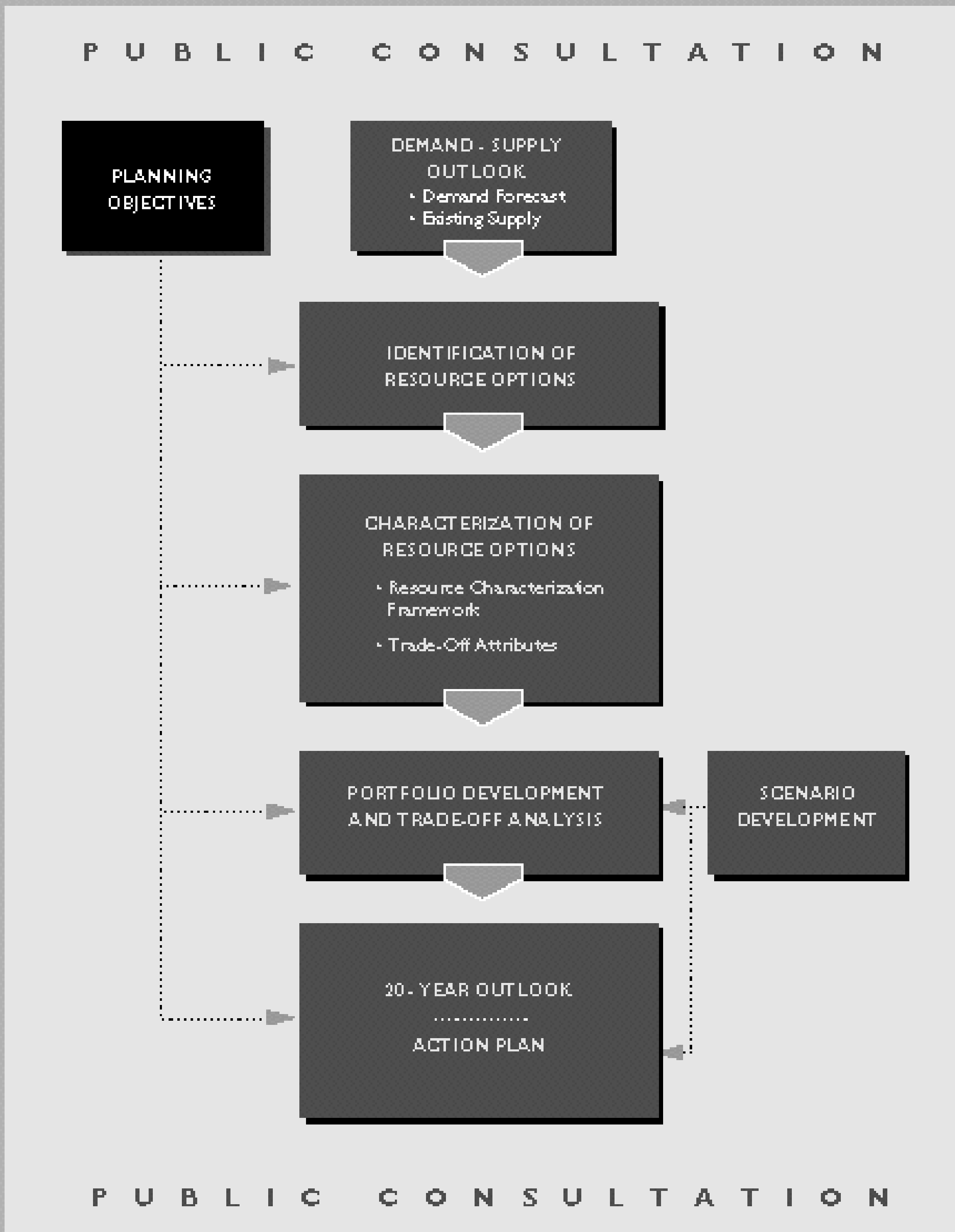
SHUNT CAPACITORS (SHUNT COMPENSATION):

Capacitors connected between line conductors or station bus and the ground to help raise system voltages and consequently increase the transmission capacity of the system.

3.5 Summary

The demand-supply outlook shows that BC Hydro requires additional resources to serve a forecasted increase in demand of 25,000 GWh per year of energy and 4,100 MW of capacity by 2014/15. Recognizing the capability of the existing electric system, this translates into a requirement for new resources of 3,700 MW. The need for energy may be partially met with the use of secondary energy. The location of generation and demand on the system, as well as aging equipment nearing the end of its useful life, will continue to drive transmission system reinforcement requirements.

CHAPTER 4
PLANNING OBJECTIVES



4 PLANNING OBJECTIVES

4.1 Introduction

The planning objectives provided guidelines for the planning process and the evaluation and selection of resource options. The objectives were translated into measurable attributes that were used to characterize and compare resource options. The objectives were carried through to the selection of the final mix of resources in the 20-Year Outlook and Four-Year Action Plan.

4.2 Developing the Planning Objectives

The objectives for the 1995 Electricity Plan were derived from three main sources: BC Hydro corporate policies, input from the Consultative Committee; and input from senior managers from various BC Hydro business units.

Corporate policies, particularly *The Way Ahead* and the *Resource Acquisition Policy*, provided broad strategic direction. In particular, *The Way Ahead* identified five strategic objectives, while the *Resource Acquisition Policy* identified financial, technical, environmental, social/community and economic development factors that were to be considered in the evaluation of resource options.

STRATEGIC OBJECTIVES FROM THE WAY AHEAD:

- *To be a leader in the economic and social development of British Columbia.*
- *To be a leader in stewardship of the natural environment.*
- *To be the most efficient utility in North America.*
- *To be a superior customer service company.*
- *To be the most progressive employer in British Columbia.*

The Consultative Committee members provided input on society's values while BC Hydro senior managers provided input on important corporate factors, such as marketplace considerations.

The process to develop the objectives for this Plan began by interviewing members of the Consultative Committee and BC Hydro senior managers as well as reviewing BC Hydro corporate policies. This led to an initial set of objectives in February 1995. The Consultative Committee recommended a final set of objectives to BC Hydro in March. The recommended objectives were adopted by BC Hydro with minor changes, as noted in the following discussion. McDaniels Research Ltd. assisted in the development of these objectives and this report is contained in Appendix C.

4.3 The 1995 Integrated Electricity Plan Objectives

The 1995 Integrated Electricity Plan objectives include one overall objective and nine specific objectives, some of which have a number of sub-objectives[1]. The final set of objectives is presented in Table 4.1.; the differences between the final set of objectives adopted by BC Hydro and the Consultative Committee's recommendations are indicated in boxes labeled as 'CC'.

4.4 Differences Between the Adopted Objectives and Consultative Committee Recommendations

The difference in the objectives are outlined in the following discussion.

SUB-OBJECTIVE 1.1

The Consultative Committee recommended:
"Minimize financial costs of meeting electric service needs."

1 The Consultative Committee also developed an objective specifically for itself but this is not included as part of the Plan's set of objectives. The Consultative Committee's overall objective was, "To provide recommendations regarding the best electrical services for current and future generations of British Columbians by the most appropriate means."

Table 4.1:

The 1995 Electricity Plan Objectives

OVERALL ELECTRICITY PLAN OBJECTIVE:
To provide the best electrical services for current and future generations of British Columbians by the most appropriate means.

OBJECTIVES:

1. Minimize costs of electrical services to customers.

	1.1	Minimize costs of meeting electric service needs.
CC	*1.1*	*Minimize financial costs of meeting electric service needs.*
	1.2	Minimize adverse impacts of required capital expenditures by customers.
	1.3	Avoid rate shock.
	1.4	Minimize costs to other government agencies.

2. Provide quality customer service that meets customer needs and expectations...

CC	*2.*	*Provide high quality customer service.*
	2.1	Meet electric service needs: • Secure energy supply. • Secure capacity supply.
	2.2	Provide reliable service: • Minimize service outages. • Minimize service restoration time.
	2.3	Provide high power quality: • Minimize voltage changes. • Minimize frequency changes.

3. Provide flexible service to adapt to changes.

3.1	Changing demands.
3.2	Changing technologies.
3.3	Changing regulations.
3.4	Changing values.

4. Provide choice to customers regarding electricity services.

5. Minimize adverse and promote positive environmental impacts.

5.1	On land resources, including: • flora, fauna, soils, ecosystems and biodiversity.
5.2	On water resources, including: • flora, fauna, ecosystems and biodiversity.
5.3	On air resources, including: • visibility.
5.4	On local climate.
5.5	On global climate, • from greenhouse gas contributions
5.6	On wilderness preservation.
5.7	On natural aesthetics.

6. Minimize health and safety impacts.

6.1	Early deaths.
6.2	Sicknesses.
6.3	Injuries.

7. Optimize socio-economic impacts.

	7.1	Minimize adverse and promote positive impacts on individuals: • Minimize displacement of residents. • Minimize aesthetic impacts of facilities. • Minimize personal disruption.
	7.2	Minimize adverse and promote positive effects on communities: • On the social environment. • On community social infrastructure. • On drinking water quality. • On man-made structures.
	7.3	Minimize adverse and promote positive impacts on aboriginal peoples.
CC	*8.7*	*Ensure fair and equitable treatment of aboriginal peoples*
	7.4	Shape urban growth to foster: • Compact communities. • Complete communities.
	7.5	Support regional economic development: • Foster sustainable development. • Foster community viability.
	7.6	Minimize adverse and promote positive impacts on the resource-based sectors of the economy, including: • Forestry, tourism, trapping, fisheries, mining, guide outfitting, agriculture and wildcrafting.
	7.7	Keep industry and business electricity costs competitive with other jurisdictions.
	7.8	Minimize adverse and promote positive impacts on recreational opportunities, including: • Sport fisheries, wildlife viewing & photography, wilderness appreciation, hiking, camping and boating.

8. Ensure fair and equitable treatment.

8.1	Among customers bearing costs of new programs.
8.2	Among regions regarding transfer of wealth.
8.3	Among current and future generations regarding resource availability.
8.4	Among nations regarding global energy consumption.
8.5	among firms and individuals providing electrical services.
8.6	Regarding evaluation of electrical service options.

9. Promote implementation of appropriate new and existing technology.

9.1	For generation.
9.2	For transmission.
9.3	Other aspects of electrical services.

BC Hydro adopted:

"Minimize costs of meeting electric service needs."

The difference centered on the word "financial". The intent of the Consultative Committee was to specify that the dollar costs of electrical service should be minimized. BC Hydro felt the word 'financial'had broader connotations than just dollar costs (e.g., rate impacts, cost of borrowing).

OBJECTIVE 2

The Consultative Committee recommended:

"Provide high quality customer service."

BC Hydro adopted:

"Provide quality customer service that meets customer needs and expectations."

The difference is as a result of the changing nature of the electric utility industry and different levels of customer service. 'High quality'may mean different things to different customers. For example, customers may be willing to accept a lower level of service in exchange for lower rates and still feel they are receiving quality service. BC Hydro therefore thought it more appropriate to express this objective in terms of customer needs and expectations. Quality can be defined as conforming to customer needs which may not always mean high quality.

SUB-OBJECTIVE 8.7

The Consultative Committee recommended that the objective concerning aboriginal peoples be included under Objective 8 as:

"Ensure fair and equitable treatment of aboriginal peoples."

BC Hydro preferred to address this issue under Objective 7 – "Optimize socio-economic impacts", as:

"Minimize adverse and promote positive impacts on aboriginal peoples."

BC Hydro's commitment to ensuring 'fair and equitable treatment'of aboriginal peoples will be realized by minimizing adverse and promoting positive socio-economic impacts. Aboriginal concerns with respect to the environment will be reflected, along with the concerns of other stakeholders, under Objective 5 – "Minimize adverse and promote positive environmental impacts".

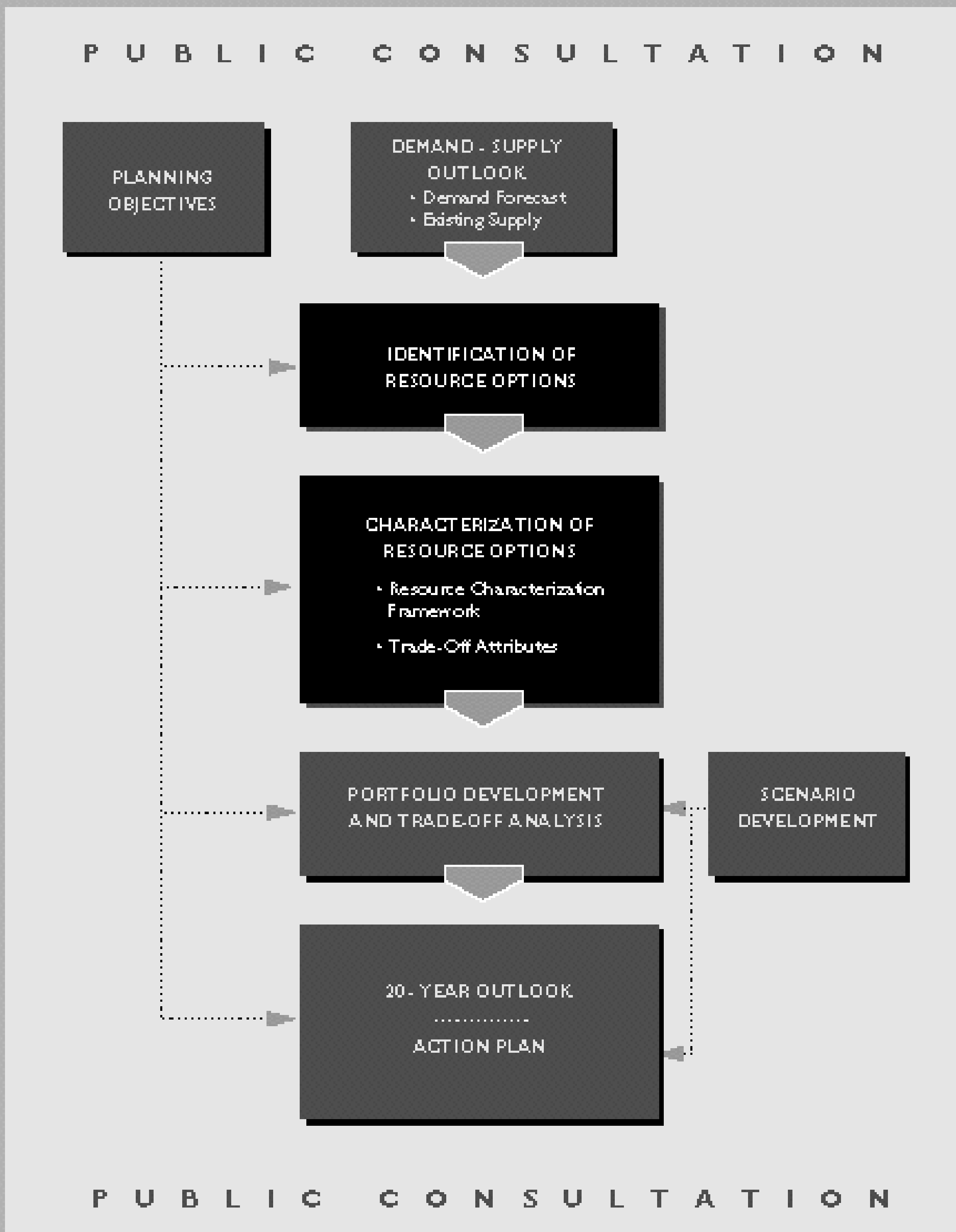
4.5 Linking Objectives with Attributes

From the nine major objectives and sub-objectives shown in Table 4.1, approximately 55 attributes were developed to qualitatively or quantitatively characterize individual resource options. A further 12 trade-off attributes were developed to evaluate portfolios of resources (Chapter 5). For example, the sub-objective "Minimizing impacts on global climate" led to the trade-off attribute used in the portfolio evaluations which measured greenhouse gas emissions in tonnes of carbon dioxide equivalents.

4.6 Summary

The objectives developed in this process address the planning values important to both BC Hydro and stakeholders, and provide a foundation for the planning process and this Plan. Subsequent chapters will show how these objectives were used to develop attributes, describe resource options and assist in identifying the trade-offs to be made in developing a preferred portfolio of resources. In Chapter 7 the objectives are revisited to see how well they were addressed by the selected portfolio. As the next step however, the following chapter will draw upon these objectives to develop attributes and characterize resource options.

CHAPTER 5
IDENTIFICATION AND CHARACTERIZATION OF RESOURCE OPTIONS



5 IDENTIFICATION AND CHARACTERIZATION OF RESOURCE OPTIONS

5.1 Introduction

This chapter expands on and integrates two previous chapters: Demand-Supply Outlook (Chapter 3) and Planning Objectives (Chapter 4). Figure 5.1 provides an overview of the linkages.

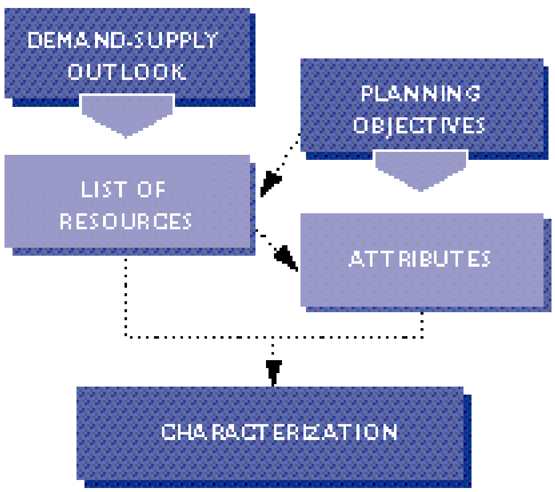


Figure 5.1:

Steps in the Identification and Characterization of Resource Options

The demand-supply outlook outlined the problem statement for the Plan by describing the range of forecast demands BC Hydro expects to serve as well as the capability of existing facilities. The difference is the amount of electricity BC Hydro may require in the future to meet customers' needs.

In Section 5.2, resources[1] are identified that could be used to meet customers' needs. Supply options include alternative technologies, hydroelectric, thermal, purchases and transmission. Demand options include community energy planning, demand-side management programs and rate design changes to influence demand.

The planning objectives drove the development of criteria for evaluation of resource options. These criteria are referred to as attributes and are defined more specifically as financial, technical, environmental, social/community and economic development measures. The list of potential resources and knowledge about the type of information available for these resources were also considered in developing the attributes.

The list of possible resources and the attributes are combined in resource characterization. Each possible resource is described according to the attributes to indicate its strengths and weaknesses and hence its contribution to the objectives of the Plan.

The Consultative Committee participated in developing both the list of resources and the attributes. BC Hydro conducted the resource characterization and provided members of the Consultative Committee an opportunity to comment.

The purpose of this chapter is to identify and describe the resource options considered in the Plan. Section 5.2 provides the list of resource options which reflects over 100 individual projects and programs available to be chosen in building portfolios (Chapter 6). Discussion is at the resource type level (e.g., natural gas-fired thermal or demand-side management) rather than individual project or program level (e.g., Burrard repowering, BC 21 Power Smart), so that a general summary of each resource type can be presented.

Section 5.3 provides a discussion of attribute development while Section 5.4 provides a description of each resource type and applies the attributes to characterize the resources. Resource Summaries (Appendix E) provide information on individual projects and programs.

5.2 List of Resource Options

BC Hydro and the Consultative Committee reviewed the resource options identified in the *1994 Electricity Plan*. Taking into consideration the demand-supply outlook and

1 Resources are investments in facilities or expenditures in programs or purchases to meet electricity needs by providing new supply or changing the demand for electricity.

the planning objectives, resources were added to, and deleted from[2] the inventory as described in the following sections. Although efforts were made to reduce the number of resources, many resources were included to allow the analysis discussed in Chapter 6 to demonstrate the performance of the resources. Table 5.1 is a summary list of resource options. Reasons why resource types were or were not included in the list of options is provided below.

In late 1994 an economic opportunity was identified for the private sector to provide electricity to BC Hydro at prices which were expected to reduce BC Hydro's overall cost of electricity. In December 1994, an all-source Request for Proposals to supply BC Hydro with electricity was issued.

On 15 March 1995, 48 proposals were received, including 13 natural gas, 13 wood residue, 1 geothermal, 16 hydroelectric and 5 demand-side management.

Project information from these responses was grouped by resource type (e.g., hydroelectric) and included in the inventory.

5.2.1 Generation

Four resource types are discussed in this subsection. Many of the resources could be implemented as distributed generation by BC Hydro, customers or third parties (e.g., independent power producers).

DISTRIBUTED GENERATION:

Electricity generation, usually on a small scale, which is located throughout the electrical distribution system, usually closer to load centres or customers.

Table 5.1:

Summary List of Resource Options

GENERATION	DEMAND-SIDE	TRANSMISSION
Alternative Technologies -free stream tidal -fuel cells -solar -wave -wind	Community Energy Planning	Transmission Lines: -overhead circuits -cable circuits -new facilities -upgrades to existing facilities
Hydroelectric -resource smart -augmented generation -new facilities -capacity	Demand-Side Management -residential -commercial -industrial	Stations: -new switching stations -new and upgrades to existing reactive power compensation facilities
Thermal -coal -geothermal -natural gas -wood residue	Rates -residential -general -transmission	Distribution Automation: -control of feeder shunt capacitors -control of transformer voltage-regulating tap changes and feeder voltage regulators
Purchases -Imports (Alberta & U.S.) -Alcan -downstream benefits		

2 One member of the Consultative Committee was interested in all options being considered and stated that resources should not be removed from the list of options. BCHydro decided to screen the resource options, reducing the number of options to a more manageable level.

ALTERNATIVETECHNOLOGIES

Alternative technologies include freestream tidal, fuel cells, solar[3], wave and wind as they are developing technologies[4] with potential in British Columbia. Conventional tidal was not included because of high cost and potential negative aquatic impacts.

HYDROELECTRIC

Hydroelectric resources were divided into resource smart, augmented generation (at existing facilities), new facilities and capacity additions.

Resource Smart

Resource Smart is a program of cost-effective efficiency and operational improvements at existing facilities.

Augmented Generation

Augmented generation projects are additions or modifications to existing facilities to increase energy produced and/or provide capacity. They include Seven Mile 4, Stave Falls Powerplant Replacement, Duncan and others.

As discussed in Section 1.3.8, the Columbia Power Corporation has acquired the rights to expand the Brilliant and Waneta projects and has filed an application for approval to install power facilities at the Keenleyside Dam. Although they are not BC Hydro resources, electricity from these projects could be made available for purchase by BC Hydro in the future. Therefore, these augmented generation resources at existing facilities were included.

New Facilities

Large hydroelectric projects requiring new dams on ‘developed’rivers typically have moderate to high costs. Peace Site C was included in the list of resources as it is the lowest cost large hydroelectric project requiring a new dam on a developed river. Large hydroelectric projects requiring new dams on ‘undeveloped’rivers were not included due to high cost and potential negative environmental and social impacts. In addition, the long lead times and large increments of energy and capacity associated with this type of resource may require the outlay of significant capital long before the need for new electricity supply.

PUMPED STORAGE:

The use of electricity generated during off-peak hours to pump water from a lower elevation reservoir to a higher reservoir. The stored water is then released during peak demand periods and used to turn a reversible pump/turbine generator before returning to the lower reservoir.

Capacity Additions

Capacity addition opportunities at Revelstoke and Mica are included as was pumped storage.

THERMAL

Natural gas, wood residue, geothermal and coal-fired thermal were included as they are all relatively cost-effective proven technologies. Oil-fired thermal was not included due to the availability, cost and environmental advantages of natural gas.

Landfill and sewage gas-fired plants were not included due to their small potential and relatively high cost. Municipal solid waste and peat-fired generation were also excluded due to potential high cost and potential negative environmental impacts.

Nuclear was not considered for inclusion in the list of resources, because of high cost, potential environmental and social/community impacts and legislation restricting siting.

PURCHASES

Imports from Alberta and the U.S. are viable and cost-effective resources. Purchases of electricity from Alcan and the Columbia River Treaty downstream benefits are also included, (see Section 5.4.6 and Section 7.3).

3 Solar photovoltaics were included instead of solar thermal electricity generation.Solar thermal water and space heating are consumer fuel choices.
4 Costs are declining and these resources may be cost-effective for grid application in British Columbia in the future.

5.2.2 Demand-side

COMMUNITY ENERGY PLANNING

Community energy planning is a process involving municipal governments, planners, business and residents to promote energy aware community and land planning. It was included on the basis of reasonable cost and environmental implications.

DEMAND-SIDE MANAGEMENT

The *Draft 1995 Demand-Side Management Plan* is made up of BC Hydro's residential, commercial and industrial programs which modify customers' demand for electricity (i.e., Power Smart). The demand-side management potential identified in the Conservation Potential Review (CPR) Phase II Achievable was also included.

RATES

Intra-class rate options (rate changes such as seasonal, regional, time of use) that influence demand were included. Rate options involve changing the pricing structure to influence the timing of electricity consumption. These programs could affect the magni-tude of peak demand and shape of the demand profile. They also can provide customers more choices for their supply of electricity.

5.2.3 Transmission

Transmission options were included to ensure they are characterized in a manner that is consistent with generation and demand-side resources. New and upgraded transmission lines as well as new and upgraded stations that address the potential system power transfer constraints from the interior to the Lower Mainland and from the Lower Mainland to Vancouver Island were included.

Although not discussed in detail with the Consultative Committee, distribution automation at substations to control voltage and reactive power[5] on the distribution system was also included as it is a potential, cost-effective energy and capacity savings measure.

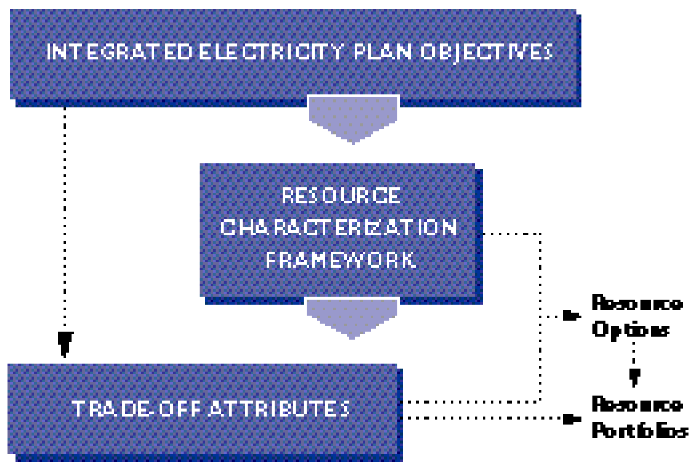
Transmission options to address other power transfer issues were not included in the inventory nor were options to address sub-transmission (below 230 kV) transfer constraints, as they are beyond the scope of this Plan.

5.3 Attributes

Evaluation and selection of resource options to meet future demand requires the comparison of options and how each contributes to the objectives of the Plan. To undertake a consistent comparison, each option was described using a common set of criteria or attributes. Similarly, different combinations or portfolios of resource options were compared using a consistent set of attributes. In this section, the structure of the attributes and the process for their development is explained (Section 5.3.1) and each attribute defined (Section 5.3.2).

5 Reactive power is the component of power which gets interchanged between the source and reactive elements to establish magnetic and electrostatic field.The energy associated with this component is zero. Major sources of reactive power are series and shunt capacitors.The unit of reactive power is VAR (volt-ampere reactive). Reactive power is required for motor drives,fluorescent lighting and other end uses.

Figure 5.2:
Structure of Attributes



5.3.1 Structure of Attributes

Attributes used in the analysis of resource options and portfolios were driven by the planning objectives (Chapter 4). A detailed set of attributes – the Resource Characterization Framework – was developed to guide the evaluation of individual resource options. A more focused set of criteria – trade-off attributes – was identified to describe specific aspects of individual resource options and to evaluate resource portfolios. This structure is summarized in Figure 5.2.

RESOURCE CHARACTERIZATION FRAMEWORK

The Resource Characterization Framework (RCF) provides a comprehensive set of attributes by which resource options may be characterized and compared. The RCF is structured around five accounts: financial, technical, environmental, social/community and economic development. These accounts reflect the main themes in the Plan's objectives, as well as the categories identified in the *Guidelines for Multiple Account Evaluation* published by the Crown Corporations Secretariat (1993). The RCF contains about 55 detailed attributes to support a framework for evaluation that is comprehensive for all resource types and planning objectives. The attributes are disaggregated to avoid value judgments regarding combined measures.[6] Attribute measures may be monetary, quantitative or qualitative.

The RCF was based on a draft list of attributes compiled from integrated resource plans and policy documents. Workshops and meetings with technical experts (BC Hydro and outside consultants) were then held to refine the draft list and to determine appropriate measures for each attribute. Finally, the RCF was reviewed by the Consultative Committee and comments and suggestions were integrated into the Framework.

The RCF builds on BC Hydro's *Resource Acquisition Policy*, a document which sets out the principles of multi-criteria evaluation of resource options. The RCF provides more specific characterization of land and water impacts

6 For example, the RCF separates out attributes related to different species (e.g., fish, wildlife, vegetation). Combining the species into a single attribute (measure) embeds judgments concerning the relative value of one versus another species. Although trade-off attributes make such judgments (in consultation with stakeholders), the RCF is intended to be value-free.

Table 5.2:
1995 Integrated Electricity Plan Trade-Off Attributes

FINANCIAL ACCOUNT	TECHNICAL ACCOUNT	ENVIRON-MENTAL ACCOUNT	SOCIAL/ COMMUNITY ACCOUNT	ECONOMIC DEVELOPMENT ACCOUNT
Present value of system costs	Diversity index	Species persistence	Land use	Employment
Rate impact		Terrestrial ecosystems		
		Population-weighted local air emissions		
		Greenhouse gas emissions		
		Particulate emissions		
		Upstream air emissions		
		Electric and magnetic fields (EMF)		

as well as alternative values for some monetized attributes (e.g., air emissions). It also offers alternative measures of financial and technical attributes, to reflect the specific objectives of the 1995 Plan.

The RCF guided the broader review of resource options listed in the resource inventory and provided a basis for the identification of the trade-off attributes discussed below. In addition, the RCF offers a basis on which new information may be collected in a consistent manner, thereby supporting future resource planning. However, the RCF does not substitute for detailed financial and technical analyses or environmental impact assessments, all of which are necessary for project-level design and licencing.

The complete RCF is included in Appendix E.

TRADE-OFF ATTRIBUTES

Trade-off attributes are comprised of highlights and combinations of the attributes in the RCF. They provide a smaller, more manageable set of criteria by which to compare resource portfolios. For example, species persistence is a combination of fish and aquatic resources, wildlife resources and terrestrial resources and habitat. As such, trade-off attributes reflect broad strategic and planning level issues.

The list of trade-off attributes was developed, as much as possible, from the RCF attributes. This list was further refined to address BC Hydro corporate and Consultative Committee interests, recognizing data availability could be limited for some attributes. The 12 trade-off attributes used in the Plan span the five accounts identified in the RCF and Crown Corporations Secretariat *Guidelines for Multiple Account Evaluation,* and are shown in Table 5.2. Each trade-off attribute is explained below.

5.3.2 Financial Trade-Off Attributes

ATTRIBUTE 1: PRESENT VALUE OF SYSTEM COSTS

Present value of system costs measures the cost of meeting the Probable Demand Forecast, reliability criteria and reserve requirements for the system as described in Chapter 3. The present value (PV) of system costs is a measure of economic efficiency. It measures the total cost of an initiative or project to the people of the province. It

PRESENT VALUE OF SYSTEM COSTS

The present value of costs associated with a portfolio of resources which meets the 20-year forecast demand, where costs include:

- *capital, operating, maintenance and fuel costs for electricity generation and transmission;*
- *utility and net customer costs to implement and monitor demand-side management programs;*
- *corporate overheads and interest during construction for capital projects and demand-side management programs;*
- *contracted purchase prices less transfer payments for electricity acquired from independent power producers; and*
- *purchase prices for imports.*

Costs are expressed in constant (uninflated) 1994 dollars, discounted at eight percent.[7]

includes operating and maintenance costs and capital costs. However, system cost does not include transfers (e.g., taxes) from BC Hydro to the federal, provincial or municipal governments because they do not represent costs to the people of British Columbia as a whole.[8]

For demand-side management programs, the system cost attribute takes into account all costs of a program, be they costs to BC Hydro or the individual installing or adopting demand-side management measures. This is equivalent to a total resource cost. Where incentive payments are included as costs to the utility, they are also included as benefits to the customer. Therefore, as a transfer from one group (BC Hydro) to another (the customer), incentives sum to zero in the calculation of system costs.

The portfolio analysis used a detailed breakdown of costs (e.g., fixed and variable operating costs, fuel costs, capital costs). However, data in this form do not provide useful information by which individual resource options (or resource types) may be compared. Since electricity projects can be expressed in many different combinations of energy output, capital cost, location, start date and term, the basic cost data shown on the supply curves in this chapter (and in the Resource Summaries in Appendix E) have been expressed in terms of levelized unit economic cost of firm energy delivered to the Lower Mainland.

Levelizing is a method of obtaining an average unit cost that incorporates the time value of the resource. One method of levelizing is to convert both total cost and total electricity production streams into values at a single point in time (i.e., present value) and divide the present value of the costs by the present value of electricity production.

Economic costs, sometimes referred to as corporate costs less transfers, include corporate capital and operating costs, purchase price for imports and private power projects and credits/charges for capacity, storage and transmission but exclude transfers and monetized air emissions. While not an exact match to the present value of system costs used for comparison of portfolios, levelized unit economic cost is an appropriate proxy for comparison of individual resource options.

ATTRIBUTE 2: RATE IMPACT

The rate impact attribute measures the change in rates (tariff) which would occur as a result of different combinations of resources. The benchmark for comparing changes in rate impact is the levelized tariff of the reference portfolio (see chapter 6).

Before calculating the percent change relative to the reference portfolio, the levelized tariff was first calculated by discounting the total projected BC Hydro revenues in each year, summing them and dividing the resulting present value by the discounted energy sales over the period. The revenues are calculated as electricity sales in each customer class multiplied by the respective rate for each customer class.

7 The 8 percent discount rate is set by the Provincial Government. However, sensitivity tests around this rate were undertaken and are discussed in Appendix F.
8 For the 1995 Integrated Electricity Plan, transfer payments are as defined in the June 1994 *Resource Acquisition Policy* and include: water rental fees paid on hydroelectric generation; provincial sales tax; corporate capital tax; municipal, property and school taxes; grants in lieu of taxes as established by the Province; and motor fuel tax.

RATE IMPACT

The percent change in levelized tariff relative to a reference portfolio, where:

- *the levelized tariff is the levelized unit energy price (¢/kWh) averaged across all customer classes (e.g.; residential, general and transmission): and*
- *the reference portfolio is a specific combination of resources that provides a benchmark for comparison of alternative portfolios in the trade-off analysis (see Chapter 6).*

This calculation is similar in form to the calculation of levelized unit economic cost of firm energy; however, instead of comparing the cost of projects of different sizes and with different cash flows, levelized tariff compares the revenue impacts of a group of projects. The calculation levelizes the year-to-year rate changes, allowing them to be expressed as a single rate, from which the comparison with the reference portfolio can be made in terms of a percent change.[9]

The main factors which influence the value of the levelized tariff include:

- the timing and amount of capital and operating expenditures borne by the utility (including transfers) associated with a particular resource portfolio;
- the in-service dates of energy and capacity additions to the integrated system;
- the timing and utility cost of demand-side management programs, and their related energy and capacity savings;
- decisions of the BCUC (e.g., approval of the rates BC Hydro is allowed to charge for electricity services and determination of the rate-of-return on equity to be paid by BC Hydro to the Province); and
- elasticity assumptions, i.e., the change in electricity consumption patterns due to changes in rates.

5.3.3 Technical Trade-Off Attributes

ATTRIBUTE 3: DIVERSITY INDEX

A single technical attribute, namely diversity index, was used in the trade-off analysis to measure the diversity of the resource mix in a portfolio. The attribute has two components, number and type of resource additions; the index is simply the product of these.

The ‘number’ component includes one point for each resource addition regardless of size and one point for each 50 MW increment of demand-side management. The ‘type’ includes one point for each type of resource, such as BC Hydro hydroelectric facilities, private power hydroelectric developments, wind farms or industrial demand-side management. A total of 21 resource types were identified (see Table 5.3).

The diversity index improves as more resources and different resource types are added to the BC Hydro system, on the premise that increased diversity provides the means for better risk management. That is not to say that a number of smaller plants is more reliable than a single large plant. Rather, a more diverse system could provide increased flexibility to respond to changes in fuel supply, environmental regulation, technology and could prove to be less vulnerable to outages or catastrophic events which may severely impact one type of resource.

The question of whether or not to define this attribute as an indicator of regional equity[10] fueled discussions span-

DIVERSITY INDEX

N x M, where:

- *N is the number of new resource additions in a portfolio; and*
- *M is the number of different resource types included in a portfolio.*

9 Although the trade-off attribute was defined as the percent change in levelized tariff relative to the reference porfolio, the levelized rate in mills per kilowatt hour was also provided as an information item for portfolios examined in the trade-off analysis.(Mills equals one-tenth of a cent.)
10 Regional equity refers to the distribution of “benefits” and “costs” amongst the regions of British Columbia so that the regions who pay also receive benefits.The terms benefits and costs have broad definitions.They may be actual dollar payments,changes in employment,natural resources,environment impacts or other services.

Table 5.3:

Resource Types Considered in Diversity Index

ALTERNATIVE TECHNOLOGIES	HYDRO-ELECTRIC	THERMAL	PURCHASES	DEMAND-SIDE MANAGEMENT
Freestream tidal	BC Hydro	BC Hydro natural gas	Alberta Coal imports	Residential
Fuel Cells	Private Sector	Private Sector natural gas	Alberta Gas imports	Commercial
Solar photovoltaics		Natural gas cogeneration	U.S.imports	Industrial
Wave		Wood residue	Downstream Benefits	
Wind		Wood residue cogeneration		
		Coal		
		Geothermal		

ning several Consultative Committee meetings. Some members felt that in a more diverse system, generating plants were more likely to be located closer to the loads they served. Consequently, one region of the province would not bear the environmental and social costs associated with the construction and operation of generating stations while another received the electricity benefits. However, the Consultative Committee ultimately concluded it did not wish to tie the diversity index to geographic location, preferring to use this attribute as a technical measure related to risk management.

The Consultative Committee also discussed the definition of 'resource additions'. One member suggested, for example, that each windmill in a wind farm should constitute one resource addition. In consideration of this interest, BC Hydro used the relatively small development size of 20 MW to define a generic wind farm.

5.3.4 Environmental Trade-off Attributes

One of the concerns related to energy projects, as with most resource initiatives, is the impact on land, air and water resources. The RCF environmental account contains numerous criteria related to fish and aquatic resources, wildlife resources, terrestrial resources and habitat, air quality and materials management. These attributes were synthesized into seven trade-off attributes, as follows:

ATTRIBUTE 4: SPECIES PERSISTENCE

Species persistence captures the impact of a particular resource option on populations of fish, wildlife and vegetation. It measures the number of species that could be significantly affected by the project or development; that is, the number of species for which the viability of local populations could be at risk.

There was some interest among Consultative Committee members to incorporate a measure of abundance in the species attribute, not simply the identification of significant reductions in population. However, quantitative information on changes in abundance is not currently available for the range of resource options identified in

SPECIES PERSISTENCE

Number of species affected by the project, where:

- *'affected' is defined as the number of species for which a project is likely to cause a significant decrease in numbers relative to expected population in the local area;*
- *'species' includes plants and animals, both terrestrial and aquatic as well as waterfowl;*
- *species types are summed, thus implicitly assigned equal weight or importance to each species category;*
- *species includes red-listed and other (generally blue-listed and regionally significant) species. Red-listed species are those that are considered endangered or threatened; Blue-listed species are those that are considered vulnerable.[11]*
- *red-listed species are accorded a weight of 1; non-red-listed species are given a relative weight of 0.5 Although reviewed with the Consultative Committee, the relative weights of 1 and 0.5 are essentially arbitrary. However, as suggested in Section 5.3, the implications of different weights would be minor, as few species are affected by projects and most species identified are red-listed*

the inventory. Subsequent refinements may enable incorporation of abundance in the future.

ATTRIBUTE 5: TERRESTRIAL ECOSYSTEMS

The terrestrial ecosystems trade-off attribute captures potential loss of sensitive ecosystems such as old growth forests, native grasslands and wetlands.

Terrestrial ecosystems and species persistence serve as proxies for a more comprehensive indicator of biodiversity. Using the two separate attributes has disadvantages. First, species persistence does not fully capture changes in abundance except for significant decreases in numbers relative to the local population. Second, there may be some overlapping between species persistence and terrestrial ecosystems. Aquatic ecosystems are not specified because there is an even higher potential for overlap (and hence, double-counting) and because impacts on aquatic ecosystems may reflect changes in, rather than losses of, such environments. BC Hydro suggested that aquatic species would serve as a proxy at this time to capture the impacts associated with changes to aquatic ecosystems.

Although a comprehensive biodiversity index may mitigate some of these weaknesses, an appropriate indicator (and data to support an index) was not available for this Plan. Subsequent work could usefully focus on developing such an indicator and identifying project-specific information required to calculate it.

ATTRIBUTE 6: LOCAL AIR EMISSIONS

The RCF identifies a variety of emissions of concern to local air quality and its associated health impacts. These include:

- nitrogen oxides (NOx), a precursor to ozone which is a major component of urban smog and visibility. It is a contributor to acid deposition, with primary and secondary pollutant health impacts (and also accounts for volatile organic compounds);

TERRESTRIAL ECOSYSTEMS

Number of hectares lost within special zones where:

- *'special zones'are wetlands, native grasslands, old growth, alpine, flood plains, areas near to ecological reserves and pristine wilderness (including parks);*
- *'number of hectares lost' represents loss of the original ecosystem (i.e., disturbed); and*
- *'number of hectares' is identified separately for each type of special zone, then summed to derive a single value, thereby implicitly assigning equal weight or importance to each type of ecosystem affected.*

11 These definitions are from the BC Conservation Data Centre, Victoria, BC (March 1995).

LOCAL AIR EMISSIONS

Tonnes of population-weighted local air emissions where:

- *local air emissions include NOx, SOx, and PM*
- *tonnes of emissions are aggregated according to the following set of weights.*[1]

	Weight	RAP Value
NOx	1.00	$1,200/tonne
SOx	4.08	$4,900/tonne
PM	1.75	$2,100/tonne

1 Based on relative monetary values from the Resource Acquistion Policy.

- *Population weights are applied by multiplying emissions by population within 100 km radius of the project.*

Theoretical sample calculation:

- *Emissions: NOx = 100 tonnes; SOx = 0 tonnes; PM = 5 tonnes*
- *Population weight = 1 million (urban centre)*
- *Calculation: [100 (1) + 0 (4.08) + 5 (1.75)] x 1.0 million = 108.75 million weighted tonnes.*

- sulphur oxides (SOx)[12], associated with acid deposition and health impacts; and
- particulates (PM and PM-10), associated with visibility impairment and health (respiratory) impacts.

Emissions for all three pollutants are expressed in tonnes and aggregated based on relative impacts which in turn are based on monetary values stated in the 1994 *Resource Acquisition Policy*. As an indicator of health impacts, emissions are weighted by population within a 100 km radius of the project.[13]

New research suggest alternative values to the dollar values and relative weights specified in the *Resource Acquisition Policy*. A study commissioned by the Greater Vancouver Regional District for example[14] indicates that particulate matter and, more specifically, fine particulates (particles less than 10 microns, also known as PM-10) are significantly more harmful to human health than either NOx or SOx. The study also suggests that damage values are higher for all pollutants once fine particulates are taken into account[15]:

Alternative Monetized Values for Air Emissions

NOx	*$5300/tonne*
SOx	*$7500/tonne*
PM	*$20,500/tonne*

Air emissions were monetized using the *Resource Acquisition Policy* values and alternative values in a scenario analysis (Section 7.3.6).

ATTRIBUTE 7: PARTICULATEEMISSIONS

Part way through the portfolio analysis, concern was expressed by one member of the Consultative Committee that rural air quality was not adequately addressed. Specifically, the value of rural air quality was diminished by weighting local air emissions, measured as tonnes emitted, by population. Unweighted particulate emissions, measured as tonnes emitted, was suggested as a proxy for rural air quality, covering health and visibility impacts, and was subsequently adopted on the recommendation of a simple majority of the Consultative Committee.

ATTRIBUTE 8: GREENHOUSE GAS EMISSIONS

Increase in atmospheric concentrations of carbon dioxide and methane (among other gases) has led to considerable concern and investigation into the global ‘greenhouse effect’. The greenhouse effect refers to a warming of the earth’s temperature, with associated changes in weather

12 SOx can also come from aerosols which contribute to fine particulates and visibility degradation.
13 The 100 km radius area serves as a proxy for the area of impact.In some circumstances and locations – and particularly for project-level analysis – boundaries of a defined airshed may be more appropriate.
14 ARA Consulting Group and Bovar-Concord Environmental (1994), *Clean Air Benefits and Costs in the GVRD*. Prepared for Greater Vancouver Regional District and BC Ministry of Environment,Lands and Parks.
15 Health impacts from fine particulates arise from both direct emissions and through formation of fine particulates through atmospheric reactions of NOx and SOx emissions.The values from the ARA/Concord study include these secondary fine particulate impacts in the NOx and SOx values.Source: ARA Consulting Group based on values in *Clean Air Benefits and Costs in the GVRD* (1994).

GREENHOUSE GAS EMISSIONS

Tonnes of carbon dioxide (CO_2) equivalents where:

- *CO_2 equivalents are carbon dioxide plus methane emissions converted to CO_2 equivalents using the global warming potential factor of 11 (Resource Acquisition Policy).*

and atmospheric conditions (i.e., climate change). Although the scientific basis and policy environment for management of global warming is still uncertain, the provincial and federal governments have committed to stabilizing emissions of greenhouse gases at 1990 levels by the year 2000.

The trade-off attribute used to capture greenhouse gases includes emissions of methane (CH_4) and carbon dioxide (CO_2), the major component of greenhouse gases, measured in tonnes of carbon dioxide equivalents.[16] Greenhouse gas emissions were monetized using a value of $15 per tonne and $40 per tonne in a scenario analysis (Chapter 7).

ATTRIBUTE 9: UPSTREAM AIR EMISSIONS

Although not originally included in the RCF, some members of the Consultative Committee expressed concern that the trade-off attributes discussed above understate the environmental implications of natural gas-fired generation. They argued that impacts associated with production and distribution of fuels (e.g., life cycle impacts) should not be ignored and, if excluded, would result in inconsistent treatment compared with hydroelectric resource options. Characterizing all production and distribution impacts – referred to as upstream impacts – was beyond the scope of this Plan.

However, it was agreed that upstream air emissions could serve as a proxy for a broad range of upstream impacts of natural gas (e.g., land and water impacts as well as other air emissions such as hydrogen sulfide), not just greenhouse gases. Although partially addressed through this proxy, capturing the full environmental implications of natural gas use requires a more comprehensive assessment of air, water and land impacts upstream of the power plant. Upstream impacts of other fuels (e.g., coal) were not considered.

Upstream air emissions include carbon dioxide and methane emissions, estimated at about 16 percent of CO_2 emissions at combustion.[17] Local air pollutants (e.g., NOx) were not included because upstream emissions of these pollutants are negligible. (Specifically, NOx emissions are estimated to represent about 0.086 percent of NOx emissions at combustion. Given this small increment, it was thought that NOx emissions are adequately captured under the attribute "Local Air Emissions.")

UPSTREAM AIR EMISSIONS

Tonnes of upstream emissions of greenhouse gases (CO_2 equivalents) where:

- *emissions include carbon dioxide and methane; and*
- *emissions are estimated at 16 percent of CO_2 emissions at combustion.*

ATTRIBUTE 10: ELECTRIC AND MAGNETIC FIELDS

Electric and magnetic fields (EMF) are created by the use and transmission of electricity. EMF are present in households, offices, commercial buildings and also around transmission and distribution lines used to transfer electricity from points of generation to the main load or customer centres. Although the science is preliminary, evolving and controversial, some believe that exposure to low frequency (including 60 Hz power frequency) magnetic

16 Carbon dioxide and methane emissions were aggregated by converting methane to CO_2 equivalents. A conversion factor of 1 tonne of CH_4 equals 11 tonnes CO_2 was used.The latest estimate from the International Panel on Climate Change is a conversion factor of 1 tonne of CH_4 equals 24.5 tonnes CO_2.

17 That is, for every 100 tonnes of CO_2 emitted at combustion (at the power plant),an additional 16 tonnes are emitted during production and distribution of that fuel. Source:Gas Technology Canada (1994), *1990 Air Emissions Inventory of the Canadian Natural Gas Industry.*

EMF

Milli-gauss-persons of incremental magnetic field exposure in the final year of the plan (2014/15).

fields (MF) can increase the risk of some forms of cancer, hence the concern over proximity to electrical equipment such as transmission and distribution lines. Exposure to low frequency electric fields, sometimes referred to as electrostatic fields, is not considered to pose any health risk.

Although the primary concern related to MF is health, no generally accepted relationship between the amount of MF exposure and cancer incidence has been developed. Consequently, the trade-off attribute focuses on a measure of MF exposure, not health impact. It takes into account:

- system-wide changes in power flows (i.e., on existing transmission lines as well as new lines);
- representative magnetic field values for different sections and types of transmission lines;
- population exposed.

The resulting measure is expressed as milli-gauss-persons of incremental exposure, where milli-gauss is the measure of field and persons is the measure of population exposure.

There are a number of complexities in calculating this measure, such as the level of detail for population and magnetic field estimates. For this Plan, and in keeping with the Consultative Committee's suggestion that limited effort be placed on characterizing EMF, magnetic field strengths were based on typical line construction for overhead lines of different voltage classes (60 kV to 500 kV) as well, population estimates are approximate. Although coarse, the resulting magnetic field exposure estimates were useful in meeting the Consultative Committee's desire to identify whether exposure levels increase, decrease or stay the same as a result of the required transmission sequence of a portfolio.

5.3.5 Social/Community Trade-Off Attributes

The social/community account captures impacts related to community well-being and human-based resources. The RCF covers issues such as land use and status, recreation and tourism, archaeology and heritage resources, health and safety, aesthetics (e.g., vistas, noise), community infrastructure and community services. For example, some resource options may require an influx of a large construction workforce, which could place pressure on local infrastructure (e.g., housing, waste and sewage treatment) and services (e.g., policing). Other projects may threaten local heritage resources.

ATTRIBUTE 11: LAND USE

In determining a trade-off attribute, discussion among the Consultative Committee focused on land use. A combined measure reflecting recreation, aesthetics and land use status was suggested but set aside in favour of a simple definition of the number of hectares alienated by each project.

LAND USE

Number of hectares lost (excluding special zones) where:

- *'number of hectares' includes land owned privately, by BC Hydro or the Crown; and*
- *'lost' reflects a long term change in land use or land use potential.*

Note: Loss of special zones is captured in the attribute "Terrestrial ecosystems".

5.3.6 Economic Development Trade-Off Attributes

ATTRIBUTE 12: EMPLOYMENT

The economic development account is intended to reflect the impact that a particular resource option or portfolio has on economic activity. These impacts may be at the regional or provincial level. Based on the RCF, interests of BC Hydro's managers and the Consultative Committee, this trade-off attribute focused on regional employment as the measure of economic development impacts.[18]

Resource projects or portfolios may present economic opportunities (e.g., project related employment or improved recreation facilities). However, through land and water impacts, they may also compromise existing economic activity (e.g., fishing or trapping activity). Both effects are included in the definition of the trade-off attribute. However, quantitative estimates of resource-related employment impacts are not generally available; where important, qualitative impacts are included in the Resource Summaries (Appendix E).

The Crown Corporations Secretariat *Guidelines to Multiple Account Evaluation*, the *Resource Acquisition Policy*, and the RCF developed for this Plan specify that only new job creation be included in the measure of employment impacts. 'New' jobs take into account the extent to which the project benefits those who are un- or under-employed, rather than redistributing currently employed individuals. Such assessments may be based, in part, on unemployment rates by job classification and region.

The trade-off attribute used in the Plan measures total job creation/loss. The component of employment creation that is 'new' is not estimated because of the difficulty in providing adequate adjustments for unemployment implications.

The Consultative Committee had several discussions regarding the treatment of demand-side management related employment. Demand-side management related employment can be separated into two components:

EMPLOYMENT

Person-years employment where:

- *for supply-side projects, includes direct employment for construction and operations (operations employment is calculated as annual average jobs multiplied by the number of years that facility is in operation over the planning horizon, as determined for each resource portfolio);*
- *for demand-side management projects, includes investment and respending employment;*
- *considers both employment gains from project activity and employment losses due to resource impacts (e.g., tourism, forestry).*

(i) Investment Employment:

Employment from investment in the program, including program design and administration and actual construction and/or services required to implement programs. (As with supply-side projects, only direct employment from investment expenditures is included in the measure.)

(ii) Respending Employment:

Employment from the respending of direct bill savings (net of rate impacts). Specifically, lower electricity bills 'free up' income that may then be spent on a variety of consumer goods and services, which generates employment. However, higher rates among non-participants increases electricity bills which reduces income that may be spent on consumer goods and services, thus offsetting the above bill saving benefits. These rate impacts are subtracted from the direct bill impacts for a net respending effect on employment.

There is no industry standard regarding the treatment of demand-side management employment and members of the Consultative Committee differed significantly in their opinions as to whether respending effects should or should not be included. Some viewed bill savings as induced expenditures, similar to a multiplier effect and

18 Employment is a proxy measure for economic development impacts. As suggested by one member of the Consultative Committee, it may be a crude measure. Further refinements could examine alternative measures such as local domestic product.

felt they should not be included for demand-side management options without being included for the supply-side options. Other members argued that bill savings impacts are unique to demand-side management; they stem from direct reductions in energy consumption and energy bills, and so differ from traditional multiplier effects. As no resolution was reached, the trade-off attribute was defined to include respending effects; however, estimates that included only investment effects for demand-side management were also provided.

5.3.7 Differences Between BC Hydro and Consultative Committee

The set of attributes adopted by BC Hydro and the Consultative Committee and were the same, with two exceptions. First, BC Hydro policy excludes upstream impacts from consideration in project analyses as these would be considered in approvals for natural gas activities. Second, BC Hydro's policy on EMF concludes that there is insufficient scientific evidence linking transmission-line exposure and health impacts to warrant significant expenditures to mitigate EMF exposure. Also, setting standards for EMF exposure currently lies outside the Corporation's responsibility.

5.3.8. Linkages to the Plan's Objectives

The trade-off attributes were intended to reflect the range of objectives for the Plan. Table 5.4 indicates the linkages between the Plan's objectives and the trade-off attributes.

As shown, most high-level Plan objectives were addressed by at least one attribute while some objectives are linked with many attributes. For example, the objective to "Minimize adverse and promote positive environmental impacts" is addressed by seven attributes, reflecting the breadth of the objective and the complexity of its individual parts. Other objectives are represented by just one or no trade-off attributes. These are as follows:

- Objective 2, "quality service", is captured within the fundamental criteria of the Plan; namely, the selected portfolio is required to meet minimum acceptable levels of reliability. These minimum levels maintain quality service, as defined in the Plan's objectives.
- Objective 4, "choice for customers", is partially captured in the diversity index. However, the availability of choice in rates and services is also an issue, which is captured by specific reference to the treatment of rate options and new product development in the Plan.
- Objective 8, "fair and equitable treatment", is not represented by a trade-off attribute. Identifying a suitable trade-off attribute was complicated by the array of issues under this objective, ranging from transfer of wealth among different groups to assessment of electrical service options. Part of the objective was captured in the planning process itself, coverage of a wide array of possible resource options and evaluation of those options using a consistent set of attributes.
- Objective 9, "implementation of appropriate and new technology", is represented in part by the diversity index. The contribution of any portfolio to this objective is also reflected in the breadth of the resource inventory considered in the planning process and the technology choices represented in the final portfolio.

5.4 Characterization of Resource Options

5.4.1 Background

The previous two sections outlined what was considered in developing the Plan (Section 5.2, List of Resources) and how they are to be evaluated (Section 5.3, Attributes). The purpose of this section is to apply the attributes to each resource type in the list of resources. This 'characterization' describes each resource relative to each attribute and, in so doing identifies its strengths and weaknesses.

This section does not recommend or select resources. Rather it provides an overview of the characteristics of all resources in the inventory. Specific resources are selected through portfolio development and evaluation as discussed in Chapters 6 and 7.

Table 5.4:

Linkages Between Planning Objectives and Trade-off Attributes

Account	Attribute	Minimize costs of electrical services to customers	Provide quality service that meets customer needs and expectations	Provide flexible service to adapt to changes	Provide choice to customers regarding electricity services	Minimize adverse and promote positive environmental impacts	Minimize health and safety impacts	Optimize socio-economic impacts	Ensure fair and equitable treatment	Promote implementation of appropriate new and existing technology
ECONOMIC DEVELOPMENT ACCOUNT	Employment							✓		
SOCIAL/COMMUNITY ACCOUNT	Land Use							✓		
ENVIRONMENTAL ACCOUNT	EMF					✓	✓			
ENVIRONMENTAL ACCOUNT	Upstream Air Emissions					✓				
ENVIRONMENTAL ACCOUNT	Greenhouse Gas Emissions					✓				
ENVIRONMENTAL ACCOUNT	Particulate Emissions					✓				
ENVIRONMENTAL ACCOUNT	Local Air Emissions					✓	✓			
ENVIRONMENTAL ACCOUNT	Terrestrial Ecosystems					✓				
ENVIRONMENTAL ACCOUNT	Species Persistence					✓				
TECHNICAL ACCOUNT	Diversity Index			✓	✓					✓
FINANCIAL ACCOUNT	Rate Impact	✓								
FINANCIAL ACCOUNT	PV System Cost	✓						✓		
ATTRIBUTE	Objectives									

RESOURCE SUMMARIES

Each of the more than 100 projects or programs in the inventory were characterized, which includes the transmission facilities required to connect a generation facility to the existing transmission system (where information was available). Production and distribution of fuel supply was not included, except through the proxy attribute "upstream air emissions." The data and information from the characterization of individual projects and programs is documented in Appendix E.

A variety of information sources were used to determine attribute values for each resource project or program. In general, information on BC Hydro options was gathered from feasibility studies, project information, environmental assessment reports and technical documents produced either by BC Hydro or outside consultants. Financial information on private power projects was taken from proposals submitted in response to the 1994 Request for Proposals; environmental and social information from the accompanying social evaluation reports and the external consultants'review of those reports. Information on the Columbia Power Corporation projects was drawn from BC Hydro's *1994 Electricity Plan* (Brilliant and Waneta) or the Energy Project Certificate application (Keenleyside). Other information sources included market information, published reports and, in the case of alternative technologies, interviews with experts in Canada and abroad.

The information was based on the best available data at the spring of 1995. Much of the data, especially on alternative technologies and additional demand-side management programs, are highly uncertain. In some cases, lack of information precluded quantifying all trade-off attributes.

The characterization of resource options is conducted at a planning level, appropriate for strategic-level decisions. Some options are further along in the development process, thus greater levels of information are reflected in the Resource Summaries. This notwithstanding, each resource option will be subject to further assessment, in particular, through any regulatory or licencing process (e.g., the Environmental Assessment Act).

CHARACTERIZATION BY RESOURCE TYPE

The detailed data presented in the Resource Summaries provided the information on which the portfolio modeling and analysis was based. This section aggregates project-specific information from the Resource Summaries to provide a general overview of the relative strengths and weaknesses of different resource types. The resource types considered are the same as those discussed in Section 5.2 – alternative technologies, hydroelectric, thermal, purchases, community energy planning, demand-side management, rates and transmission (summarized in Table 5.1).

Each resource type is described according to nine of the twelve trade-off attributes discussed in Section 5.3. Characterization of EMF, diversity and rate impacts is discussed at the portfolio level (see Chapter 6) as these attributes depend on the total mix of resources and their collective impact.

The results for greenhouse gas (GHG) emissions and upstream air emissions are presented together. Although they represent different environmental concerns (see Section 5.3), they generally pattern each other, reflecting the fact that upstream air emissions are calculated as a percentage of carbon dioxide equivalent emissions at combustion. Conversely, two measures of employment are presented separately (construction and permanent job creation) because these two measures of the same attribute do not pattern each other. Finally, the attribute "present value of system costs" is represented in the characterization by "levelized unit economic costs" as discussed in Section 5.3.2.

5.4.2 Alternative Technologies

Although BC Hydro collects information, monitors the development and is involved in some research and development of alternative technologies, the existing system does not include a significant amount of alternative technologies.[19] BC Hydro currently maintains supporting equipment (transformers, lines, poles, etc.) for the 50 kW Christopher Point wind turbine on Vancouver Island, owned by Natural Resources Canada. In 1995 BC Hydro and Powertech took responsibility for the electrical interconnection of the fuel cell operating at the Mohawk refinery in North Vancouver.

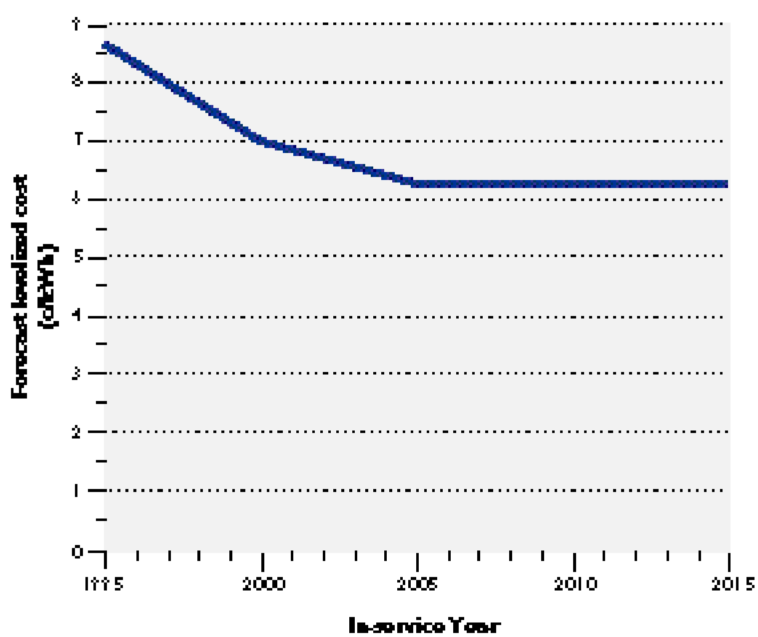
To explore the possible role of alternatives, this Plan examined the following five examples of alternative technologies: freestream tidal, fuel cells, solar photovoltaic, wave and wind.

Most of the above technologies are dependent on natural conditions (e.g., tidal, wind) which may or may not be available to generate energy during peak demand periods. Consequently, alternative technologies offer energy but are attributed a low dependable capacity contribution. Overall, a maximum of 150 MW of dependable capacity and 1,160 GWh of energy are assumed to be available from alternative technologies by the end of the planning period, or about 4 percent of total additional capacity and energy needs.

The cost of alternative technologies is currently high relative to conventional hydroelectric and thermal options, ranging from about 9 ¢/kWh (wind) to over 22 ¢/kWh (solar photovoltaics).[20] Although the costs are likely to decline as the technologies develop, costs are nevertheless expected to remain high relative to other resources throughout the planning period. Costs of about 4 ¢/kWh to 16 ¢/kWh by the year 2015 were used as a rough guide for the purposes of long-range planning. Figure 5.3 provides an example of a forecast cost reduction curve for wind energy. As indicated, the costs for wind energy are expected to decline to just over 6 ¢/kWh during the latter half of the planning period.

One of the main features – and attractions – of alternative technologies is modest environmental and social impacts. Land and water impacts are generally low, due in part to siting flexibility and the renewable nature of most of the 'fuels'(e.g., wind). Furthermore, environmental con-

Figure 5.3:
Representative Cost Reduction Curve for Wind Energy (Class 3)



19 The terms alternative technologies and renewables are sometimes used interchangeably. If renewables such as wood residue and small and medium hydroelectric were included in the definition of alternative technologies, then BC Hydro's involvement in implementing these types of resources would be substantial. For example, since 1989 BC Hydro has contracted approximately 250 MW of small and medium hydroelectric and wood residue facilities. Also, 116 MW of small and medium hydroelectric and 83 MW of wood residue were included on the short list prepared by BC Hydro in response to the December 1994 request for proposals (Table 8.2, Chapter 8).

20 Economic costs calculated as corporate costs less transfers (see Section 5.3.2).

straints and impacts may be easier to manage as a result of the relatively small size of alternative energy generating systems. Actual environmental impacts would be site-specific and warrant evaluation at the project level.

Land use is also relatively low, with two exceptions: wind energy and solar photovoltaic. Wind farms can co-exist with other land uses (e.g., farming), so only the land required for the wind turbine platforms is considered to be alienated. On the other hand, land requirements are much higher for solar photovoltaic installations due to the surface area required to capture the solar radiation. Even though the panels are somewhat raised and angled from the ground, multiple uses of the land (as in the wind farm case) are not likely.[21]

In general, alternative technology units can be pre-assembled and delivered to the site for final set-up, with relatively little construction employment impacts. Because of the small size of most units, operations and maintenance requirements are low, with likely negligible impact on permanent job creation in any particular region.

In summary, the outstanding features of alternative technologies are high cost but good performance on environmental attributes. Land use is modest except for solar photovoltaic and wind farms, while employment creation is moderate.

5.4.3 Hydroelectric Generation — Energy Projects

Hydroelectric resources make up the majority of BC Hydro's existing power generation facilities, due in part to the natural abundance of water systems in the province. The hydroelectric resource options identified for the Plan reflect this same richness. Hydroelectric energy resources are divided into three categories:

- Resource Smart – design and operational modifications at existing facilities to capture efficiency benefits.
- Augmented generation – additions to/expansions of generation at existing facilities, including new diversions of water, installation of additional generating facilities or new or replacement power plants at existing dams.
- New facilities – new storage (reservoir) and run-of-river hydroelectric facilities, consisting primarily of small and medium projects and including 16 proposals from private power producers.

The individual hydroelectric projects in each category are listed in Table 5.5

Possible hydroelectric capacity resources are discussed in the subsequent section.

In total, the hydroelectric energy resources identified in the inventory could provide over 15,000 GWh/year of energy and 2,800 MW of capacity, or about 60 percent of total needs over the planning period. As shown in

Table 5.5:

Hydroelectric Generation Projects

RESOURCE SMART	AUGMENTED GENERATION	NEW FACILITIES
Ash River Upgrade	Barnes Creek	Peace Site C
Kootenay Canal Upgrade	Duncan	Small & Medium Hydro
Seton Upgrade	Seven Mile Unit 4	
Other Resource Smart	Stave Falls	
	Brilliant Expansion	
	Keenleyside	
	Waneta Expansion	

21 Rooftop solar photovoltaic systems are more likely to be implemented by customers whereas ground-level systems are more applicable for utility-scale applications.

Figure 5.4, these resources are available over a wide range of costs. About 4,000 GWh/year is available at or below 3 ¢/kWh, (unit economic cost of firm energy at the Lower Mainland) rising to almost 11,000 GWh/year at or below 4.5 ¢/kWh and 15,000 GWh/year at or below 7 ¢/kWh..

Hydroelectric energy resources are not considered to produce local or greenhouse gas emissions.[22] However, impacts on other environmental and social/community attributes vary. The possibility of a significant decrease in the local population of a red or blue-listed species was identified in four of more than 30 individual projects. The species in question are bull trout, white sturgeon, speckled dace (aquatic species) and water shrew (wildlife). Impacts associated with other individual resource options were not identified, although effects on abundance (as opposed to persistence) have not been evaluated.

Because of their size and incremental nature, few hydroelectric energy resources in the inventory are expected to alienate terrestrial ecosystems, although projects that require significant new or expanded transmission lines to connect to the existing transmission system may affect recreation reserves, wetlands and grasslands (e.g., Peace Site C). Overall, hydroelectric energy resources perform moderately to well on environmental attributes relative to other resource types.

With two exceptions, hydroelectric energy projects have low land requirements. The two exceptions are Duncan (which would require about 315 hectares of land for a 90 km transmission line) and Peace Site C (which requires additional land other than terrestrial ecosystems for the reservoir, facilities and transmission).

Hydroelectric energy resources do not typically create permanent employment relative to other options. However, with the exception of Resource Smart initiatives, hydroelectric projects create considerable construction employment relative to other resource types.

In summary, the province has an abundance of hydroelectric resources that are available over a range of costs. Because of the incremental nature of most projects, environmental impacts are modest relative to other resource types in the inventory, with the exception of species persistence impacts at some new facilities and augmented generation sites. Land requirements are also low with the exception of two specific options which require new transmission lines to connect to the main grid. Notwithstanding their incremental nature, many projects create construction employment.

5.4.4 Hydroelectric Generation — Capacity Projects

Increasing capacity adds flexibility to the BC Hydro system to respond to peak periods, changes in load or outages at other facilities. There are five hydroelectric generation projects which could add capacity to the existing BC Hydro system: (i) Mica 5, Mica 6, Revelstoke 5, Revelstoke 6 and (ii) pumped storage. The Mica and Revelstoke projects would be located at their respective existing facilities. Pumped storage is a variation of conventional hydroelectric technology. For this Plan a ‘generic’ or representative pumped storage configuration which involves creating two new reservoirs with a powerhouse between them was developed.

The Mica and Revelstoke options add capacity but not energy as the total amount of water running through the facilities would not change. For pumped storage, electricity generated during the off-peak period is used to pump water from a low-level reservoir to a higher-level reservoir. During peak periods the flow is reversed for operation like a conventional hydroelectric facility. While providing capacity, pumped storage consumes energy.

The economic unit cost of capacity delivered to the Lower Mainland for the Mica and Revelstoke projects ranges from $32 to $51 per kW/year which is less than half the estimated $133 per kW/year for the pumped stor-

22 The carbon cycle of new reservoirs is site specific and not well understood. As information becomes available, greenhouse gas emissions may be quantified for new reservoir projects. Existing BC Hydro reservoirs and new reservoirs are not attributed with greenhouse gas emissions.

Figure 5.4:

Supply Curve For Hydroelectric Energy

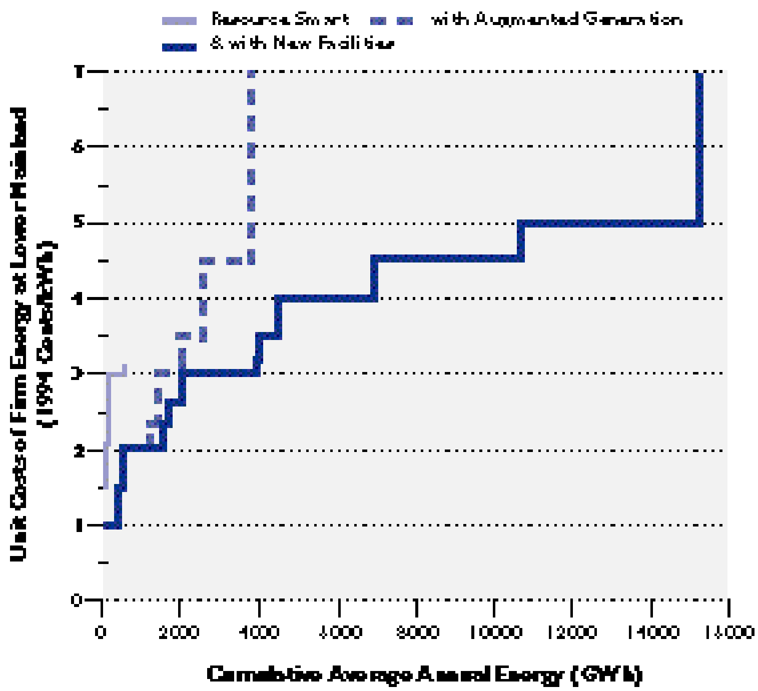
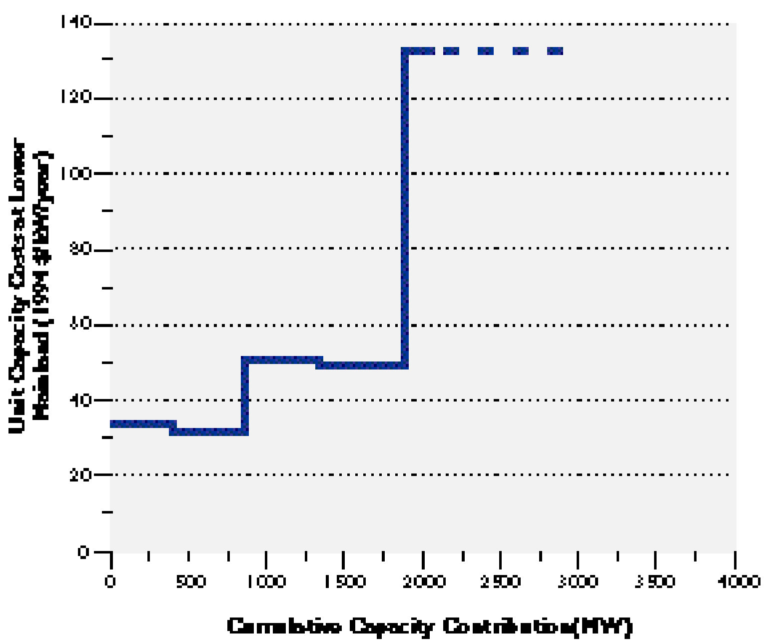


Figure 5.5:

Supply Curve For Hydroelectric Capacity



Note: Although Revelstoke Unit 6 has a lower unit cost than Revelstoke Unit 5 the fifth unit must be installed before the sixth.The same is true for Mica 5 and Mica 6.

age resource. Figure 5.5, Supply Curve for Hydroelectric Capacity, shows the capacity available at these costs. The dotted line represents the potential for larger capacity or additional pumped storage options. As defined in the inventory, these projects could add over 2,000 MW of dependable capacity or slightly more than half of the estimated amount required by the end of the 20-year planning period.

The capacity resource options are not attributed with local air or greenhouse gas emissions. Also, impacts to fish and aquatic systems are not significant as flow changes are minor. Impacts to wildlife or plant species and terrestrial ecosystems are not anticipated. The amount of land required for the Mica and Revelstoke projects is minimal (one hectare in total for Mica 5 and 6)[23] unlike the large amount of land (140 hectares) required for the pumped storage option.

Due to the large scale of these resource options, a great deal of construction employment is created. However, because the Mica and Revelstoke projects are additions at existing facilities, no permanent employment is created for these four resource options. The pumped storage option would likely be operated by remote control.

In summary, capacity project impacts are specific to either the Mica and Revelstoke options or pumped storage. The Mica and Revelstoke projects have relatively low costs whereas pumped storage is much higher. These projects do not have significant environmental impacts with the exception of pumped storage which has the potential to negatively impact land use. All projects are expected to create construction-related employment. Note: Although Revelstoke 6 is cheaper than Revelstoke 5 the fifth unit must be installed before Revelstoke 6. The same is true for Mica 5 and 6.

5.4.5 Thermal Resources

Four types of thermal resources are included in the 1995 resource inventory:

- natural gas (using combustion or steam engines or turbines);
- wood residue (with or without natural gas dual-fuel capability);
- coal (using fluidized bed combustion as an example of an advanced coal technology); and
- geothermal (utilizing natural heat sources in the earth’s crust).

ENERGY CAPABILITY AND COST

Apart from the Burrard Thermal Generating station located in the Vancouver area, natural gas generation does not account for a large proportion of total generation in the existing BC Hydro system. However, lower fuel prices, technological developments and siting considerations have enhanced the attractiveness of natural gas-fired generation.

The response to BC Hydro’s 1994 request for proposals from private power producers demonstrates the current competitiveness of natural gas projects, as they accounted for about 80 percent of capacity offered from all bids. Added to this potential are opportunities for changes at BC Hydro’s Burrard plant, such as upgrading all six existing steam units or replacing (repowering) up to four units with high efficiency combined cycle combustion turbines.

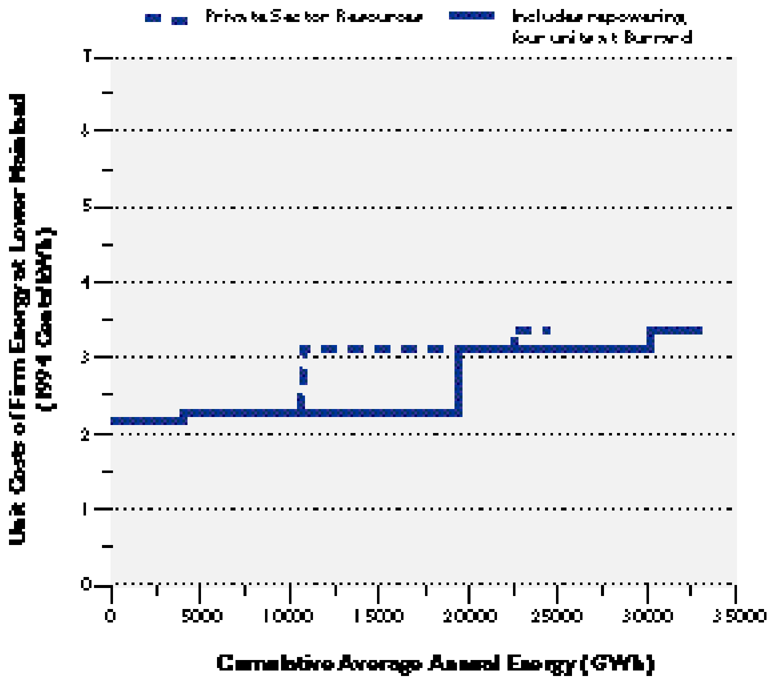
Although subject to gas infrastructure constraints, the combined resources from private power projects and repowering at Burrard amount to more than 33,000 GWh of average annual energy and 4,400 MW in dependable capacity, more than the Plan’s total requirements over the planning period.

Unlike most other resource types, the costs of natural gas-fired generation are clustered in the 2.2 ¢/kWh – 3.3 ¢/kWh range (unit cost of firm energy at the Lower Mainland). Figure 5.6 illustrates the amount of energy available at the different costs. The dotted line shows

23 The land required for a capacitor station associated with the Mica 5 and 6 projects would almost entirely be located on an existing right-of-way, under the existing transmission line. For pumped storage, it was assumed that sensitive terrestrial ecosystems will not be impacted.

Figure 5.6:

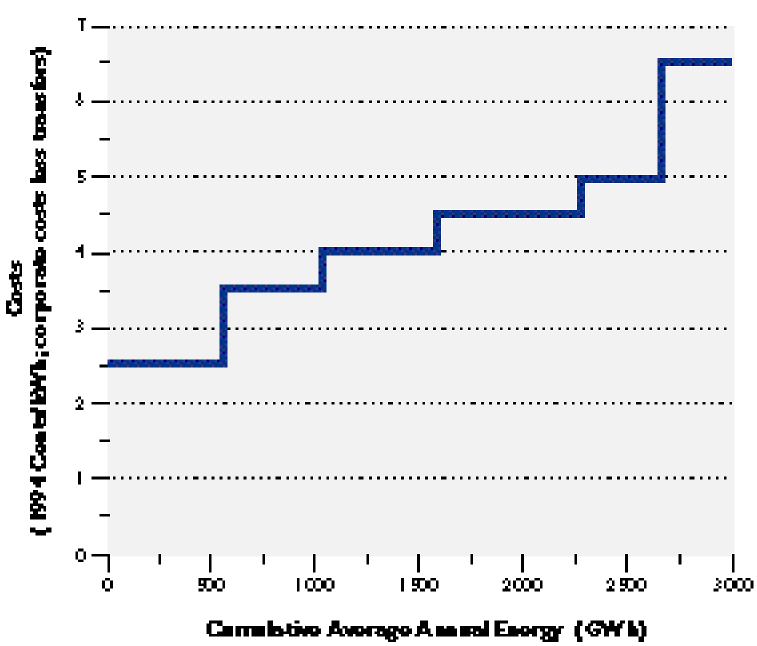
Supply Curve For Natural Gas Generation



Note:The energy and unit cost for repowered Burrard,as shown on the supply curve, are based on an expected utilization of 8,500 GWh per year in a portfolio context. The total capacity of Burrard is expected to be 11,100 GWh per year.The capability of the existing plant is 6,900 GWh per year.

Figure 5.7:

Supply Curve For Wood Residue Generation



availability from private power projects, the solid line includes full repowering (i.e., four modules) at Burrard.

With the exception of the Williams Lake plant and a couple of self-generation facilities, BC Hydro currently has no wood residue-fired generation facilities in the system. However, the potential of wood residue as a fuel source for electricity generation has gained increased attention with the introduction of legislation requiring closure of all beehive burners (the primary method for wood residue disposal) starting in January 1996.[24]

13 wood residue proposals were received in response to BC Hydro's 1994 Request for Proposals, offering about 3,000 GWh in average annual energy and 380 MW capacity. These values represent about 12 percent of energy and 10 percent of capacity requirements of the Plan. Costs range from about 2.5 ¢/kWh to 6.1 ¢/kWh, as indicated in Figure 5.7.

The inventory also includes a geothermal resource based on a 70 MW project proposed in response to the 1994 Request for Proposals (555 GWh per year), for which prices are confidential. A fluidized-bed coal resource is included based on a 200 MW (1,490 GWh/year) plant in the East Kootenay area, for which energy costs are roughly estimated at 4.5 ¢/kWh.

ENVIRONMENTAL CHARACTERIZATION

From an environmental perspective, most thermal resources differ significantly from hydroelectric or demand-side resources. Land and water impacts, based on the trade-off attributes for the Plan, are relatively small while air emission concerns are more pronounced.

Land and water impacts are low, partly because many projects are located in urban (usually industrial) settings at existing facilities. Furthermore, they generally do not require significant transmission line developments. The geothermal project proposed by a private power producer is an exception. The project includes construction of a new 80 km transmission line which would alienate about 320 hectares of undisturbed pristine lands for rights-of-way. Concerns related to discharge of heated water from thermal plants may exist, but are site-specific and have not been characterized. Possible negative impacts on aquatic species (particularly salmon) and mitigative measures are being studied at Burrard; assessment of the implications for private power proposals was limited by lack of information provided in the proposals.

The environmental profile of thermal resources is dominated by air emissions. In the case of natural gas-fired generation, air emissions are high relative to other resource types (over 300 tonnes of greenhouse gases per GWh compared with zero emissions for augmented hydroelectric energy projects and demand-side resources). As most facilities would be located in urban areas, population-weighted local air emissions are also high for natural gas-fired generation, a characteristic that could constrain siting of new thermal plants. Air emissions from coal-fired generation are higher than for natural gas-fired sources (e.g., greenhouse gas emissions of more than 800 tonnes/GWh). Any proposed facility would be required to meet emission control permitting requirements which are currently based on Best Available Control Technologies (BACT).

Geothermal and wood residue resources, on the other hand perform well on air emission attributes.[25] Consistent with provincial, federal and international policy, greenhouse gas emissions from wood residue generation are not counted.[26] Wood residue projects also offer opportunities to reduce emissions of local air pollutants (i.e., nitrogen oxides, sulfur oxides and especially particulate matter) either through the substitution of incinerators[27] or replacement of old power boilers in favour of new, more efficient boilers.

Some members of the Consultative Committee questioned the conclusion that wood residue resources did

24 There are also a number of private wood residue power generation facilities in operation.
25 Potential hydrogen sulphide emissions for geothermal resources were not considered.
26 This policy is based on the premise that wood residue is a renewable resource and that replanted trees take up (absorb) the same level of greenhouse gases as emitted upon combustion.
27 Incinerators are required to replace beehive burners.

actually reduce local air emissions. Specifically, some members were concerned that indirect emissions associated with the transportation of wood residue to the site and site-specific issues such as the concentration of emissions in a sensitive urban airshed were not taken into account. Furthermore, concern was expressed that increased NOx emissions increase secondary PM-10 emissions.

SOCIAL/COMMUNITY AND ECONOMIC DEVELOPMENT CHARACTERIZATION

Land use for most thermal projects is relatively low, with the exception of the geothermal resource that requires land for transmission lines.

Thermal resources have moderate employment impacts, both during construction and operations. Wood residue, coal and geothermal resources tend to be more labour intensive than natural gas resources.

In summary, natural gas-fired generation is characterized by low cost, low impacts on land use as well as land and water resources and modest employment opportunities. However, coal and natural gas-fired generation could significantly increase greenhouse gas and local air emissions relative to other resource types. While some inexpensive wood residue projects were submitted under the 1994 Request for Proposals, unit costs are generally higher than for natural gas-fired options. From an environmental/social perspective, wood residue has distinct advantages of reducing local air emissions in some locations while not contributing to greenhouse gases and providing modest levels of permanent employment. Geothermal resources differ from other thermal resources in their environmental characterization, with land use and terrestrial ecosystem impacts dominating air quality issues.

5.4.6 Purchases

The BC Hydro system is connected to other electrical systems through various transmission inter-ties with TransAlta Utilities (to Alberta) and Bonneville Power Administration (to the United States). These connections enable BC Hydro to both export to and import from other jurisdictions. Imports from Alberta are coal or natural gas-fired; imports from the United States are generally treated as a composite of coal, oil and natural gas-fired generation.[28]

Purchases considered in this Plan include:

- imports from Alberta (coal, natural gas);
- imports from the United States (coal, oil, natural gas);
- Alcan; and
- the Canadian Entitlement to the Columbia River Treaty downstream benefits.

With respect to the financial and technical attributes, imports perform well relative to other resource options. In particular, considerable amounts of energy (about 5,600 GWh) are expected to be available at 3.2 ¢/kWh or less delivered to the Lower Mainland, as shown in Figure 5.8. However, heavy reliance on non-firm imports does not serve capacity needs and could leave BC Hydro vulnerable to high spot market prices.

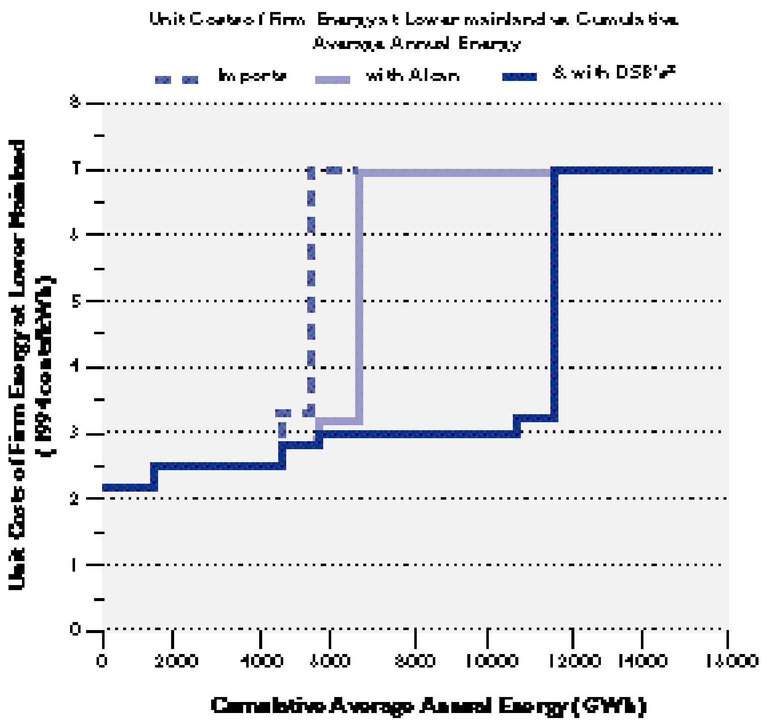
Among the environmental, social/community and economic development accounts, the main concern with imports is air emissions – both greenhouse gas emissions as well as local air emissions. Emission factors vary considerably depending on the type of fuel used and, in the case of local air emissions, the location of that generation. In general, because of the coal component, emission factors for imports are generally higher than emission factors for domestic thermal resource options (e.g., Burrard repowering and independent power projects).

Current purchases from Alcan are about 1,750 GWh/year, but are expected to fall to about 1,225 GWh/year at approximately 2.85 ¢/kWh (unit economic cost of firm energy at Lower Mainland). These purchases will not result in any incremental environmental or social implications as they simply maintain existing activity. However,

28 Imports from the United States could also originate from nuclear generation. For the purposes of this analysis, U.S.imports are assumed to be fossil-fuel based.

Figure 5.8:

Supply Cur ve for Purchases



Note: For scenario analysis downstream benefits (DSBs) have been assumed to be available to BC Hydro at 3 ¢/kWh.The actual pricing would depend on availability and market conditions.

should BC Hydro choose to exclude Alcan purchases from the Plan, additional impacts would be incurred by replacement sources, such as generation from new fossil-fueled generating plants with consequent impacts on greenhouse gas and local air emissions.[29]

The return of the Canadian Entitlement to the downstream benefits from the Columbia River Treaty could provide up to 4,900 GWh/year in energy, or about 20 percent of the total additional energy required by the end of the planning period. Because of this amount (including implications for selection and timing of other resource options) and the considerable uncertainty over the final disposition of those benefits, the downstream benefits are treated as a scenario rather than a resource option. This is discussed in Chapter 7.

In summary, three observations about purchases result. First, a considerable amount of energy is potentially available through imports; however imports are not expected to serve capacity needs. Local air emissions are typically higher than domestic thermal resources due to the coal component of imports. Second, Alcan purchases add both energy and capacity to the BC Hydro system with no incremental environmental or social impact. However, if Alcan purchases are not continued, impacts associated with replacement resources would be incurred. Third, because of the uncertainty as to the amount and/or availability of downstream benefits, the energy and capacity implications for porfolios are explained in a scenario in Chapter 7.

29 If the power is sold in another jurisdiction,the option to not purchase would result in some air emissions credits for reducing emissions in the purchasing jurisdiction. These credits have been calculated. If instead of selling the po wer in another jurisdiction,the water is returned to the Nechako river, the credits would not apply. The environmental implications of returning the water to the Nechako River have not been characterized.

5.4.7 Demand-Side Mana gement

In addition to generation resources, demand may be met through demand-side management measures, community energy planning or changes in rate structure. The following is a summary of demand-side management resources. Community energy planning and rates are discussed in subsequent sections.

Demand-side management (DSM) alters patterns of electricity use as an alternative to generation (supply) resources. Thus, demand-side management includes programs and activities that affect the demand for electricity. The demand-side management resources in the inventory include those in BC Hydro's *Draft 1995 Demand Side Management Plan* and additional programs defined in the Conservation Potential Review (CPR). The programs in the *Draft 1995 Demand Side Management Plan* were designed to be implemented over the next 10 years. The additional Conservation Potential Review programs are considered 'achievable' as defined in the Conservation Potential Review process. Demand-side management programs cover residential, commercial and industrial opportunities.

Maximum energy savings from both the *Draft 1995 Demand-Side Management Plan* and additional Conservation Potential Review programs total about 6,900 GWh per year with a maximum capacity savings of about 1,000 MW. This is just over 25 percent of the energy and capacity required by the end of the planning horizon. The *Draft 1995 Demand-Side Management Plan* programs account for approximately 60 percent of this potential and the additional Conservation Potential Review programs contribute approximately 40 percent. However, it is important to note that these levels would not be reached until the end of the planning horizon, after all programs have been implemented and had maximum time to penetrate the market. The expected time frame for an aggressive demand-side management plan would result in energy savings increasing steadily to about 2,200 GWh/year in the year 2000, rising sharply over the next few years as additional Conservation Potential Review programs are taken up, followed by another steady rise to about 6,900 GWh/year at the end of the planning horizon.

The unit economic cost for the *Draft 1995 Demand-Side Management Plan* programs (including customer costs) averages about 3.0 ¢/kWh and for the additional Conservation Potential Review programs, approximately 6.0 ¢/kWh. Because these are averages, the range of lower and higher cost programs is not evident. There are a significant number of demand-side management and Conservation Potential Review programs ranging from less than 1 ¢/kWh to about 15 ¢/kWh and 20 ¢/kWh respectively. Approximately 2,900 GWh/year are available from the *Draft Demand-Side Management Plan* at 3 ¢/kWh or less; this increases to 4,500 GWh/year when Conservation Potential Review programs are added.

Demand-side management programs can help to minimize the overall cost of system expansion if they cost less than generation and transmission options. Another way to characterize demand-side management initiatives is to measure what happens to customer bills or rates as a result of changes in utility revenues and operating costs caused by the program. Over the long term, customer rates/ bills would decline if the avoided supply costs (decreased revenue requirements) are greater than the costs of implementing the programs. Some of the *Draft 1995 Demand-Side Management Plan* and additional Conservation Potential Review initiatives with low unit costs and significant savings would cause rate reductions over the long term.

Analysis has shown however, that the combined impact of the *Draft Demand-Side Management Plan* initiatives could cause BC Hydro's rates to rise. The rising costs of demand-side management initiatives (many of the least-cost programs have been completed) and the falling costs of new generation may contribute to this situation. The rate impacts are highly dependent on the type of demand-side management initiative, assumptions regarding electricity demand and rates and the resources included in a portfolio.

One of the most frequently discussed advantages of demand-side-management measures is avoiding environmental impacts associated with generation resource development. Impacts associated from disposal or treatment of waste and/or toxic materials that may be associated with specific demand-side management programs (e.g., chlorofluorocarbons from refrigerators – Refrigerator Buy-Back Program) appear to be small. In addition, demand-side management does not have land use impacts or direct social/community implications.

Demand-side maagement creates employment through either investment impacts (i.e., expenditures on programs) or respending impacts (i.e., customers save money on electricity bills thus purchase other goods and services). Generally the respending component of employment is larger than the investment component. As noted in Section 5.3, there is no agreement on the appropriateness of including respending impacts in this analysis. Consequently both investment only and total investment (investment plus respending) are considered. For both, employment benefits vary depending on the specific demand-side management program; however, packages of individual programs – such as the *Draft 1995 Demand-Side Management Plan* – do have potential for moderate employment creation relative to other resource types.

In summary, the impact of demand-side management programs on system costs (including customer costs) will depend on the package of programs selected. The maximum energy and capacity levels would not be reached until the end of the planning period, after all of the programs have had time to penetrate the market. Demand-side management programs have negligible or no environmental and social/community impacts and also create moderate levels of employment. However, depending on the type of programs adopted, demand-side management can increase rates in the short-term.

5.4.8 Community Energy Planning

Community energy planning encourages energy-aware community and land planning, with the involvment of municipal and regional governments, planners, businesses and residents. Initiatives include modifying zoning and building orientation to improve delivery of energy and other services to customers, encouraging compact housing, preserving land for utility corridors and permitting distributed generation. BC Hydro is involved in community energy planning but this option has not been formally included in previous electricity plans as a resource.

Based on a recent review, the potential for energy savings from changes in community energy planning are estimated at about 40 GWh/year. Although expenditures and activities would begin immediately, benefits are not expected for at least five years, rising over the remainder of the planning period. Total savings over a 20-year period are estimated at 400 GWh/year and 75 MW of capacity.

Because of the nature of the resource, unit energy costs have not been calculated. However, preliminary costs and impact estimates suggest community energy planning will not increase rates.

Community energy planning has no identifiable negative impacts on the natural or social environment. Indeed, it may well have positive impacts, including preservation of green space within communities, decrease in automobile use and promotion of alternative modes of transportation (e.g., cycling, transit). In so doing, community energy planning can help to improve most environmental and social/community attributes, including air emissions, terrestrial ecosystems and land use.

Because community energy planning activities are integrally linked to broader planning, decisions, (governments, residents, land planning, etc.) it is not possible to identify specific contributions to employment.

In summary, community energy planning can help to improve most environmental and social/community *attributes, including air emissions and terrestrial ecosystems. It is neutral with respect to rate impacts and employment and provides a low cost source of electrical services.*

5.4.9 Rates

In addition to a group of potential intra-class rate options developed by BC Hydro[30], three rate designs which are characteristic of all classes were discussed with the Consultative Committee: conservation rates, net billing and green rates.[31] Intra-class or 'within the class'means that changes to electricity service prices do not change the revenue collected from that class of customers. Individual customers will notice changes on their bill depending on the time and/or season and the amount of electricity used, but total revenues to BC Hydro will not change. The three rate classes are:

- Residential: Afamily dwelling (i.e., for domestic use).
- General: Other accounts that do not qualify for residential rates but are served at a distribution voltage less than 60 kV.
- Transmission: All accounts served at transmission voltage (greater than or equal to 60 kV).

Some examples of rate options are regional rates – electricity prices that vary by region; seasonal rates – electricity prices which vary depending on the season and time of use rates – electricity prices which vary by the time of day.

The intra-class rate options considered are characterized as capacity resources. Customers respond to rate designs by altering their electricity use patterns which reduces capacity requirements during peak periods and hence the need for additional capacity resources. Rate options typically increase energy requirements as many customers will use less during high priced periods but more than usual during low priced periods.

Some of the individual rate options included in the inventory are mutually exclusive, thus not all of the rate options could be implemented together. For example: you would not require both residential time-of-use and residential real-time pricing rates as electricity pricing for both varies by time of day. Therefore the total contribution of rates as a resource to meet increased demand for capacity cannot be easily calculated. As a point of reference, the estimated maximum capacity supplied by a single rate design in each class is:

- General seasonal 50 MW,
- Residential seasonal 195 MW,
- Transmission real time pricing 195 MW.

If these three rate options were chosen, there would be a reduction of 440 MW from peak capacity demand which is approximately 12 percent of the estimated capacity required over the 20-year planning period.

The majority of the rate options have a unit cost of capacity between $0 to $100 per kW/year. However, three additional rate designs (related to time-of-use rates in the residential and general classes) have costs ranging from $560 to $3,200 per kW/year.

Rates are not expected to have any direct environmental, social/community or employment impacts as they are price-setting tools. Secondary impacts such as changes in customer behavior or business operations are not considered. Rates could potentially have employment impacts through investment or respending effects but both components are likely to be insignificant and would offset one another (economic modeling, which would be required to estimate potential employment impacts, was not undertaken for this planning exercise).

In summary, the rate options included in the inven-tory add capacity over a range of costs, but result in increased overall energy use. The intra-class rate options defined in the Plan were designed to be revenue neutral as the distribution of the revenues received will change but the total revenue collected by BC Hydro will not. There are no identifiable direct environmental, social/community or employment impacts associated with rates.

30 BC Hydro. *Intra-class Rate Design Options*, February 1995.
31 Refer to Appendix E for a discussion of these and other rate designs.

Table 5.6:

Transmission Options

TRANSMISSION RESOURCE CATEGORY	TRANSMISSION OPTION
Transmission lines	*Arnott-VIT High Voltage Direct Current System Replacement *Arnott to Sahtlam 230 kV Transmission *Malaspina to Dunsmuir 7th 500 kV Cable Nicola-Ruby Creek 500 kV line Second Kelly Lake-Cheekye 500 kV Line (5L86) Second Nicola-Meridian 500 kV Line (5L83)
Stations and Voltage Control Equipment	65 percent Series Compensation (Kelly Lake-Nicola) American Creek Series Capacitors — thermal rating increase Increased Series Compensation on existing Interior to LM lines (FACTS)[32] Mechanically Switched Shunt Capacitors:proposed installation at existing stations in the Lower Mainland Ruby Creek Switching Station
Distribution automation	*Distribution Automation:Automatic control functions for load management on Vancouver Island

*Note: These resource options are designed for reinforcement of supply to Vancouver Island

DISTRIBUTION AUTOMATION:

Automatic control of distribution voltage and VAR levels to regulate load, conserve energy and reduce peak demand.

5.4.10 Transmission

Characterization of the transmission resources is different from that of the resource types previously discussed. This is due to the differences among the individual transmission options and the associated attribute information. To facilitate the characterization, the options have been grouped into the following general categories: transmission lines, stations (and voltage control equipment) and distribution automation. Some of these options are designed for reinforcement of the interior to the Lower Mainland transmission system and others for the Lower Mainland to Vancouver Island transmission interconnection. The transmission options identified for this Plan are listed in Table 5.6

The choice and mix of transmission options is dependent on the size and location of generation resources identified in the 20-Year Outlook. Therefore, a number of suitable transmission options have been identified. The evaluation and selection of transmission requirements for resource portfolios is discussed in Chapters 6, 7 and 8.

The station options and distribution automation are relatively low cost options compared to transmission line options. For example, the individual station options are estimated to range in cost from $3 million to 20 million and the transmission options are estimated to range from about $100 million to $300 million dollars.[33] The station options typically add smaller increments to power transfer capacity whereas the transmission line options add larger increments to the power transfer capacity.

The station options provide no significant savings in system losses whereas the transmission options can provide considerable loss savings. Also, distribution automation is expected to reduce energy and capacity requirements.

32 FACTS represents the emerging Flexible Alternating Current Transmission System Technology.
33 Before accounting for savings in system line losses.

Neither greenhouse gas nor local air emissions have been attributed to transmission options. The station options are not expected to have any environmental impacts or land requirements. Transmission line options, however, have possible species persistence, terrestrial ecosystems and land use impacts. Specifically the land use impacts for these options range from 80 hectares to 1,150 hectares. These impacts are primarily due to the amount of land to be cleared for rights-of-way.

Because the majority of projects are capital intensive in terms of materials required, the associated construction-related jobs created are expected to be high. For example, each transmission line option is expected to create between 500 to 800 person-years of construction-related employment. The station options and distribution automation also produce construction-related employment ranging from 30 to 120 person-years. However, no significant permanent employment is expected to result from any of the transmission options.

In summary, it is difficult to compare transmission options among one another as they serve different purposes and must be examined within the context of BC Hydro system-wide requirements. For example, capacitor stations can only provide benefits if applied in specific locations. Capital costs vary depending on the physical size, capacity and location of the option. The transmission line options have significant annual electricity loss savings because they allow for a more efficient transfer of electricity.

Environmental impacts vary and depend on the specific resource option, with potential impacts on terrestrial ecosystems and species persistence noted for the transmission line options. Also, construction-related employment estimated for these projects varies, with the transmission line options creating the most employment. Significant permanent employment opportunities are not expected for any of the transmission options.

5.4.11 Overview of Resource Characterization

BC Hydro has the potential to acquire significant amounts of energy and capacity to meet growth in demand. The sources cover a broad range of resource types, including alternative technologies, hydroelectric, thermal (natural gas, wood residue, coal and geothermal), purchases, demand-side management, community energy planning, rates and transmission. Energy availability from the inventory amounts to more than 77,000 GWh/year compared to the identified need of 25,000 GWh/year by the end of the planning period. Available capacity amounts to about 12,000 MW, compared with an identified need of 3,700 MW.

Table 5.7 summarizes the contribution of each resource type to energy and capacity availability. As shown, the largest single energy resource is natural gas generation which by itself could support future needs, assuming gas supply infrastructure is adequate to meet fuel demands. The other major energy resource is hydroelectric. Significant amounts of energy are also available from purchases and demand-side management. The primary capacity resources are natural gas generation and hydroelectric. The potential role of natural gas represents a significant difference to BC Hydro's traditional, hydroelectric resource base and reflects changes in technology, market structure, gas availability and pricing in recent years, as well as public values related to environmental protection.

The inventory of resource options is also diverse with respect to the trade-off attributes. Least cost resources, as measured by economic cost (corporate cost less transfers to government) are a mix of natural gas, hydroelectric and community energy planning. This is not to say that all hydroelectric and all natural gas options are low cost; rather these two resources have a predominance of low cost energy or capacity opportunities. On the other hand, some specific options within wood residue, pur

34 This lack of differentiation indicates that most resource options had little or no impact on species persistence and terrestrial ecosystems.In some ways,this result is comforting:it suggests there are minimal impacts based on the attribute definitions used.However, future planning exercises may redefine the attribute to allow comparisons on the basis of more refined biodiversity indicators (e.g.,incorporating species abundance).

Table 5.7:

Summary of Potential Supply

RESOURCE	SUPPLY Average Annual Energy (GWh)	SUPPLY Dependable Capacity (MW)	UNIT ECONOMIC COST OF FIRM ENERGY AT LOWER MAINLAND (Cents/kWh)
Energy and Capacity			
Alternative Technology	1,160	150	(1995) 8.6 – 22+ (2014) 4 – 16
Hydroelectric Energy			
Resource Smart	700	245	1.2 – 3.2
Augmented Generation	3,265	960	0 – 6.7
New Facilities	11,510	1,650	2.2 – 4.8
subtotal	*15,475*	*2,855*	
Thermal			
Natural Gas	>33,000	4,400	2.2 – 3.3
Wood Residue	3,000	380	2.5 – 6.1
Coal	>1,490	>200	4.5
Geothermal	550	70	not available
subtotal	*38,040*	*5,050*	
Purchases			
Imports	9,600	0	1.7 – 7
Alcan	1,225	140	2.8
Downstream benefits (scenario)	4,900	950	3[1]
subtotal	*15,725*	*1090*	
Demand-side Management	6,900	1,000	0 – 22
Community Energy Planning	400	75	RIM
Capacity Only			
Hydroelectric Capacity	0	>2,000	$32 – 133/kW/yr.
Rates	<0	>440	$0 – 3,200/kW/yr.
Total	***>77,700***	***12,660***	
1995 Plan Requirements	25,000	3,700	

1 Estimated market opportunity value of electricity.

chases and demand-side management offer low cost sources of electricity.

With a few exceptions, there is little to distinguish among resource types based on the attributes of species persistence and terrestrial ecosystems.[34] The exceptions are some hydroelectric energy options (mostly new facilities), the geothermal example and new transmission lines.

The most significant distinction with respect to environmental performance is between fossil fuel-based and other resource types because of the impacts of air emissions. Natural gas and coal-fired generation and purchases (which themselves are assumed to be largely coal, oil or natural gas-based) perform moderate to poor on most air emissions attributes. For example, greenhouse gas emissions range from 350 to 530 tonnes of CO_2 equivalents/GWh; population-weighted local air emissions range up to 144 weighted tonnes/GWh, raising concerns about the cumulative impact of additional emissions in sensitive or stressed airsheds such as the Greater Vancouver Fraser Valley and the Lower Fraser Valley. The upstream air emissions reflect an additional concern of some Consultative Committee members for the potential air, land and water implications of natural gas production and transportation.

Some wood residue options may increase population-weighted local air emissions but, through replacement of incinerators or inefficient boilers, these emissions for some projects may in fact decrease thus improving local air quality. Other resource types are neutral on the emissions attributes.

From the perspective of land use, fossil fuel-based resources perform well, as do demand-side resources (i.e., demand-side management, community energy planning and rates). Land use implications for other resource types vary considerably, suggesting that the choice of specific projects will drive the Plan's overall impact on the land use attribute.

Other social/community concerns not captured in the land use attribute may be important at the project licencing stage. Wood residue and natural gas generating plants are generally located in industrial settings with no additional land requirements. However, noise and safety concerns may arise among local residents related to transporting wood residue. Similarly, the land use attribute may not fully reflect the implications of hydroelectric projects on local recreational opportunities, aesthetic concerns and other infrastructure issues.

Hydroelectric resource (energy and capacity) construction activities are relatively labour-intensive, creating more construction employment than other resource types. However, permanent (operating) employment opportunities are the same or lower than for thermal resources or alternative technologies.

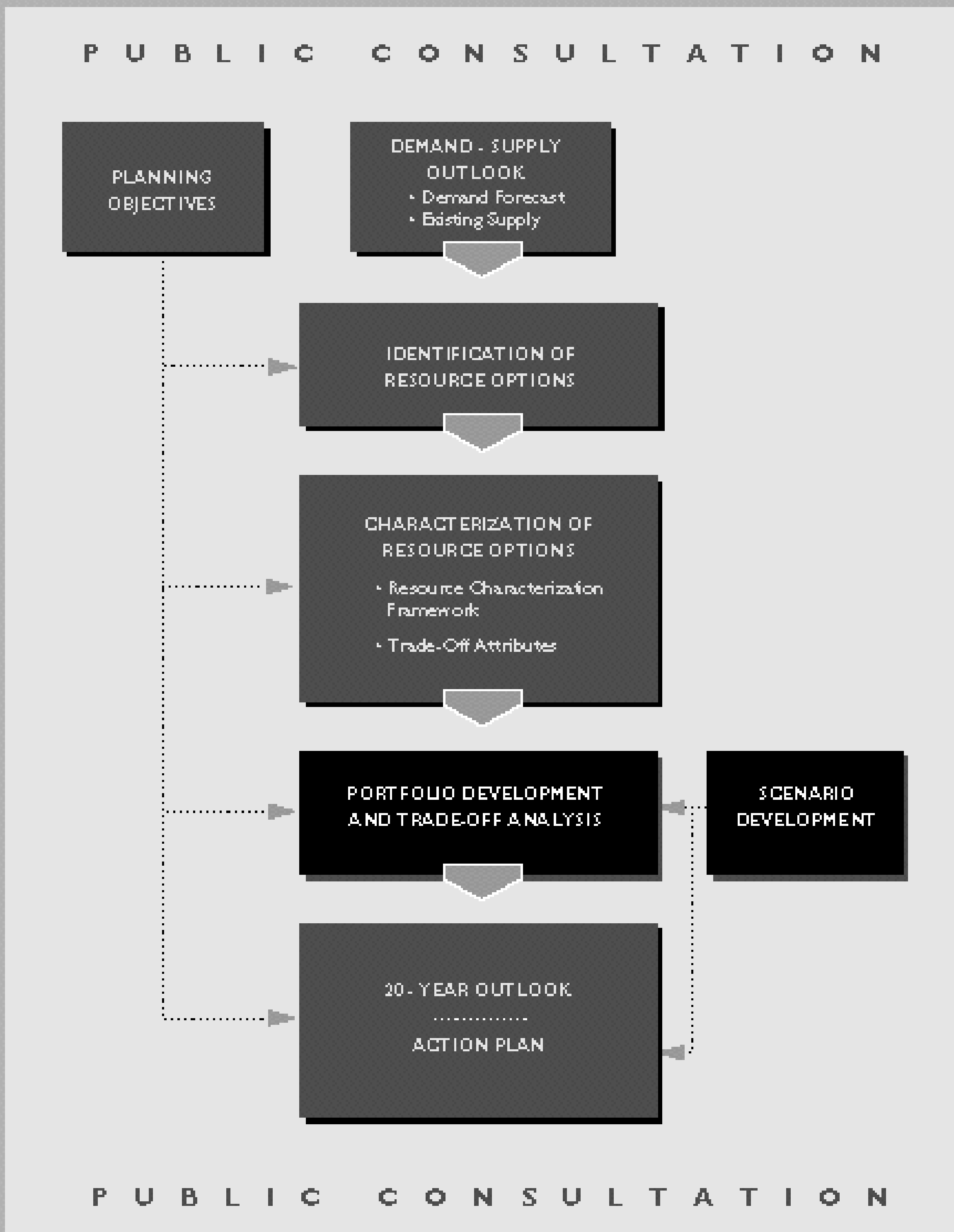
5.5 Summary

The Demand/Supply Outlook (Chapter 3) demonstrated a need to augment the existing electrical system. Drawing from an inventory of diverse generation, demand and transmission resources, BC Hydro has considerable energy and capacity options to meet forecast demand. The choice of appropriate resource options for the Plan is guided by the objectives outlined in Chapter 4. For the Plan, the contribution of any mix of resources to those objectives is measured by 12 attributes, based on the comprehensive Resource Characterization Framework. These trade-off attributes provide a common set of criteria upon which all resource options may be consistently evaluated.

In applying these attributes to the different resource types in the inventory, several general observations surface. First, hydroelectric and natural gas-fired generation are the largest and most cost-effective resource types. Second, the main distinction between these two resource types is the contribution of natural gas generation to increased (greenhouse and local) air emissions, although other differences exist. Third, wood waste, alternative technologies and demand-side resources all perform well on environmental attributes, but may have negative impacts on costs and/or rates.

The range of resource options and their characteristics present opportunities and challenges in selecting resources for an overall Plan. The range in performance on different attributes, even within a resource type, underscore the importance of including data on individual resource options as documented in the Resource Summaries (Appendix E). The development and evaluation of possible resource portfolios based on the inventory, the trade-off attributes and on characterization of individual resource options is presented in the following chapters.

CHAPTER 6
PORTFOLIO DEVELOPMENT AND EVALUATION



6 PORTFOLIO DEVELOPMENT AND EVALUATION

6.1 Introduction

The previous chapter identified potential options available to BC Hydro to serve the electricity needs of its customers. These options were then systematically characterized according to a set of attributes.

In this chapter, individual resource options are grouped into portfolios and evaluated in the context of the BC Hydro system to determine the preferred portfolio for BC Hydro's 20-Year Outlook. A multi-attribute trade-off process, carried out with both BC Hydro managers and the Consultative Committee, established the structure for this evaluation. The most attractive portfolios emerging from the evaluation were subjected to sensitivity analyses using scenarios to test the robustness of the portfolios to changes in the basic assumptions of the evaluation.

The following sections discuss the rationale for portfolio evaluation and the multi-attribute trade-off analysis and then provide details on the steps leading to the establishment of the 20-Year Outlook and Four-Year Action Plan.

6.2 Background

A 'portfolio' is a collection of options chosen from the resource inventory to meet the 20-year forecast demand for electricity services. Several portfolios were developed to address planning objectives and stakeholder interests. The portfolios were analyzed, evaluated, revised and compared to one other – a process which covered some five months in the development of this Plan.

The portfolio evaluation approach was adopted for the Plan, over simply ranking individual options and selecting those with the highest rank. While more complex and time consuming, the portfolio evaluation approach enabled valid comparisons of resource options within the context of the BC Hydro electric system. For example, the portfolio approach allowed evaluation of a diversity of options by examining how they would be dispatched, how they would contribute to the capacity balance, how they would contribute to firm and non-firm energy and how they would interact with each other to meet system demand. Moreover, some attributes – such as diversity – could not be evaluated for individual options.

Portfolios were characterized according to the trade-off attributes described in Chapter 5. As individual resource options were assembled into a portfolio, the characteristics of the options, measured by the trade-off attributes, were combined to produce an overall value for the portfolio for each attribute. For some attributes, this was accomplished by simply summing the contribution of the individual resource option to each attribute. For others, such as greenhouse gas emissions, which depend on resource utilization, the dispatch over the 20-year period was first determined, the attribute values then calculated and the results summed over all resource options.

The portfolio approach provided an explicit and transparent demonstration of the decisions on the choice and timing of options included in the 20-Year Outlook and Four-Year Action Plan.

6.3 Multi-Attribute Trade-off Analysis

6.3.1 Process and Objectives of the Trade-Off Analysis

A multi-attribute trade-off process provided the structure for portfolio development and evaluation. This type of analysis includes elements, reflected in the objectives shown below, which enable meaningful participation by both internal and external stakeholders.

OBJECTIVES OF THE MULTI-ATTRIBUTE TRADE-OFF ANALYSIS WERE:

- *To provide and display information on trade-offs;*
- *To screen out options seen to be 'losers' and highlight potential 'winners';*
- *To make value judgments easier and more consistent;*
- *To communicate the priorities of different groups and to facilitate understanding of opposing viewpoints in the search for agreement;*
- *To show the implications of uncertainty; and*
- *To document the assumptions as well as the link between assumptions and results.*

Two parallel processes of portfolio development, evaluation and trade-off analysis were conducted: one with a group of BC Hydro managers and the other with the Consultative Committee. The process conducted with the BC Hydro managers started in May, lagging behind that of the Consultative Committee, which began in late March.

Some members of the Consultative Committee questioned the need for a multi-attribute trade-off process, suggesting that each sector represented on the Consultative Committee could develop a portfolio and negotiate their interests with other members. To a large extent, this is what occurred within the framework of the trade-off analysis and portfolio evaluations. Consultative Committee members developed their portfolios, which were then analyzed. The data from the analysis provided the basis for discussion among Consultative Committee members. Without the results of the analysis, the Consultative Committee would not have had the financial, technical, environmental, social/community or economic development information with which to enter into discussion or negotiation. Therefore, the trade-off process facilitated group discussion. That said, some members of the Consultative Committee, while interested in exploring the extent to which agreement could be reached, were not interested in negotiating.

BC Hydro retained International Development and Energy Associates (IDEA, Inc.) to assist in the development and implementation of the portfolio evaluation and trade-off analysis. IDEA's report, which provides in-depth coverage of the process and results, is included in Appendix F.

6.3.2 Trade-Off Graphs

The trade-off attributes described in Section 5.3 provided the criteria for the trade-off analysis and portfolio evaluation. Trade-off graphs were used as tools to compare portfolios, by showing their performance two attributes at a time. Figure 6.1 shows a schematic trade-off graph. The system cost attribute is commonly shown on the vertical axis relative to another attribute on the horizontal axis.

The graph is divided into quadrants defined by the performance of a reference portfolio. The Reference Portfolio used in development of the Plan is described in Section 6.4. Portfolios that fall into quadrant 1 – the upper right of the graph – perform poorly on both attributes relative to the reference case and are referred to as 'lose-lose'[1]. On the other hand, portfolios that fall into quadrant 3 – the lower left of the graph – perform better on both attributes than the reference case and are referred to as 'win-win'. Portfolios that fall into quadrants 2 and 4 are those that require trade-offs. That is, an improvement in one attribute can only be achieved with poorer performance in the other attribute.

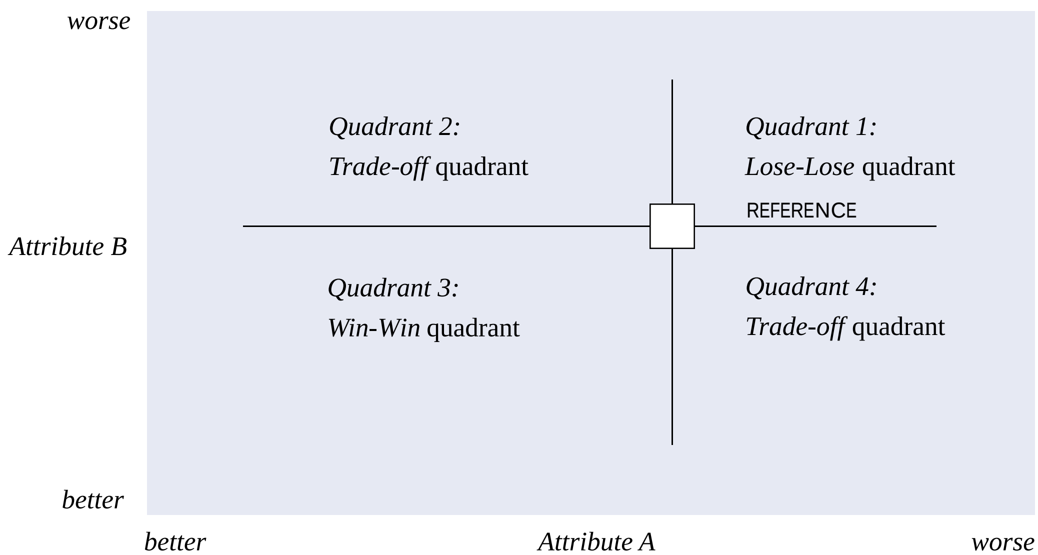
6.3.3 Determination and Use of Weights

As part of the trade-off analysis, weights were assigned to the trade-off attributes by individual members of the BC Hydro managers group and the Consultative Committee. These weights reflect the relative importance of the trade-off attributes and are an expression of the values held by the individuals and the constituents they represent. Individuals were given several opportunities to revise their weights throughout the process, as they gained a better understanding of some of the technical issues and had the opportunity to hear the viewpoints of others.

1 Just because a portfolio falls into the 'lose-lose' quadrant on one trade-off graph does not mean it will be 'lose-lose' in other comparisons.

Figure 6.1:

Schematic of a Trade-Off Graph



The weights were amalgamated[2] with the attribute values to produce overall rankings of portfolios for individual participants in the trade-off process. No attempt was made to 'average' the weights or to strive for a single set of weights from either the BC Hydro managers group or the Consultative Committee. This was to ensure that the trade-off process would recognize differences in individuals' values.

The multi-attribute trade-off analysis was implemented to facilitate an understanding of the trade-offs being made – to inform the decision-making process, not to make decisions in a mechanistic fashion. The trade-off analysis showed how and why differences in values led to different resource and portfolio choices and was successful in identifying the elements of a portfolio on which agreement could be reached, regardless of underlying differences in weights and values.

2 Amalgamation is discussed in Appendix F.

6.4 Portfolio Development

6.4.1 The Reference Portfolio

The Reference Portfolio was the starting point for the portfolio evaluation and trade-off analysis. It served as the basis for comparison of other portfolios developed for the Plan and, as mentioned in the preceding section, constituted the first point on a trade-off graph. The Reference Portfolio held no other special significance other than to provide a useful benchmark against which to compare and evaluate options.

The Reference Portfolio was created primarily from elements of BC Hydro's *1994 Electricity Plan* and was updated in May 1995 to reflect market information on a variety of private sector projects offered in response to the December 1994 Request for Proposals. The composition of the Reference Portfolio is illustrated in Figure 6.2. Only the capacity additions are shown; the capacity of the existing BC Hydro system is not included.

The Reference Portfolio includes the Burrard Upgrade Project, installation of additional generating units at existing BC Hydro facilities at Revelstoke, Mica and Seven Mile dams, replacement of the powerplant at the existing Stave Falls dam, implementation of the *Draft 1995 Demand-Side Management Plan* and the Alcan purchase agreement.

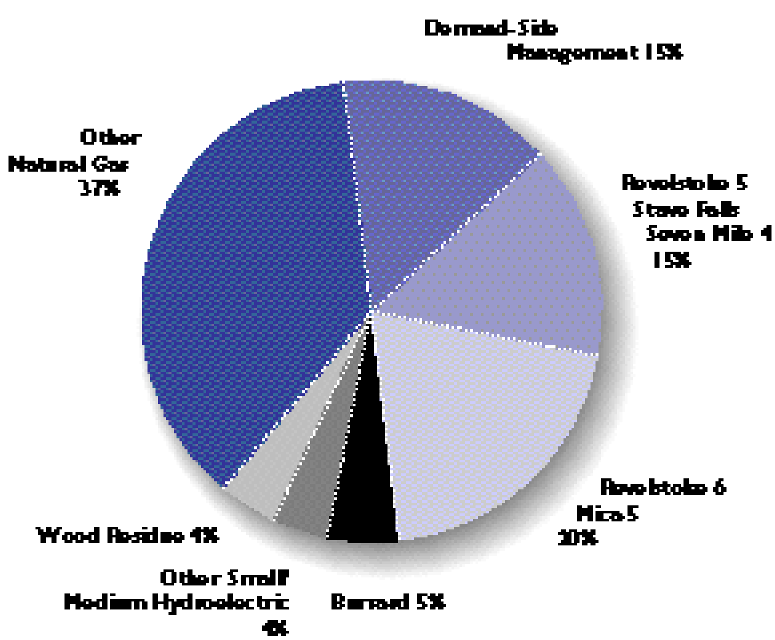
The areas shown as "Other Natural Gas," "Wood Residue" and "Other Small/Medium Hydroelectric" comprise a variety of private sector projects. These projects represent potential options with a range of financial, technical, environmental, social/community and economic development characteristics. They were brought into the Reference Portfolio in order of least economic cost as defined by the system cost trade-off attribute.

6.4.2 Resource Screening Using Trade-off Graphs

The first application of the Reference Portfolio was as a basis for the preliminary screening of resource options. With well over one hundred diverse options available to serve British Columbia's electricity needs, a preliminary screening was necessary to identify the options of greatest interest to BC Hydro and the Consultative Committee while not excluding other options from further consideration.

The approach used was to start with the Reference Portfolio and remove from it, or add to it, individual resource options, one at a time. Selected trade-off graphs were then used to examine the impacts and come to conclusions about obvious 'losers' – whose addition placed the portfolio in the 'lose-lose' quadrant for several attributes – that might be excluded from further consideration. Similarly, potential 'winners' – whose addition placed the portfolio in the 'win-win' quadrant – were identified.

Figure 6.2:
Composition of the Reference Portfolio



Initially some options which were viewed as unlikely candidates for inclusion in the Plan were examined. These included options such as ocean wave technology, the large hydroelectric development at Site C on the Peace River, and conventional coal plants. The trade-off analysis verified that these were less attractive options even when optimistic assumptions, for example, on the future cost of ocean wave technology were made. Such options were thus screened out. Nevertheless, this preliminary screening was not deemed to be absolute and options which had initially been screened out could be re-examined later in the process. This was the case for coal plants, which were re-examined in the first round of portfolio analysis, in one portfolio developed by a Consultative Committee member and another developed by a BC Hydro manager. The re-examination of trade-offs incorporated one of the advanced coal technologies which could be commercially available after 2000.

Next, the robustness of the Reference Portfolio was tested by removing, one at a time, BC Hydro's hydroelectric resources. This analysis showed that removing Revelstoke Units 5 or 6, Mica 5, Seven Mile 4 or Stave Falls moved the Reference Portfolio into the 'lose-lose' quadrant for most attributes. In other words, these resources were best left in the Reference Portfolio.

These types of resource screening demonstrations were used as 'trial runs' of the trade-off process to familiarize both the BC Hydro managers group and the Consultative Committee with the process. The screening also served to illustrate some of the basic trade-offs that would be encountered later in the evaluation of portfolios, and to assist both groups in developing and evaluating their own portfolios.

6.4.3 Portfolio Modeling Tools

To assist with the analysis of portfolios and integrate the portfolio evaluation and multi-attribute trade-off analysis processes, a computer model developed by IDEA, Inc. for the World Bank Environment Department was used. The model, called ENVIROPLAN, was designed to accommodate multiple objectives in utility planning[3]. The model allows the portfolio builder the freedom to specify the types of resources to be included in a portfolio and, if required, complete the portfolio according to objectives specified by the portfolio builder. With the many interests and objectives to be satisfied and traded off against each other in the development of a long-term electricity plan however, decisions and optimization were rarely left solely to the model. For some portfolios, where the builder specified all details, the model was left simply to perform the arithmetic and calculate and display the impacts.

To provide assurance that the model was correctly simulating the BC Hydro system, ENVIROPLAN was calibrated against two of BC Hydro's models: the Resource Planning Model and the Corporate Financial Model. Parallel runs of the BC Hydro models were completed periodically throughout the process to confirm ENVIROPLAN results and, at the end of the process, to confirm the system cost and rate impacts for the final portfolios.

Analytical results for the portfolios were presented in graphical format – the trade-off graphs discussed earlier are one example. Three sets of graphical presentations were used extensively in the portfolio evaluations. These are shown as Figures 6.3 through 6.5. Figure 6.3 is a general overview of an analysis of the Reference Portfolio. Table 6.1 describes the information provided, moving clockwise from the upper left.

Figure 6.4 is an overview of a portfolio's air emissions, shown here for the Reference Portfolio. Greenhouse gas emissions, particulate emissions and emissions of nitrogen oxides (NOx) are shown by year, for each resource type, including imports and exports[4]. Population-weighted

3 Details on ENVIROPLAN are provided in the IDEA,Inc. report.
4 A corresponding chart for sulphur oxides was not included as these emissions were insignificant compared to nitrogen oxides and particulate emissions.Coal and oil-fired thermal resources are the major contributors to emissions of sulphur oxides and these resource options did not figure prominently in the portfolio evaluations.

Table 6.1:

Information Presented on Figure 6.3

ITEM	DESCRIPTION
Capacity Additions	The megawatts added in each year of the planning period are shown, by resource type.
2014 Resource Mix	The composition of the portfolio in the final year of the planning period is shown, by resource type, and compared to the Reference Portfolio. As this output is for an analysis of the Reference Portfolio, both column graphics are the same.
Portfolio Description	A brief description of the portfolio is provided in a text box.
Attribute Values	The impact of the portfolio, measured for each of the trade-off attributes, is given numerically in this table. For comparison, the corresponding attribute values are given for the Reference Portfolio. The minimum and maximum values for a group of portfolios examined at the same time are also provided for comparison. In the lower part of the table, a number of other criteria are shown for information purposes. These are not trade-off attributes, but were included in the table to address the interests of some members of the Consultative Committee in these data.
Attribute Profile	This is a graphical display of the numerical values in the Attribute Values table. The attribute values for the portfolio, normalized relative to the Reference Portfolio, are shown as small squares for each trade-off attribute. The lines indicate the range of normalized attribute values within the group of portfolios examined at the same time. This allows easy visualization of portfolio performance on each attribute, relative to other portfolios. The numerical values have been calculated so that when a portfolio performs better than the Reference Portfolio on a given attribute, the point plots below the zero line on the attribute profile. Similarly, when a portfolio performs poorer than the Reference Portfolio on a given attribute, the point plots above the zero line. Since the Reference Portfolio is the basis for comparison, it plots along the zero line for all attributes.
Generation by Resource	This graphic shows the energy contribution of various resource types for each year in the planning period. Note that the energy capability of the existing BC Hydro system and energy obtained through the Alcan Purchase Agreement are not included.

local air emissions are similarly shown. Both nitrogen oxides and particulate emissions are components of the population-weighted local air emissions attribute, discussed in Chapter 5 of this Plan.

Figure 6.5 is a collection of information, shown here for the Reference Portfolio. Table 6.2 describes the information provided, moving clockwise from the upper left.

ENVIROPLAN is one of a number of computer programs used for technical analysis in utility planning. In fact, BC Hydro has been using computer models in its planning for many years. Although the results of this analysis were to be the focus of the consultation, some stakeholders expressed concern over their lack of knowledge of how the model worked. Individual interviews held with members of the Consultative Committee were intended to provide the opportunity for questions on the process, the model, determination of weights and the analytical results. Still, most questions asked during the interviews related more to data and input assumptions than to the detailed workings of the model.

Figure 6.3:

Enviroplan Output: Overview of the Reference Portfolio

Figure 6.4:

Enviroplan Output: Overview of Air Emissions for the Reference Portfolio

Figure 6.5

Enviroplan Output: General Information for the Reference Portfolio

Table 6.2:

Information Presented in Figure 6.5

ITEM	DESCRIPTION
Generation Balance	In addition to the energy contribution from hydroelectric resources,non-hydroelectric resources,and imports,the forecast demand to be served over the planning period is shown.
Cost Structure	This is a breakdown of cost components,expressed in present value terms.The costs shown include BC Hydro construction costs,other BC Hydro costs, IPP costs,DSM participant costs,and transfers to government.The cost of air emissions,if they were monetized at the values given in the 1994 Resource Acquisition Policy, is also shown. Of these components,transfers and monetized air emissions are excluded from the system cost trade-off attribute.
System Cost Structure	This table provides the numerical values,in present value (PV) terms, for the Cost Structure graphic. A comparison to the values for the Reference Portfolio is provided.
Net Exports	This graphic shows the expected net exports (exports less imports) for each year in the planning period.Negative values indicate net imports.A comparison with the Reference Portfolio is provided.
Tariff Profile	This graphic shows a profile of the tariff (averaged across all customer classes) for the planning period.The values shown are in mills per kilowatt-hour, net of inflation.A comparison with the Reference Profile is provided.

6.4.4 Portfolio Building

During the months of May through July, the BC Hydro managers group and Consultative Committee were engaged in constructing portfolios and examining the implications of various resource choices. To assist them in building portfolios, individuals were first given an inventory of resource options and the yearly capacity and energy increments to be met. Some individuals chose to specify the details of all resource additions, including timing, based on their own judgment and interests. Others identified only themes and objectives, leaving the timing and specifics of additions to BC Hydro.

FIRST ROUND OF PORTFOLIO BUILDING

In its first round of portfolio building, the Consultative Committee put forward 23 portfolios for analysis and the BC Hydro managers group put forward 13 portfolios. These two sets of first round portfolios were similar in many respects. Resources such as community energy planning, alternative technologies and East Kootenay coal appeared in some portfolios in both sets. Afull range of demand-side management options were examined in both sets of portfolios, from exclusion of all demand-side management to exploitation of the full achievable potential identified in the Conservation Potential Review Phase II. Some participants in both groups expressed an interest in acquiring wood residue-fired projects early in the planning period, in seeing a portfolio that would have low cost and rate impact and in limiting dependence on non-renewable natural resources.

As the portfolio building process evolved, the complexities of assembling a complete portfolio while accommodating multiple resource choice constraints became clear. Many portfolios proposed by members of the Consultative Committee were significantly short of capacity, energy, or both. Individual meetings were held with Consultative Committee members to discuss the portfolios and explain the constraints. These meetings gave Consultative Committee members insight into the most effective way to modify their initial portfolios to address any gaps in a manner which was consistent with the underlying themes of their resource selections. Details

Figure 6.6:

Weights Assigned by the BC Hydro Managers

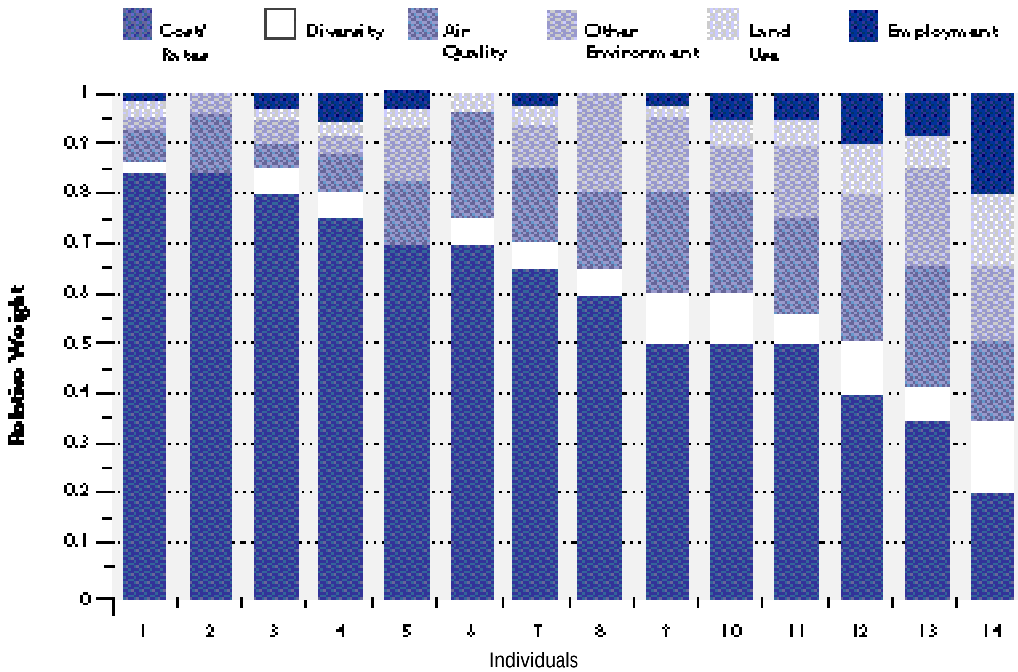
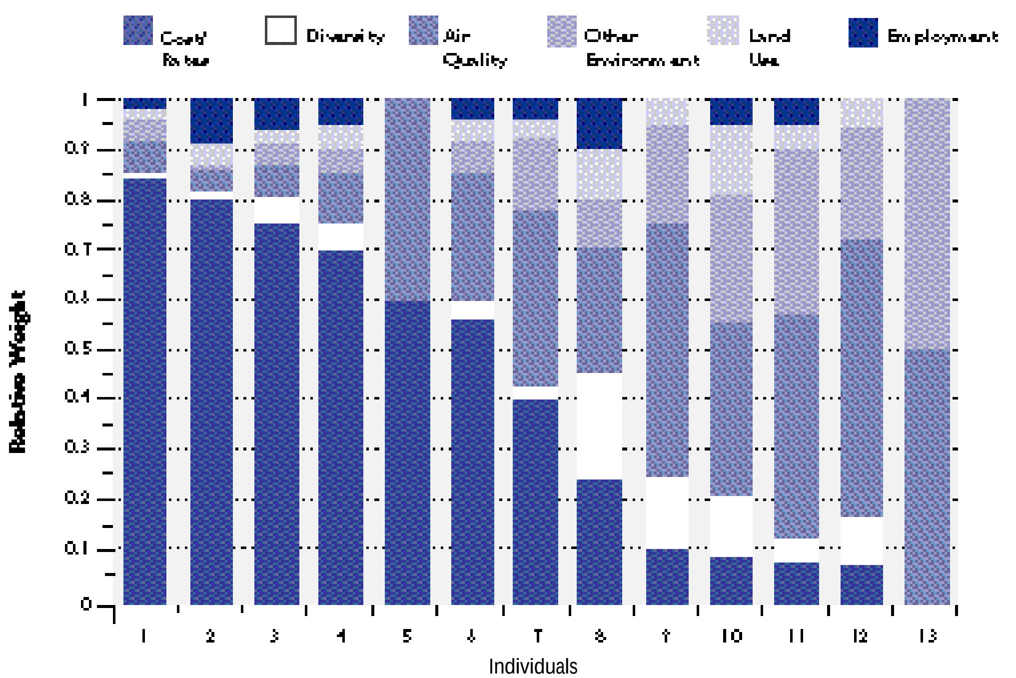


Figure 6.7:

Weights Assigned by the Consultative Committee



of the trade-off process and the development and assignment of weights to the trade-off attributes were also explained.

ELICITATION AND APPLICATION OF WEIGHTS

As discussed above, weights were assigned to the trade-off attributes by individual members of the BC Hydro managers group and the Consultative Committee. An initial set of weights was elicited from both groups at the time the first round portfolios were developed and evaluated. This gave stakeholders the opportunity to see the ranges in attribute values among a number of portfolios prior to assigning weights to the attributes. For example, if the analysis showed there was little difference between portfolios for a particular attribute, or if the attribute values were uniformly low across all portfolios, an individual could choose to assign a lower weight to that attribute. That is not to say the attribute is not important to that individual; rather, that regardless of the weight assigned, there would be little to distinguish among portfolios based on that attribute.

Individuals were given several opportunities to adjust their weights. Interviews were held with individual members of the Consultative Committee to discuss their weights and modify them to better reflect their preferences. This was to ensure that the weights, when applied, would produce results consistent with the trade-offs the individuals would actually be willing to make.

Figures 6.6 and 6.7 show the final set of weights of individual members of the BC Hydro managers group (14 individuals) and Consultative Committee (13 individuals) respectively. These figures show a wide variation in weights among individuals in both groups. Although the BC Hydro managers generally assigned a higher weight to cost and rate factors than the Consultative Committee, there is still a wide diversity in the weights among the BC Hydro group. In the Consultative Committee, the diversity is reflected by one individual who assigned 85 percent of total weight to cost factors and another who assigned zero weight to cost factors.

The weights elicited from both groups were applied to portfolios to better understand stakeholders' views on several key issues – such as Burrard repowering and demand-side management – discussed later in this chapter. As mentioned earlier, no attempt was made to derive a single, or average, set of weights. The weights provided BC Hydro with the opportunity to understand its stakeholders' concerns and preferences and to take these into consideration in its decisions. They were also used to examine the extent of agreement on the final portfolios and BC Hydro's 20-Year Outlook discussed in Chapter 7. Full discussion of the elicitation and application of weights is contained in the IDEA, Inc. report.

The weights developed through this process were for the attributes and portfolios examined in this Plan. They were appropriate for long-range planning, although the same weights and attributes will not necessarily be used in future electricity plans. The same weights and attributes may not be appropriate for project level decisions, however, and are not intended for use in future resource acquisition decisions.

SECOND ROUND OF PORTFOLIO BUILDING

At its meeting in late June, the Consultative Committee sought to consolidate its 23 portfolios and reach agreement on a smaller number of portfolios which still reflected their interests. Members worked in small groups and developed five portfolios for a second round of analysis. Of these five portfolios, two gave preference to early wood residue and small/medium hydroelectric projects, exploring at the same time, the impacts of high and low levels of demand-side management. A third portfolio reflected the interests of low cost and rate impacts. The fourth and fifth portfolios featured sustainability and environmental interests, including a high proportion of renewable resources and alternative technologies.

Some of these portfolios attempted to deal with the constraints revealed in the first round of portfolio building. For example, the fourth and fifth portfolios were proposed to minimize environmental implications. Two portfolios were put forward, in part because of the interest in minimizing fossil fuel generation, while at the same time, avoiding the need for new transmission lines could not be met without significant dependence on imports. To avoid 'exporting' environmental responsibilities, the fourth portfolio met capacity and energy requirements from primarily hydroelectric domestic resources, but minimized fossil fuel use. This portfolio increased the generating capability in the south interior to the extent that development of a second transmission line from Nicola (near Merritt) to Meridian (in Coquitlam) was required to transmit power to the load centres in the Lower Mainland and Vancouver Island. The fifth portfolio avoided the transmission line, but required reliance on some natural gas-fired generation. These portfolios allowed the trade-offs between potential transmission line impacts and air emissions to be examined more closely.

6.4.5 Issues Arising During Portfolio Development

NATURE OF ISSUES

A number of issues were highlighted during the first two rounds of portfolio development. Many of these issues centred on specific types of resource options and some arose from the importance stakeholders placed on a sustainable energy future and the trade-offs required to achieve such a future; others were a comment on the process or other constraints. The issues were discussed at length in an effort to better understand the impacts of certain resource types on portfolio performance, and to try and reach agreement on the make-up of a portfolio to recommend to BC Hydro. Because of strongly held interests in sometimes conflicting objectives however, the Consultative Committee did not always reach consensus on each issue.

The BC Hydro managers group debated the same issues. Their recommendations and decisions on the issues are reflected in the 20-Year Outlook described in Chapter 7.

EARLY WOOD RESIDUE

As noted in Section 5.4.5, the opportunity to use wood residue for electricity generation has gained increased attention since the Province issued regulations which would end open burning of wood residue in a staged process beginning in 1996. Since these regulations would require mills in British Columbia to find other means of disposal of the wood residue, such as high-efficiency incinerators, there appeared to be a limited 'window of opportunity' for the development of cogeneration projects or stand-alone generating stations fired by wood residue.

Advancing the selection of wood residue projects over other resource options[5] was seen by many as an opportunity to assist in the solution to a provincial environmental problem, to improve local air quality and to stimulate regional economic development in the communities where the projects would be located. However, concerns such as those shown in Table 6.3 prevented the Consultative Committee from reaching agreement on advancing wood residue projects. The reasons for advancing wood residue projects are also shown in Table 6.3.

There was also discussion on the availability of wood residue projects after 2000, since legislation requires disposal to be addressed in the coming year. The validity of including these options in portfolios if they were assumed to be acquired later in the planning period was questioned. Wood residue incinerators have a life expectancy of approximately 15 years, therefore any incinerators built in the near future would be due for replacement some time after 2010. This means another window of opportunity for electricity generation using wood residue may open up toward the end of the planning period. Consequently, the wood residue options were left available to the analysis as examples of the range of options and associated impacts which may be available in future.

5 Unless otherwise specified, resource options were brought into portfolios in order of economic cost as defined by the system cost attribute.

Table 6.3:
Issues Associated with Advancing Wood Residue Projects

PERCEIVED BENEFITS	CONCERNS
• Provision of assistance to the Province and forestry sector in environmental clean-up. • Improvement in local air quality, notably particulate emissions. • Support of a greenhouse gas management strategy. • Promotion of regional economic development. • Reduced dependence on natural gas: » hedge on gas price risk; » avoid depletion of a non-renewable resource.	• Potential conflict with provincial policy requiring consistent evaluation of all sources of electricity supply. • Uncertainty in magnitude of particulate emission reductions and impacts on human health,particularly increased NOx emissions and secondary PM-10. • Impacts of transporting wood residue to generating stations: » air emissions from diesel engines; » noise and dust; » highway safety; » roadway maintenance. • Foreclosing on alternative uses which may be found for wood residue. • Uncertainty as to sustainable, long-term supply of wood residue.

ALTERNATIVETECHNOLOGIES

As discussed in Section 5.4.2, the cost of alternative technologies is high relative to conventional options. Advancing these resources over others would increase system cost and rates. Consequently, most portfolios did not include these resource options.

Nevertheless, because of the environmental benefits which could be achieved by acquiring alternative technologies over conventional options, a variety of these technologies were retained in at least one portfolio throughout the evaluation process.

AMOUNT OF DEMAND-SIDE MANAGEMENT

The underlying values of members of the Consultative Committee were particularly evident in discussions on demand-side management, where some members strongly opposed any measures which would increase rates while others felt that conservation, a valid end in its own right, could also be induced through slightly higher rates which may result from utility investments in additional demand-side management.

In general, including demand-side management in a portfolio tends to decrease system cost, increase rates in the short term and improve the performance on environmental, social/community and economic development attributes. The extent of trade-offs between the attributes however, depends strongly on the other aspects of the portfolio. The examination of different levels of demand-side management showed that higher levels of demand-side management kept system costs down in the portfolios which contained relatively high-cost alternative technologies. In portfolios based on the addition of resources in order of least economic cost, higher levels of demand-side management displaced lower-cost, conventional resources and the improvement in economic efficiency was not so pronounced.

Community energy planning was included in the category of demand-side options in the portfolio evaluation and trade-off analysis because of its similarities to demand-side management programs; that is, for a given utility expenditure, energy and capacity savings are realized. In the early resource screening examples, community energy planning was shown to be in the ‘win-win’ quadrant for most trade-off attributes and it was, therefore, included in many of the portfolios examined. This was one measure to which all Consultative Committee members agreed, and it forms part of the Consultative Committee’s portfolio recommendation to BC Hydro.

BURRARD REPOWERING

The future of the Burrard Thermal plant was discussed at length by both the BC Hydro managers and Consultative Committee. Options examined for this Plan included: retiring the plant through a staged shutdown of all six existing units; fully upgrading all six existing units with selective catalytic reduction to reduce emissions of nitrogen oxides; and repowering two, three or four units with combined-cycle modules. With current technology, the maximum number of repowered modules that could be accommodated within the existing plant is four.

Early analysis at the resource screening stage showed that retiring the plant was not an attractive option. Through the portfolio evaluation, based on current information, repowering was shown to be more cost-effective and superior to the full upgrade option in almost all environmental and social/community attributes. This result follows in part from the fact that increased capacity and energy capability from Burrard would displace developments at green field sites and would not require bulk transmission reinforcements to serve the high demand in the Lower Mainland. The repowering options comprise the installation of the latest technology of combined-cycle combustion turbines, progressively retiring the existing units as modules are repowered. Moreover, because repowered units would have higher efficiency than the upgraded ones, per unit gas consumption and air emissions would be less. A full discussion of the analytical results measured by the trade-off attributes is contained in Appendix F.

Discussions then focused on the extent of repowering. Key concerns centred on air emissions and a variety of natural gas issues, such as security of fuel supply, susceptibility to price increases and depletion of a non-renewable natural resource. The Consultative Committee agreed that repowering appeared to be an attractive option; however, that agreement depended on the following:

- the results of a full environmental and social costing review; and
- the results of pursuing the questions:
  "Is there sufficient gas available and gas pipeline capacity to supply a repowered Burrard on a firm contract basis at a price that will not result in rate increases that could be avoided if other resource options were pursued?"
  "Can a repowered Burrard meet future air emissions standards for the Lower Mainland?"
  "What are the impacts on possible generation options located on Vancouver Island that could be developed to serve the Island, which could minimize future transmission costs and impacts?"

To limit air emissions and maintain gas consumption at present levels (approximately 50 petajoules per year), a portfolio was constructed which included only two repowered units. This resulted in a plant configuration of two units retired, two units upgraded and two units repowered. At the same time, a portfolio was constructed in which the model was left to choose options on a least cost basis, as defined by the system cost attribute. This resulted in a full repowering of four modules. The final portfolios discussed later in this chapter contained these two configurations for Burrard.

Preliminary analysis indicated that operation of four repowered modules would comply with current air emissions permits, including declining emission limits[6]. However, some Consultative Committee members felt the economics of the project would change if emissions standards were to change in the future. To the extent that action on the repowering options is required over the next four years, the issue of risk and uncertainty on future air emissions requirements is addressed in the Action Plan of Chapter 8. Although the results of this strategic level plan indicate

6 The current permits are tied to a schedule of installation of selective catalytic reduction (SCR) on the existing steam units, resulting in a step-wise reduction in permitted emissions. Before commiting to a repowering option,further detailed studies would be required to determine the level of emissions during a transition stage from the step-wise schedule based on the SCR installations to the orderly implementation of combined-cycle modules and operation of the existing units at the plant. Additional studies would also be required to ascertain the levels of emissions associated with the installation and operation of four repowered modules,but preliminary indications at this planning level indicate that the cur rent permitted levels would be met.

that the repowering options would have cost, rate and some environmental benefits, the analysis is based on current knowledge of emerging technology. The potential cost advantages, higher efficiencies and air emission improvements, together with the issue of availability and cost of natural gas, as discussed in Chapter 7, would require detailed investigation, evaluation and public consultation before specific commitments to any repowering option can be made. The repowering of Burrard would require a Project Approval Certificate under the Environmental Assessment Act. Detailed studies on emissions and other issues would be undertaken in support of an application for a Project Approval Certificate.

Current gas supply and transportation arrangements to Burrard expire in September 1998. BC Hydro is exploring arrangements to secure firm gas supply which will support the strategic importance of Burrard to its system. Preliminary investigations indicate that a new pipeline from Huntingdon to Burrard is likely to be required to support this strategic role. For the portfolio evaluations, fuel supply for Burrard was based on the assumption that assured transportation from the Huntingdon gas market hub would be available. The repowered units were assumed to have dual-fuel capability; that is, they would be able to use liquid fuel in the event of curtailment of gas supplies in periods of extreme winter demand. The gas commodity price at Huntingdon was based on a forecast of market prices which includes a real price escalation of approximately 1.5 percent per year. Details on these assumptions and their impacts on the portfolios are discussed in the changing gas price scenario analysis in Chapter 7.

6.5 The Consultative Committee's Recommended Portfolio

6.5.1 Development of the Final and Recommended Portfolios

Through discussion of the issues noted above and examination of the performance and trade-offs highlighted in the five second-round portfolios, the Consultative Committee, at its July meeting, identified and focused its attention on two final portfolios. The first portfolio, labeled F1, was designed to keep rate impacts to a minimum, incorporating a minimum level of demand-side management and adding new resources in order of least cost, as defined by the system cost attribute. The second portfolio, labeled F2, was designed to achieve environmental benefits and promote a conservation ethic, incorporating as many forms of renewable energy as possible and a high level of demand-side management. These two final portfolios received detailed analysis of transmission requirements and rate impacts and were subjected to sensitivity testing in the scenario analysis described in the following chapter.

After examining their own portfolios, the Consultative Committee's second round of portfolios and the same issues debated by the Consultative Committee, the BC Hydro managers agreed that the Consultative Committee's two final portfolios adequately covered the range of their interests. The analytical results of these final portfolios, along with further discussion by the managers group led to decisions on an outlook for BC Hydro, as discussed in the following chapter.

At its August meeting, the Consultative Committee focused on reaching agreement to the extent possible on a portfolio to recommend to BC Hydro. The outcome, while not a consensus on a single group of resources, is a portfolio with subsets which the Consultative Committee recognized would leave a choice to decision makers. The portfolio recommended to BC Hydro is indicative of the

Table 6.4:

Elements of the Consultative Committee's Recommended Portfolio and Subsets

COMMON ELEMENTS OF PORTFOLIO RECOMMENDATION	
Revelstoke Units 5 and 6	
Stave Falls Powerplant Replacement see note (i) and (ii)	
Seven Mile Unit 4	
Burrard Thermal Plant: Repower up to three modules	
Demand-Side Management: Programs passing ratepayer impact measure (RIM) test	
Community Energy Planning	
Portfolio Subset F1	**Portfolio Subset F2F**
Burrard: repower 4th module, if economic relative to other options.	Burrard: retire remaining units.
Mica 5, if required for capacity.	Alternative technologies, including 550 MW installed capacity of wind, free stream tidal, solar photovoltaic and fuel cell resources.
Other resources (any technology) as required to meet energy and capacity requirements, in least cost order.	Other resources as required to meet energy and capacity requirements, with preference to small and medium hydroelectric projects and Mica Unit 5, if required.
	Maximum DSM, including achievable potential identified in the Conservation Potential Review Phase II.

(i) A majority of Consultative Committee members requested independent verification of the estimated $53 million in avoided costs from retiring the Stave Falls powerplant and wished to ensure there is a forum for addressing environmental questions about the project, particularly its impact on potential rehabilitation of fish habitat in the Alouette River.

(ii) In the analysis underlying the *1995 Integrated Electricity Plan*, the estimated avoided retirement and decommissioning costs have not been credited to the project.

range of values held by the stakeholders represented on the Consultative Committee. The rationale for this recommendation was succinctly put by a member of the Consultative Committee, as follows:

"In addition to a set of 'core resources', [the portfolio] also contains two alternative subsets of resources which reflect two very different ways of looking at our energy future. One of these subsets takes a 'business as usual' approach to energy planning by trying to identify those resources which would cause the least increase in rates. In the absence of other factors, this would clearly be the most sensible approach; after all, a rational consumer will generally prefer to pay less rather than more for any commodity.

The second portfolio subset, on the other hand, is predicated upon the belief that 'business as usual' is rapidly becoming impossible. It recognizes that the threat of global warming has led our governments to make commitments to stabilize or reduce greenhouse gas emissions. It takes note of the loss of life and health which are caused by increases in air pollution and the increasing societal unwillingness to pay that cost. It gives regard to the history of technological change and to the sad fates of those who have continued to rely on outmoded technologies. It looks ahead to the opportunities which new electrical generation technologies could offer to business in British Columbia."

The Consultative Committee's portfolio recommendation, with subsets, is given in Table 6.4. For modeling purposes, the common elements were combined with each subset to form two portfolios: F1 and F2F. When separated in this way, the subsets are similar to the final portfolios; in fact, F1 is unchanged. The development of F2F from F2 reflects the Committee's agreement to repower up to three modules at Burrard. In Portfolio F2F, the remaining units at Burrard are retired. In the remainder of this document, remarks on Portfolios F1 and F2F refer to the two subsets of the Committee's recommended portfolio.

The recommended portfolio and subsets are shown graphically in Figure 6.8. Only the dependable capacity additions are shown; the capacity of the existing BC Hydro system is not included. The installed capacity of the alternative technologies included in portfolio subset F2F is 550 MW; however, the contribution to dependable capacity from these options, shown on Figure 6.8, is 132 MW. F2F also includes approximately 1,000 GWh/year of electricity assumed to come from small and medium hydroelectric resources, beyond what was offered in response to the December 1994 Request for Proposals[7].

ENVIROPLAN output for F1 and F2F are shown on the following pages as Figures 6.9 through 6.14. Table 6.5 summarizes the trade-off attribute values for the portfolios[8].

Table 6.5:

Comparison of Attribute Values for Portfolios F1 and F2F

ATTRIBUTE	F1 VALUE	F2F VALUE
System cost ($billion,present value)	10.6	11.0
Rate Impact (percent change from Reference Portfolio)	-2.1	0.8
Diversity Index	420	1,200
Upstream Air Emissions (million tonnes)	19	11
Greenhouse Gas Emissions (million tonnes)	98	54
Population-weighted Air Emissions (billion person-tonnes)	326	192
Particulate Emissions (tonnes)	471	4,057
Species Persistence (no. species)	3	4
Terrestrial Ecosystems (hectares)	44	349
Land Use (hectares)	742	3,082
Employment (thousand person-years)	12	30

7 The estimated cost of these resources,as shown on the Resource Summaries in Appendix E,was included in the portfolio evaluation;however, no environmental, social/community or economic development attribute values were estimated for these unidentified projects. As a result,employment impacts of the portfolio may be underestimated.Careful siting of these potential projects would minimize other environmental and social/community impacts.

8 A discussion of the EMF attribute follows in Section 6.6.3.

Figure 6.8:

Composition of Consultative Committee's Recommended Portfolio (contribution to dependable capacity)

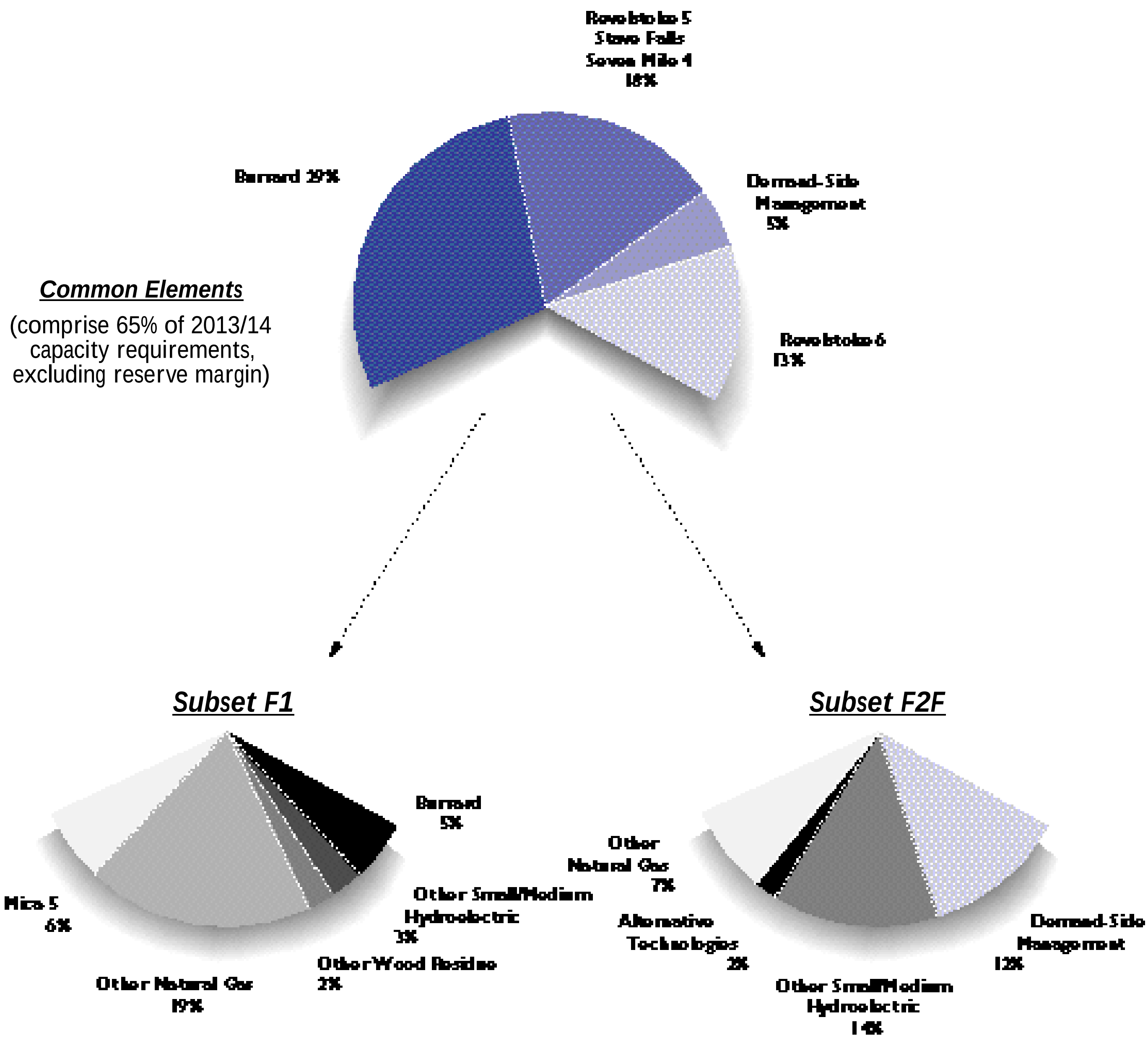


Figure 6.9:

Enviroplan Output-Portfolio F1

Figure 6.10:

Enviroplan Output-Portfolio F1

Figure 6.11:

Enviroplan Output-Portfolio F1

Figure 6.12:

Enviroplan Output-Portfolio F2F

Figure 6.13:

Enviroplan Output-Portfolio F2F

Figure 6.14:

Enviroplan Output-Portfolio F2F

As can be seen from Table 6.5 and the ENVIROPLAN output, Portfolio F1 performs better than F2F on the system cost and rate impact attributes. The present value of system costs in F1 is $365 million lower and the rate impact is almost three percent lower than in F2F. Clearly, the trade-offs between the two portfolios are higher costs for lower air emissions (except for particulate emissions, as discussed in the following section).

The system cost attribute was developed to reflect economic costs measured from a provincial perspective. The attribute, as defined in Chapter 5, includes capital, operating, maintenance and fuel costs for BC Hydro and private sector resources as well as net customer costs[9] for demand-side management programs. These components of the system cost attribute are shown on the system cost structure table in Figures 6.11 and 6.14. When broken out in this way, the present value costs may viewed from several perspectives:

- as defined – indicative of the provincial perspective;
- without customer costs – indicative of the utility's perspective; and
- customer costs alone – indicative of the customers' perspective.

When demand-side management customer costs are included, Portfolio F2F with high demand-side management has a higher system cost than Portfolio F1 with minimum demand-side management. When demand-side management customer costs are excluded – indicative of BC Hydro's, but not society's, costs – the reverse is true, and F2F has a lower system cost than F1.

This shift in portfolio performance as a result of the treatment of demand-side management customer costs was discussed at the September meeting of the Consultative Committee. To enable a comparison of the costs from many perspectives, BC Hydro agreed to continue to provide information on the components of the system cost attribute. In addition to the standard ENVIROPLAN output, a new attribute profile was prepared which decomposes the attribute into its component parts. This graphic is included with the discussion of the Consultative Committee's portfolio recommendation relative to BC Hydro's 20-Year Outlook in Chapter 7.

F2F accomplishes the objective of keeping greenhouse gas emissions stabilized. While increasing from the 1995 level of just under 2 million tonnes[10], greenhouse gas emissions remain below 4 million tonnes per year for most of the planning horizon. In contrast, F1 has almost twice the greenhouse gas emissions by 2014, at over 8 million tonnes per year. F2F performs better than F1 on all air emissions attributes, except particulate emissions. This is a function of the amount of wood residue in the portfolios, as discussed in the following section. F2F is also more diverse than F1, as a result of the higher level of demand-side management and the variety and amount of alternative technologies.

Within Portfolio F2F itself however, there are trade-offs: improvement in air emissions for greater impact in the non-air environmental attributes. The small and medium hydroelectric projects and wind farms contribute to higher land use and area of special zones affected.

Through the respending effects estimated to accompany the high level of demand-side management, F2F creates more employment benefits than F1 which contains mostly supply-side resources.

6.5.2 Resolution of Issues

EARLY WOOD RESIDUE

None of the final portfolios advanced wood residue projects; however, at the request of the Consultative Committee, F1 and F2F were examined with and without the addition of 200 MW of wood residue projects prior to the year 2000.

9 Demand-side management customer costs are net of incentives or rebates.
10 Greenhouse gas emissions from the BC Hydro system vary from year to year, depending primarily on the utilization of the Burrard Thermal plant. Greenhouse gas emissions from Burrard in 1994 were 2.1 million tonnes.

When 200 MW of wood residue projects were added in 1999, the system cost in both portfolios increased by approximately $100 million in present value terms, accompanied by a 0.3 percent rate increase for F1, compared to the Portfolio without early wood residue, and a 0.1 percent rate increase for F2F. The diversity index improved for Portfolio F1 but was lower for F2F as the slightly larger wood residue plants displaced smaller hydroelectric projects; i.e., the number of resource additions in F2F decreased.

When wood residue projects were added to the portfolios, the biggest improvements occurred in the air emissions attributes[11]. It is in these analyses that the extent to which the particulate emissions attribute is dominated by the assumptions on the amount and timing of wood residue projects in any portfolio becomes apparent. This is due to the credits given to wood residue projects for the incremental improvements in particulate emissions which are estimated to occur when wood residue is burned in a power boiler rather than a high-efficiency incinerator. These air emission credits give rise to some seemingly anomalous results. For example, a 'green'portfolio, such as F2F, with no wood residue plants and only minimal particulate emissions from the operation of a repowered Burrard, performed worse on the particulate emissions attribute than Portfolio F1, which had much higher levels of natural gas-fired resources but also included some wood residue plants.

The burning of wood residue is assumed to make no net contribution to greenhouse gas emissions, therefore greenhouse gas emissions were reduced in both portfolios as other thermal resources were displaced or deferred by the wood residue projects. There was little difference in the non-air environmental attributes and no difference in employment for either portfolio.

In Portfolio F1, advancing the wood residue projects deferred the addition of Revelstoke Unit 6 from 2000 to 2007; however, other resources which would provide energy were required by 2002. In Portfolio F2F, the contributions from alternative technologies and high demand-side management, in combination with the early wood residue, were sufficient to defer the need for other resources by approximately five years, with the result that thermal resources which had entered the portfolio in 2013 and 2014 in the case without wood residue projects were deferred beyond the planning period. The final portfolio recommended by the Consultative Committee includes, but does not advance, wood residue.

ALTERNATIVETECHNOLOGIES

Portfolio subset F2F retains 550 installed megawatts of alternative technologies. The Consultative Committee recognized that, since this subset does cost more than the first, it is unlikely to be selected by BC Hydro if resource choices are dictated by market forces. Therefore, an additional series of recommendations was made by a group of Consultative Committee members, as follows:

- *"BC Hydro should undertake activities and implement policies which will enable British Columbia to make a transition to sustainable energy technologies. Technologies which could potentially lead to utility-scale projects should be explored and tested. Private investment in small-scale distributed generation from renewable energy sources should be stimulated through BC Hydro research, incentives and services."*
- *"Comprehensive wind mapping should be undertaken to locate the best available sites in British Columbia. Wind generation technology has become competitive in Alberta and the U.S. Pacific Northwest, but British Columbia lags behind neighbouring jurisdictions in identification of high-quality wind resource sites."*
- *"BC Hydro should emphasize wherever possible the substitution of alternative technologies for diesel generation in remote off-grid service areas. Where diesel generation continues to be used, BC Hydro should consider substituting biomass-derived fuel for fossil-derived diesel fuel."*

11 Air emissions from vehicles used to transport wood residue to the generating plant sites are not included in this analysis,as discussed in the thermal resources characterization in Chapter 5.

- *"BC Hydro should provide information, assistance and alternative energy service options for off-grid residential, agricultural and small commercial customers where line extensions would otherwise be required."*
- *"BC Hydro should improve the economics of private investment in small scale self-generation from solar, wind and micro-hydroelectric sources by providing options such as 'power-banking'; i.e., storage services for intermittent and seasonal sources. Seasonal rates could be bundled with power-banking to compensate for lack of peak coincidence."*

AMOUNT OF DEMAND-SIDE MANAGEMENT

The level of demand-side management differs in the subsets of the Consultative Committee's recommended portfolio. This is a reflection of the diversity of interests represented on the Consultative Committee: the interests of industrial customers who are concerned their competitive positions in the marketplace might be compromised if rates were to increase versus environmental interests who wish to promote a conservation ethic and renewable technologies.

In an effort to display the extent of trade-offs involved, the final portfolios were examined with three levels of demand-side management: a minimum level, representative of programs which would not impact rates; the level of the *Draft 1995 Demand-Side Management Plan* included in the Reference Portfolio; and the maximum level which adds the achievable potential identified in the Conservation Potential Review. When the weights of individual Consultative Committee members were applied to the portfolios with different levels of demand-side management, the minimum level of demand-side management was preferred for F1 and the highest level of demand-side management was preferred for F2F. The portfolio with the uniformly lowest rank was F2F with low demand-side management. This bears out a point made earlier: demand-side management is a beneficial component of a portfolio that contains a significant level of higher-cost resources. Moreover, the portfolios are preferred by the Consultative Committee as specified: F1 with minimum demand-side management and F2F with maximum demand-side management.

The application of the Consultative Committee's weights to the portfolios with different levels of demand-side management is discussed more fully in Appendix F.

BURRARD REPOWERING

Repowering Burrard was one of the issues on which the Consultative Committee reached agreement, with the recommendation that, in the common elements of the portfolio, up to three modules be repowered. In the F1 Portfolio subset which adds resources of any technology on the basis of low cost, the fourth module is repowered. In the F2F Portfolio subset which seeks to minimize environmental impact, the remaining units at Burrard are retired.

When the Consultative Committee members' individual weights were applied to the five Burrard cases (retire, full upgrade, repower 2, 3 and 4 modules), repowering either three or four modules was the first ranked choice for all members – an analytical agreement reflected in the agreement reached by the Consultative Committee on this issue. This analysis is fully developed in Appendix F.

As discussed in the Consultative Committee's deliberations on Burrard, any level of repowering acknowledges that additional investigation would be required before an actual commitment to proceed with repowering could be made.

6.6 Transmission Requirements of the Consultative Committee's Recommended Portfolio and Subsets

6.6.1 Transmission Planning Criteria

In addition to the transmission considerations described in Chapter 3, the bulk transmission system requirements for the final portfolios were determined on the basis of technical viability and economic considerations. Technical viability was assessed in terms of satisfying the transmission planning criteria for adequate system performance and reliability. The transmission planning criteria set by BC Hydro comply with those set by the Western Systems Coordinating Council, of which BC Hydro is a member. The primary criterion followed was that there be no interruption of load or generation due to any single contingency, such as a line or transformer outage, under any stressed condition such as maximum generation in the south interior region or maximum generation in the north at the time of peak load.

The capacity of the transmission system to transmit power was determined using system simulation computer models which evaluate steady-state and dynamic system performance under various contingency conditions. The transfer capacity of the system is limited by the most constraining of voltage stability, dynamic stability or thermal limits.

Once the technically viable transmission options were established, the selection and sequencing of these were based on economic considerations, including the cost of system losses. Details of the transmission analysis are provided in Appendix H.

6.6.2 Assessment of Portfolio Transmission Requirements

The specific type and characteristics, including geographic location, of some of the generation sources shown in Table 6.4 are known (e.g., Mica, Revelstoke). There are 'other resources' shown on that table however, whose type and characteristics, including location, are not known. These other resources are assumed to be private sector projects offered in response to future requests for proposals over the next 20 years. For the purposes of this transmission analysis, for Portfolio F1, 60 percent of the new generation is assumed to be located in the Lower Mainland and Vancouver Island regions and 40 percent in the north and south interior regions. The corresponding percentages for F2F are 45 percent in the Lower Mainland and on Vancouver Island and 55 percent in the north and south interior.

With these assumptions on the location of future generation, the worst-case condition to be met by the Interior to Lower Mainland bulk 500 kV transmission system is an outage of the Nicola to Ingledow line or Nicola to Meridian[12] line when generation in the south interior is at its maximum coincident with winter peak load. This worst-case condition was simulated by assuming all installed and new generation in the south interior operating at 100 percent maximum capacity, Lower Mainland and Vancouver Island generation operating at the dependable winter capacity and the generation planning reserve[13] being held in the northern region.

The resulting transmission requirements are summarized in Table 6.6. In selecting the options, the general strategy adopted was to use low-cost reactive support options, such as mechanically switched capacitors and series capacitors, before adding a new transmission line to meet voltage stability and transient stability limitations, until thermal limits were reached. In fact, no new transmission lines into the Lower Mainland were required in either of the portfolios within the 20-year planning period[14].

12 The Nicola station is near Merritt; Ingledow is in Surrey; and Meridian is in Coquitlam.
13 This is roughly 12 percent of system capacity and corresponds to a loss of load expectancy of one day in ten years.
14 This result is based on the assumptions made in the allocation and timing of new generation resources between the north and south interior, Lower Mainland and Vancouver Island.

Table 6.6:

Transmission Requirements for Portfolios F1 and F2F

ESTIMATED IN-SERVICE DATE	PORTFOLIO F1	PORTFOLIO F2F
1997	100 Mvar mechanically switched shunt capacitors	
1999	Uprating of American Creek series capacitors to 3,000 Amperes	Uprating of American Creek series capacitors to 3,000Amperes
2000	Guichon (5L87) 65 percent series capacitor station Seventh 500 kV Malaspina-Dunsmuir cable	
2002	Conversion of Dunsmuir to Sahtlam line from 230 kV to 500 kV operation	Seventh 500 kV Malaspina-Dunsmuir Cable, Conversion of Dunsmuir to Sahtlam line from 230 kV to 500 kV operation
2005		Guichon (5L87) 65 percent series capacitor station 100 Mvar mechanically switched shunt capacitors
2006	Jingle Pot-Nanaimo 500 kV/230/138 kV substation upgrade including a 500 kV transmission loop from the Dunsmuir-Sahtlam line	Jingle Pot-Nanaimo 500 kV/230/138 kV substation upgrade including a 500 kV transmission loop from the Dunsmuir-Sahtlam line
2009	Series compensation on 500 kV Mica to Nicola lines 100 Mvar mechanically switched shunt capacitors	200 Mvar mechanically switched shunt capacitors
2010	100 Mvar mechanically switched shunt capacitors	
2012		200 Mvar mechanically switched shunt capacitors

Portfolio F1, with a minimum level of demand-side management, has both high net load growth and new generation in the high demand regions of the province; i.e., the Lower Mainland and Vancouver Island. Consequently, the required power transfer capacity of the south interior to Lower Mainland transmission system can be met cost effectively by the addition of 65 percent series compensation on the existing Kelly Lake[15] to Nicola line. The series compensation provides better utilization of the interior to Lower Mainland 500 kV transmission network by improving the sharing of power flow among the four interior to Lower Mainland 500 kV lines, especially during line outages. Addition of a fifth generating unit at Mica in 2009 requires the installation of series capacitor banks to increase the power transfer capability of the Mica to Nicola 500 kV lines.

To supply Vancouver Island, the seventh 500 kV submarine cable (an addition to the existing 500 kV Malaspina to Dunsmuir intertie) was considered to be the preferred economic[16] alternative in the portfolio analysis. This could be required as early as the year 2000. If no new generation is developed on Vancouver Island after the year 2000, the replacement of high voltage direct current (HVDC) Pole 1 could be required as early as 2007, when Pole 2 is retired.

Portfolio F2F has high demand-side management and high incremental generation in the south interior. The surplus south interior generation – surplus to that needed to meet the region's peak demand – is not large enough to require a new transmission line within the 20-year planning period; however, the new Nicola to Meridian line

15 Kelly Lake is near Clinton.
16 The seventh cable alternative is discussed in section 7.2.3.

could be required under certain scenarios[17] such as high demand, that add more generation in the south interior. To supply Vancouver Island, the seventh 500 kV submarine cable is required as early as the year 2002.

6.6.3 Electric and Magnetic Fields Analysis

Although BC Hydro has concluded that there is insufficient scientific evidence of a link between transmission line exposure and adverse health impacts, the analysis of the portfolios included a comparison of magnetic field exposure levels. Only magnetic field (MF) exposure levels in milligauss-persons were assessed since, as stated in Section 5.3, exposure to low frequency electric fields is not considered to pose any health risks.

While the absolute milligauss-person values for the portfolios may be inaccurate, they are adequate to compare the performance of different portfolios on this attribute. The results of the MF exposure studies indicate that there is no significant overall difference in the MF exposure levels among the portfolios[18]. When comparing one portfolio with another, increases in MF exposure levels along some transmission lines are balanced by decreases along other lines.

6.7 Summary

In preparing the 1995 Integrated Electricity Plan, BC Hydro chose a portfolio evaluation approach over simply ranking individual resource options and selecting those with the highest rank for inclusion in the Plan. This approach was taken to demonstrate the impacts of choices on the BC Hydro system as a whole.

The structure for developing and evaluating portfolios was provided by a multi-attribute trade-off process using the attributes and characterization of resource options presented in Chapter 5. This process was designed to show how and why differences in individual values led to different resource and portfolio choices as well as identify those resource options which all stakeholders agreed on. As part of the process, BC Hydro managers and Consultative Committee members developed and evaluated over 40 portfolios. This exercise was instrumental in highlighting the complexities and trade-offs required in meeting capacity and energy demand.

The portfolio development process explored a wide variety of possible mixes of resource options and planning issues. In developing its recommended portfolio, a number of issues were intensively discussed by the Consultative Committee. Some of the key issues included the treatment of wood residue projects, alternative technologies, the amount of demand-side management and repowering of the Burrard Thermal Generating Station.

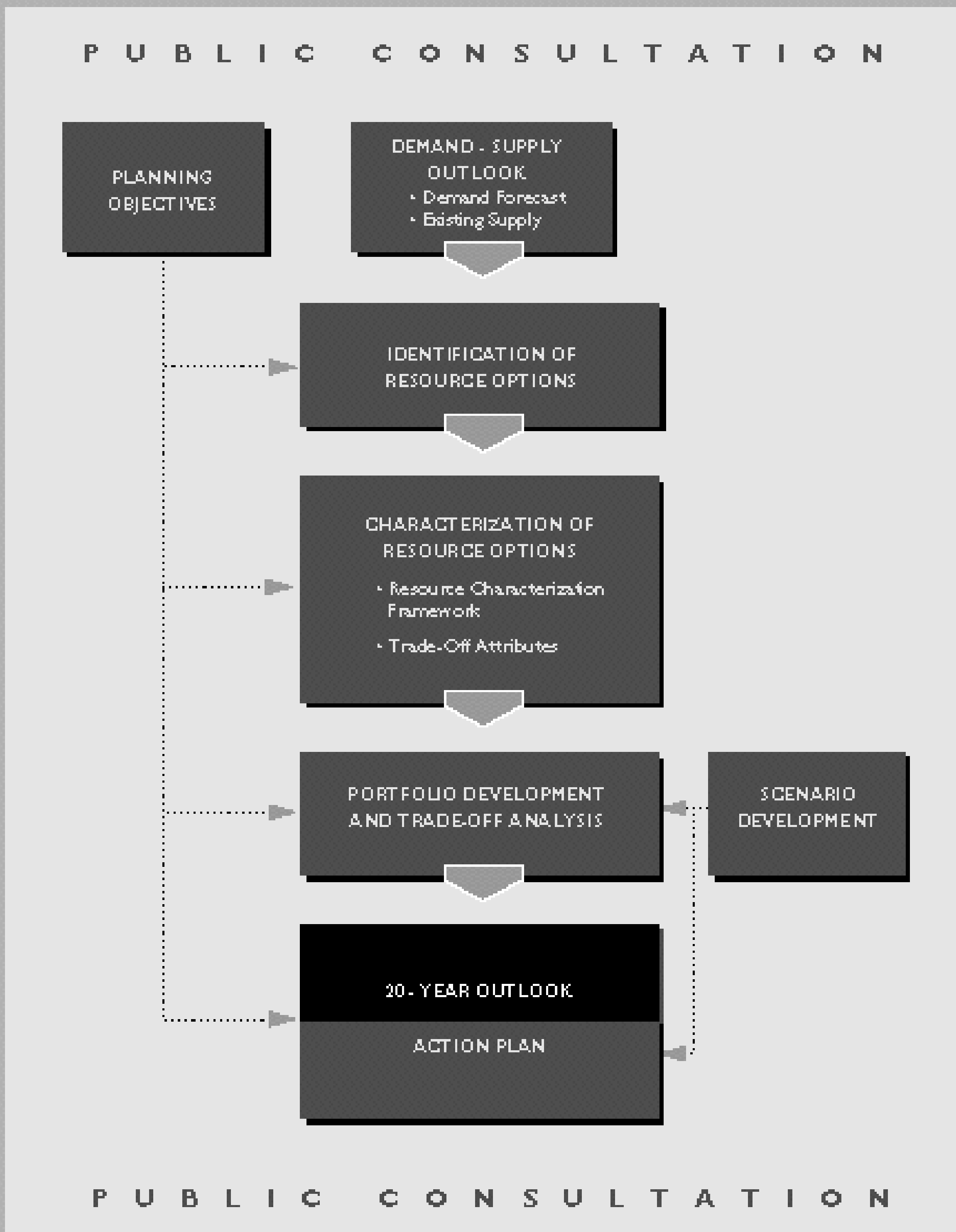
A Consultative Committee portfolio recommendation, with subsets referred to as F1 and F2F, represents the synthesis of five months of evaluation and deliberation. The objectives of Portfolio Subset F1 were to keep costs low and minimize rate impacts. The objectives of Portfolio Subset F2F were to promote a conservation ethic and incorporate a wide variety of renewable energy types for environmental and diversity reasons. Even with these apparently varied aims, a core of resources which meets 65 percent of the capacity and 49 percent of the energy requirements of the Plan was agreed to by all Consultative Committee members. The portfolio, with its subsets, was a consensus recommendation of the Consultative Committee to BC Hydro.

The recommended portfolio subsets received a detailed analysis of transmission requirements; neither subset required new bulk transmission lines into the Lower Mainland. The sensitivity of the portfolio subsets to uncertainties was examined using scenario analysis. The results are discussed in the following chapter.

From the portfolio evaluation process, input from the BC Hydro managers group and recommendations from the Consultative Committee, BC Hydro developed its 20-Year Outlook, which is presented in the following chapter.

17 Scenarios are discussed in Section 7.3.
18 The quantitative analysis indicated less than 5 percent difference between the two portfolios. This difference is well within the margin of error for population and magnetic field estimates.

CHAPTER 7
THE 20-YEAR OUTLOOK



7 The 20-Year Outlook

7.1 Introduction

BC Hydro's 20-Year Outlook presents the current view on options to meet British Columbia's electricity needs, considering Corporate objectives and priorities, the implications of a changing market structure within the electricity industry and the interests expressed by stakeholders. The Outlook was developed within the portfolio evaluation process described in Chapter 6, with the benefit of discussions among the BC Hydro managers group and Consultative Committee and the results of the portfolios examined by both groups.

Developing a 20-Year Outlook does not infer the resource acquisitions set out will be rigidly adhered to. The long-range plan provides a 'snapshot' in time of how the demand and supply pattern may unfold. In the past, a long-range plan was necessary due to the long lead times associated with large hydroelectric projects. With smaller-sized generation plants now cost effective, the lead time for new supply has been reduced. This necessitates changes in planning periods and methods. Although it is important to look out to the future in terms of demand, resource availability and markets in general, future electricity plans will likely have shorter planning horizons.

This chapter presents the 20-Year Outlook and examines its performance under a variety of uncertainties. The Plan is then explicitly linked back, through the attributes, to the planning objectives set out in Chapter 4 by discussing the degree to which the Plan contributes to the objectives.

7.2 The 20-Year Outlook

7.2.1 Composition of the Outlook

The 20-Year Outlook includes additions of demand-side, supply-side and transmission resources. Demand-side and supply-side additions are discussed below; transmission additions are discussed in Section 7.2.3.

7.2.2 Demand-Side and Supply-Side Resources

BC Hydro's 20-Year Outlook, also referred to as the 'BCH' or 'selected'portfolio, adds to the existing system the resource options shown in Table 7.1. The Outlook includes the continuation of plans to replace the powerplant at the Stave Falls dam and to add a fourth generating unit at the Seven Mile dam. The capacity additions at Revelstoke (Units 5 and 6) and Mica (Unit 5) appear in this Plan, as they have in previous electricity plans. The Outlook includes an option to fully repower the Burrard Thermal plant. Repowering would, however, be phased in over time, starting with an upgrade and installation of selective catalytic reduction on a second unit, followed by repowering one module. Repowering of the remaining modules would be staged, recognizing that all repowering options would require detailed investigation, evaluation and public consultation before specific commitments could be made and an application for a Project Approval Certificate submitted.

In addition to these BC Hydro resources, the Outlook includes up to 900 MW of capacity and 8,400 GWh/year of energy. This electricity will be obtained from other sources, such as imports, possible acquisitions from the December 1994 Request for Proposals and future requests for proposals.

On the demand side, the Plan includes community energy planning and a commitment to the level of demand-side management in the *Draft 1995 Demand-Side Management Plan*, although the nature of the programs will change over the next several years from provision of rebates and incentives to provision of customer services on a cost-

Table 7.1:

BC Hydro's 20-Year Outlook for Demand-Side and Supply-Side Resources

RESOURCE ADDITIONS	ESTIMATED IN-SERVICE DATE
SUPPLY-SIDE RESOURCES:	
Seven Mile Unit 4	2000
Revelstoke Unit 5	As early as 1999
Revelstoke Unit 6	2008
Stave Falls Powerplant Replacement	Late 1999
Burrard Thermal: full repowering	Earliest in-service for first two modules;3rd and 4th modules subject to further analysis
Mica Unit 5	2012
Other requirements met with least cost resources (including possible acquisition from the December 1994 Request for Proposals)	1996 to 2014
DEMAND-SIDE RESOURCES:	
Community Energy Planning	Underway
Draft 1995 Demand-Side Management Plan	Ongoing,with transition

recovery basis. Continuing with the current level of demand-side management is intended to help provide a smooth transition during this period.

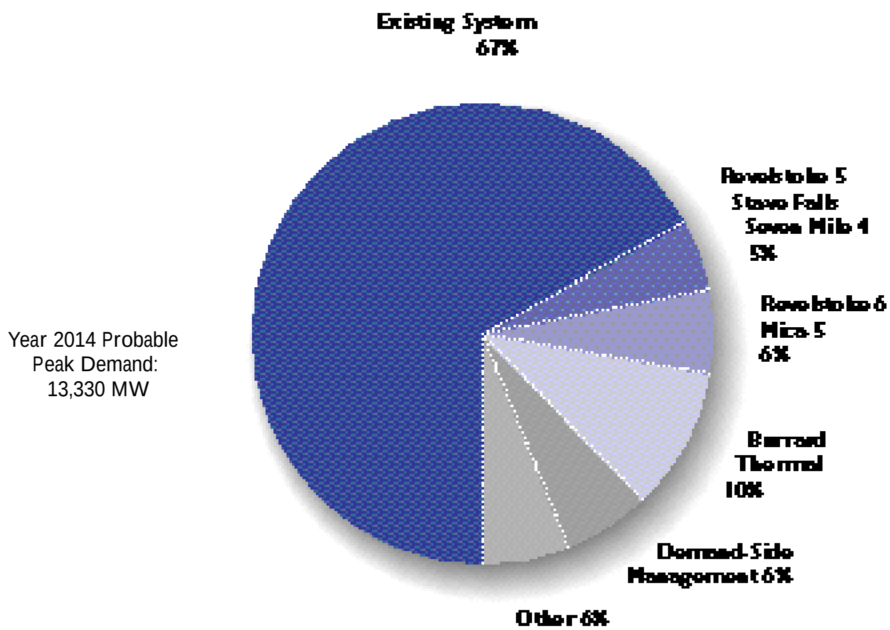
The composition of the 20-Year Outlook is shown graphically in terms of capacity and energy in Figures 7.1 and 7.2 respectively. The contributions of the various resources to capacity and energy are given in Table 7.2. ENVIRO-PLAN output for the portfolio is shown as Figures 7.3 through 7.5.

As shown, the additions cover a variety of resource types. Of these, the largest contributors to capacity are Burrard Thermal and hydroelectric sources. The latter comprise mainly the capacity additions at Revelstoke and Mica, which together account for about 60 percent of capacity additions. The largest contributors to energy are Burrard Thermal and Other resources purchases and possible acquisitions from the December 1994 Request for Proposals and future requests for proposals. Together, these resources account for about 75 percent of energy additions.

BC Hydro's 20-Year Outlook bears many similarities to the portfolio recommendation of the Consultative Committee. All the common elements of the Committee's recommendation are in the 20-Year Outlook, as are the elements of subset F1. Differences from subset F2F are small in the short term, as the additional demand-side management in this subset does not begin to take effect until 2003. BC Hydro's interest in acquiring new resources on the basis of economic cost precludes acquisition of alternative technologies–or other resource types –in advance of cost-effectiveness, although developments in these technologies will be monitored. At this time, BC Hydro has chosen to maintain the flexibility to fully repower Burrard. As mentioned, this project will be subject to further study prior to making commitments.

No specific rate options from the inventory were included in the 20-Year Outlook, as these require further study and development. BC Hydro is moving to unbundle and rebundle electricity products and services to be better able to compete in evolving electricity markets[1]. In the

1 Unbundling means disaggregating electricity products and their transportation into sub-products that meet customers' needs. These sub-products include energy (with price varying by time),capacity, storage, standby (energy and/or capacity) and transportation. Rebundling involves combining some of these sub-products into packages to meet the specific needs of customers.



The 20-Year Outlook for Capacity Resources (excluding reserve margin)

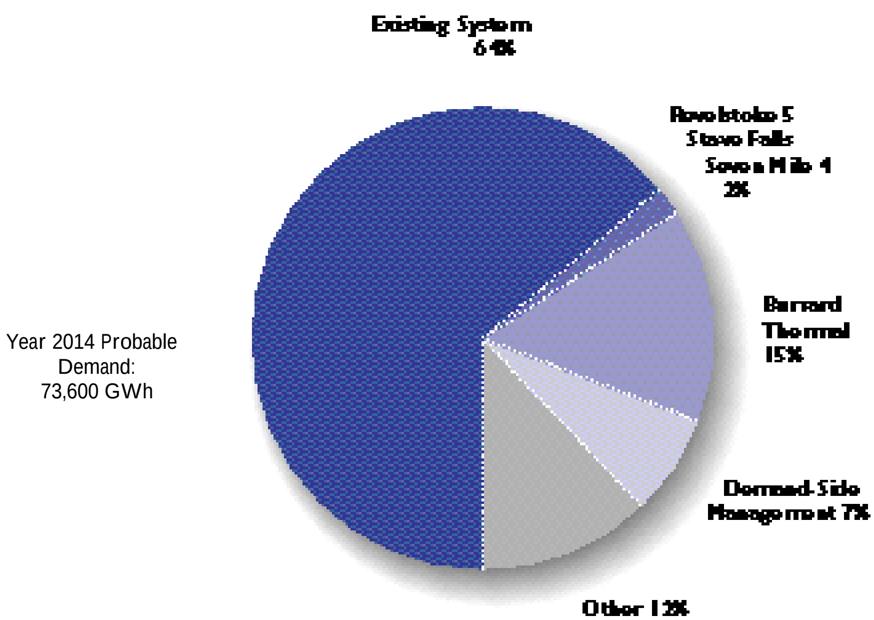


Figure 7.2:

The 20-Year Outlook for Energy Resources

(Note:Some projects provide capacity but little or no energy. This results in the differences in the percentages indicated above.)

Figure 7.3:

ENVIROPLAN Output for 20-Year Outlook

Figure 7.4:

ENVIROPLAN Output for 20-Year Outlook

Figure 7.5:

ENVIROPLAN Output for 20-Year Outlook

Table 7.2:

BC Hydro's 20-Year Outlook: Capacity and Energy Additions

RESOURCE ADDITIONS	CONTRIBUTION TO YEAR 2014 DEPENDABLE CAPACITY (MW)	CONTRIBUTION TO YEAR 2014 AVERAGE ANNUAL ENERGY (GWH/YEAR)
SUPPLY-SIDE RESOURCES:		
Seven Mile Unit 4	90	250
Revelstoke Units 5 and 6	1,000	0
Mica Unit 5	435	0
Stave Falls Powerplant Replacement	90 (52)	410 (310)
Burrard Thermal: full repowering	1,420 (40)	11,100 (6900)
Purchases and private sector projects	900	8,400
DEMAND-SIDE RESOURCES:		
Community Energy Planning	75	400
Draft 1995 Demand-Side Management Plan	725	4,350

• Numbers in parentheses represent existing plant capability which is retired as new additions are made. For example, the additional energy increment of a repowered Burrard over the existing plant is approximately 4,200 GWh per year.

short term, BC Hydro will be consulting with its industrial customers to help define a number of unbundled products and services to meet their needs and expectations which were identified during the recent public review of the electricity market structure. BC Hydro will also seek approval of appropriate wholesale wheeling rates as required for its participation in regional transmission groups serving the west coast of North America. In accordance with British Columbia Utilities Commission directions, BC Hydro will also move to full recovery of standard charges.

Longer-term issues include identifying current and new products and services, with associated pricing, and developing a transition strategy to move from the current provision of bundled products and services to unbundled products and services for all customer classes.

7.2.3 Transmission Requirements of the 20-Year Outlook

The 20-Year Outlook includes more incremental generation in the high demand regions of the province. For the transmission analysis, the generation is assumed, by the end of the planning period, to be equally split between the Lower Mainland/Vancouver Island and the north and south interior[2]. As a result, the need for new interior to Lower Mainland transmission is expected to be deferred beyond the planning period. Establishment of an active corridor preservation program for the Nicola to Meridian line will be reviewed.

Transmission reinforcements for the 20-Year Outlook are similar to those for the portfolio subsets recommended by the Consultative Committee, discussed in Section 6.6. Differences are largely a matter of timing. The planned reinforcements are shown on Table 7.3. Details of the transmission analysis are provided in Appendix H.

2 This is in contrast to the existing split, where over 80 percent of the province's generation is located in the north and south interior regions.

The existing 138 kV cables and high voltage direct current (HVDC) transmission system to Vancouver Island are aging. The two 138 kVAC cables are expected to be retired by the year 2000. Pole 1 of the HVDC system is planned for retirement by 2002 and Pole 2 by 2007. The HVDC cables to Vancouver Island are expected to be retired around the year 2013.

However, over the planning period, Vancouver Island capacity demand is forecast to grow by approximately 50 MW per year. New options to serve Vancouver Island are therefore required. The most likely transmission options for increasing power supply to Vancouver Island include:

- addition of a seventh submarine cable to serve as a spare phase for the existing two Malaspina to Dunsmuir 500 kV circuits;
- construction of a new HVDC transmission system, including replacement of the existing HVDC system with higher capacity (1,400 MW) facilities in stages: Stage 1 would replace Pole 1 in 2002; Stage 2 would replace Pole 2 in 2007; and Stage 3 would add new HVDC cables in 2013; and
- addition of a 230 kV circuit from Arnott to Sahtlam, using the existing 138 kV right-of-way and including the addition of a 230 kV, 400 MVA phase shifting transformer at Arnott[3].

Based on the planning estimates, the seventh cable option was found to be the most economic alternative and so was used in the portfolio analysis. The 20-Year Outlook includes the seventh cable option as early as 2002. Addition of the seventh cable requires the advancement of reinforcement of the Dunsmuir to Sahtlam transmission system, consisting of conversion of these lines (built to 500kV) from 230 kV to 500 kV operation. A new 500kV substation in the Nanaimo area, including a 500 kV transmission loop could be required as early as 2006. Planning, design and implementation of distribution automation for peak load shaving of distribution loads on Vancouver Island will continue.

In the south interior, addition of a fifth generating unit at Mica will require the installation of series capacitor banks to increase the power transfer capability of the Mica to Nicola 500 kV lines.

7.2.4 Decisions on Issues

The portfolio development and evaluation process identified four key issues. As documented in Chapter 6, these issues were discussed extensively with the Consultative Committee. They were also discussed as part of the

Table 7.3:

Transmission Reinforcement Requirements for the 20-Year Outlook

REINFORCEMENTS	ESTIMATED IN-SERVICE DATE
Uprating of American Creek Capacitors to 3000 Amperes	1999
Seventh 500 kV Malaspina to Dunsmuir cable Conversion of Dunsmuir to Sahtlam line from 230 kV to 500 kV	As early as 2002
Jingle Pot-Nanaimo Substation upgrade;including 500 kV transmission loop from the Dunsmuir to Sahtlam right-of-way	As early as 2006
Guichon (5L87) 65 percent series capacitor station	2008
100 Mvar mechanically switched shunt capacitors	2010
200 Mvar mechanically switched shunt capacitors	2012
Distribution automation for peak load shaving of distribution loads on Vancouver Island	Ongoing

3 Arnott station is in Delta.

BC Hydro managers' portfolio development process. BC Hydro's decisions on these issues, as reflected in the 20-Year Outlook, are discussed below.

EARLY WOOD RESIDUE

BC Hydro indicated it would not acquire wood residue projects ahead of other projects which may have lower economic cost or other impacts, as measured by the trade-off attributes. The presence of three wood residue projects on the short list from the December 1994 Request for Proposals indicates there are cost-effective wood residue projects that would have little positive or negative rate impact on BC Hydro's customers. BC Hydro will continue to encourage wood residue projects to be submitted in response to future requests for proposals and will assess them on a competitive bid basis. This decision is consistent with the Consultative Committee's Portfolio F1, where wood residue projects would be chosen in order of economic cost.

ALTERNATIVETECHNOLOGIES

Because of the cost and rate implications, the Outlook does not introduce alternative technologies in advance of cost-competitiveness. This decision is consistent with Portfolio F1; however, BC Hydro recognizes the potential future role of alternative technologies in meeting electricity demand and the need to monitor their development. Furthermore, alternative technologies may have a cost advantage in non-integrated areas[4] or where distribution extensions may be uneconomic. BC Hydro will continue to collect information and monitor developments on the technologies best suited to British Columbia's natural environment, for consideration in those circumstances.

Customer access to electricity generated by alternative technologies could be enhanced through such concepts as a 'green fund' or 'green'rates. Power banking – or net billing – could allow alternative energy producers to use the power system for storage with opportunity for cost recovery. Proposed actions on these concepts are identified in Chapter 8.

AMOUNT OF DEMAND-SIDE MANAGEMENT

While reducing the level of demand-side management in the Plan would have further reduced short-term rates, the trade-off was made to maintain the level of demand-side management at that of the *Draft 1995 Demand-Side Management Plan* in the interests of environmental objectives, system cost and long-term rate impacts[5]. There are, however, some members of the Consultative Committee who are concerned about the impact of higher rates due to demand-side management programs. BC Hydro is also concerned about loss of market share to self-generation or future retail competition if its industrial and other rates become uncompetitive.

Because of this concern, and as part of an evolving customer services strategy, BC Hydro is updating its approach to demand-side management away from incentives and rebates to energy efficiency customer services on a cost-sharing and cost-recovery basis. In this transition to value-added customer services, initiatives from the current *Draft 1995 Demand-Side Management Plan* will continue to dominate activities in this fiscal year. Over the next several years BC Hydro will continue to demonstrate its commitment to encouraging conservation by using special incentives on a limited basis in the residential and commercial sectors and supporting activities to introduce energy services into those markets. In the industrial sector the focus will be on technical assistance programs. BC Hydro will pursue rate design, load management and targeted load growth opportunities[6], continuing to use trade allies and external resources to deliver these energy services.

4 Non-integrated areas include those communities and customers which BCHydro serves but which are not connected to the provincial electrical grid.
5 As discussed in the IDEA,Inc. report,higher levels of demand-side management generally result in higher rates in the short term;however, these rate differentials even out,often crossing over so that higher levels of demand-side management may result in lower rates in the long term.
6 Targeted load growth provides the opportunity to increase load in areas where the existing electric system infrastructure is underutilized. For example, a technology which is more electricity intensive could be recommended to displace more costly or environmentally damaging technologies or fuels.

As a resource option, demand-side management programs will be encouraged in any future requests for proposals to provide electricity to BC Hydro. Demand-side options will be evaluated on an equal basis with supply-side options offered at the same time.

BC Hydro's approach to demand-side management falls between the recommendations in portfolios F1 and F2F; however, since many of the additional measures included in F2F rely on technologies not yet available, in the short term, there is little difference between F2F and the selected portfolio.

BURRARD REPOWERING

The option to upgrade all six existing units at Burrard is no longer the most economic. The 20-Year Outlook includes provision for full repowering at the Burrard Thermal plant, based on the positive performance of this option on cost, rate and most environmental attributes in a portfolio context. However, inclusion of full repowering at Burrard is not unconditional. Because of uncertainties related to a variety of factors, such as gas price risk which is discussed in Section 7.3, the Plan recommends that flexibility be maintained. Instead of seeking approval now for full repowering, the Plan recommends that each step toward full repowering (i.e., each sequential unit) be subject to detailed investigation, public consultation, and regulatory review before specific commitments to repowering are made.

This decision is consistent with portfolio F1, but provides sufficient flexibility to address local or greenhouse gas emissions regulations, natural gas supply and price issues, technology development and changes in cost-competitiveness with other resources. It also includes the flexibility to optimize repowering with the timing of capacity additions at Revelstoke and Mica and other options from the private sector.

7.2.5 Performance of the 20-Year Outlook Measured by the Trade-Off Attributes

Figure 7.6 is the Attribute Profile for the 20-Year Outlook and the Consultative Committee's recommended portfolio and subsets, F1 and F2F[7]. The profile shows the performance of the portfolios relative to the Reference Portfolio. The range of attribute values spanned by these portfolios is indicated by the vertical lines. The values have been normalized so the range is equal to one. The relative position on the vertical lines is an indication of the portfolio performance: points near the top of the vertical lines indicate poorer performance; those near the bottom indicate better performance. The Reference Portfolio, which is the benchmark used throughout the trade-off analysis, plots along the zero line for all attributes. As discussed in Section 6.5, this attribute profile shows the decomposition of the system cost attribute, separating the BC Hydro component from the demand-side management customer cost component of the attribute.

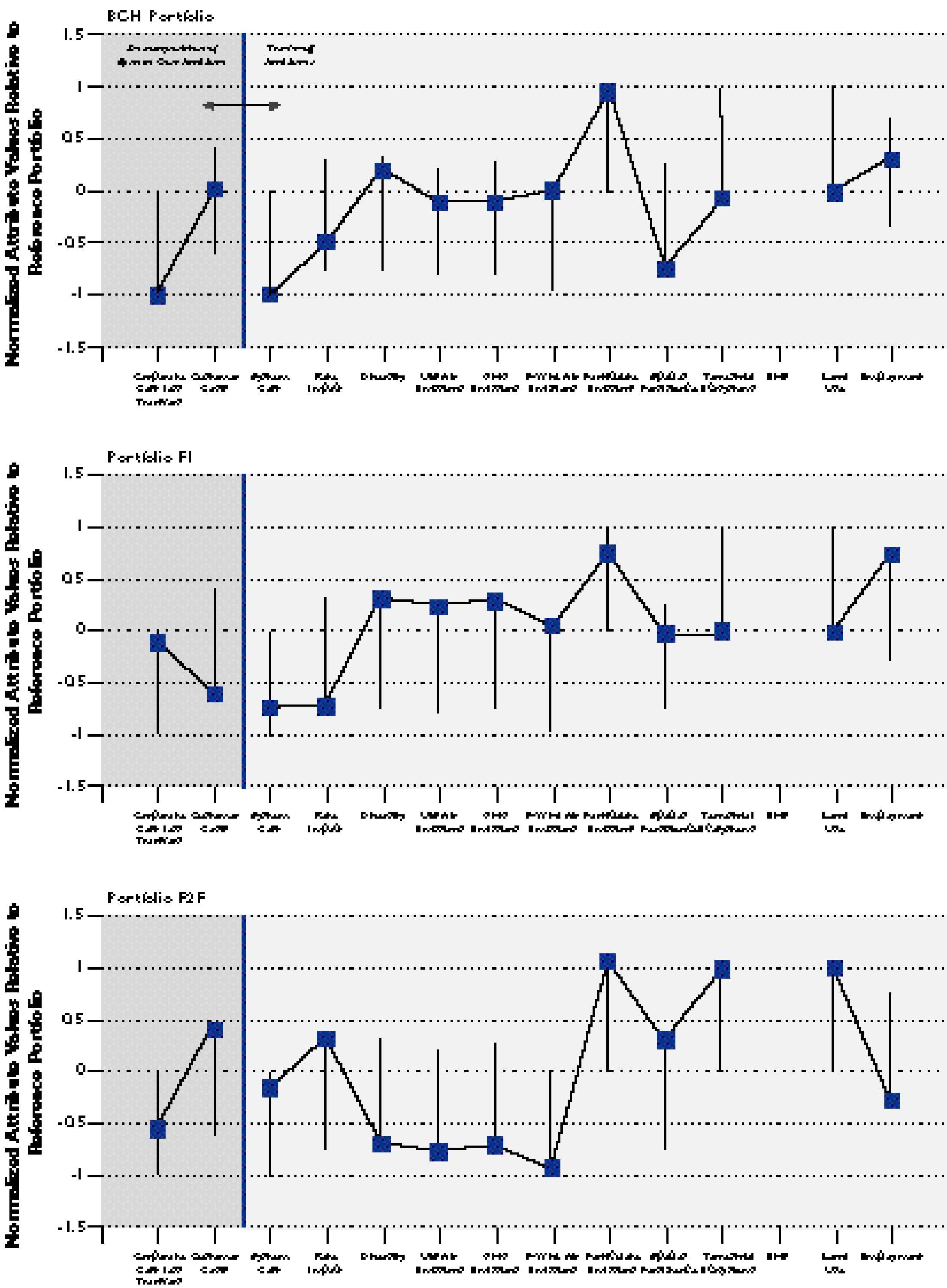
The attribute profile shows that the BCH portfolio performs best or near-best on the system cost, rate impact, species persistence, terrestrial ecosystems, and land use attributes. Relative to the other portfolios, it performs moderately well on upstream air and greenhouse gas emissions, lying approximately mid-way in the range. This is one of the principal trade-offs reflected in the 20-Year Outlook. Air emissions for the selected portfolio do increase over current levels, due to increased reliance on natural gas-fired generation. This trade-off minimizes cost and rate increases, providing BC Hydro with the flexibility to respond to a changing electricity market structure.

On the diversity index, portfolio performance is similar to the Reference and F1 Portfolios, but is less diverse than F2F. This is a reflection of the proportionally fewer new resource additions in the portfolio. The BCH portfolio maximizes developments at existing facilities such as Revelstoke, Mica, Stave Falls, Seven Mile and Burrard and adds fewer new or green field projects.

7 Attribute profiles were introduced in Chapter 6. They are used to assist in the comparative evaluation of portfolios.

Figure 7.6:

Attribute Profiles for BC Hydro's and Consultative Committee's Recommended Portfolios



The BCH portfolio provides moderate levels of employment, between the range for portfolios F1 and F2F. Much of this comes from the respending effects of demand-side management programs. The BCH portfolio performs poorest on particulate and population-weighted air emissions. As discussed in Chapters 5 and 6, this is a reflection of the assumed amount and timing of additions of wood residue projects to the portfolio[8].

As discussed in Section 6.6, there is no significant overall difference in magnetic field exposure levels between the two subsets of the Consultative Committee's recommended portfolio. Transmission requirements of the selected portfolio are similar to those of portfolios F1 and F2F, therefore, magnetic field exposure associated with the selected portfolio is also similar; i.e., increases in magnetic field exposure levels along some transmission lines are balanced by decreases in exposure levels along other lines.

In summary, BC Hydro's selected portfolio provides a balance between short and long-term objectives, while taking into account the views of its stakeholders on sustainability and economic efficiency by minimizing the extent of new resources. The 20-Year Outlook performed well in a variety of scenarios, discussed below, showing flexibility to adapt to a changing future and electricity market environment.

7.2.6 Application of Weights to the Final Portfolios

Table 7.4 shows an evaluation of the final portfolios inferred from the weights of three members of the BC Hydro managers group and three members of the Consultative Committee. The portfolio weighting summation scores[9] shown in the table were obtained by multiplying the normalized attribute values for each portfolio by the weight assigned to that attribute by each stakeholder[10].

The scores in Table 7.4 reflect the diversity of values held by stakeholders in each group. Of the three individuals from each group, one places relatively high weight on cost factors (Manager X and Consultative Committee member U), another places relatively high weight on environmental factors (Manager Y and Consultative Committee member W) and the third reflects a balance among the attributes (Manager Z and Consultative Committee member V).

The weighting summation scores show that BC Hydro's selected portfolio is ranked highest using the weights from these stakeholders in all cases except one, where the individual places 50 percent of the total weight on air emissions.

Figures 7.7 through 7.10 are graphical displays of the weighting summation results, where the contribution to the overall portfolio score of each group of attributes can be seen. In three of these four figures, the BCH portfolio has the highest score – indicating it ranks highly across a wide range of weights – even though the contribution to the overall score from each category of attributes is different. This can be seen by looking at the relative size of each of the shaded areas representing the six attribute categories. The scores are high because the BCH portfolio performs well or at least moderately well, not only on cost factors, but also on the other non-air attributes. Even in the case where one stakeholder – individual W – places zero weight on cost factors, the BCH portfolio performs well. Nevertheless, at least one stakeholder prefers portfolio F2F as it clearly performs best on air emissions, which this individual weights highly.

8 When all portfolios were compared without any wood residue projects, the BCH portfolio performed well on these attributes relative to the other portfolios.
9 Weighting summation is discussed in Appendix F.
10 Although weights were assigned to the EMF attribute, no values are shown as this attribute was not quantified for the trade-off analysis. See discussion in Section 6.6.

7.3 Scenario Analysis

7 3.1 Purpose and Identification of Scenarios

Long-range planning requires many assumptions on conditions over which planners and decision makers have no control, such as future natural gas prices. Scenario analysis is therefore used to test the performance of portfolios under a range of possible futures. A scenario is some combination of assumptions used to test the robustness of a portfolio in a variety of circumstances. Scenarios are also used to identify areas where close monitoring is required to detect gradual changes that may lead to different actions than those originally planned. Strategies to address these changes, risks and uncertainties are developed in Chapter 8.

The scenarios examined in this Plan highlight key uncertainties identified jointly by BC Hydro and the Consultative Committee. Initially, the main drivers of future uncertainty were identified. These drivers were then described and grouped into related themes which could logically be addressed by a set of data assumptions. Relevant data assumptions were identified and, finally, bounds were established for the data assumptions. Because of the limited time available for detailed analysis, not all assumptions could be examined in this Plan. Some of these, such as interest rates and exchange rates, are implicitly dealt with in the demand forecast. The scenarios examined in this Plan include:

- changing gas prices;
- reduced hydroelectricity availability;
- return of the Columbia River Treaty downstream benefits entitlement;
- changing demand outlook; and
- introduction of air emissions taxes.

The scenario analysis focused, for the most part, on three portfolios: F1, F2F and BC Hydro's 20-Year Outlook (referred to in the scenarios as the "BCH" portfolio). The following subsections summarize the scenario assumptions and the portfolio performance under each scenario.

Table 7.4:

Weights Applied to Final Portfolios

ATTRIBUTE CATEGORY	INDIVIDUAL WEIGHTS						INDIVIDUAL WEIGHT CONTRIBUTION TO WEIGHTING SUMMATION SCORE (by portfolio) CC MEMBER U				CC MEMBER V			
	U	V	W	X	Y	Z	REF	F1	F2F	BCH	REF	F1	F2F	BCH
Cost*	80	10	0	85	20	65	0.14	0.69	0.05	0.71	0.02	0.08	0.01	0.09
Diversity	1	15	0	0	15	5	0.01	0.00	0.01	0.00	0.08	0.05	0.15	0.06
Air Emissions+	6	50	50	8	15	16	0.00	0.00	0.06	0.00	0.15	0.02	0.44	0.13
Other Environment++	2	20	50	4	15	8	0.00	0.00	0.00	0.02	0.10	0.10	0.00	0.18
Land Use	4	5	0	0	15	4	0.04	0.04	0.00	0.04	0.05	0.05	0.00	0.05
Employment	7	0	0	3	20	2	0.07	0.03	0.08	0.05	0.00	0.00	0.00	0.00
TOTALS**	100	100	100	100	100	100	0.26	0.76	0.20	0.82	0.40	0.30	0.60	0.51

* Cost includes the system cost and rate impacts.
+Air Emissions includes the upstream air, greenhouse gas, population-weighted local air, and particulate emissions attributes.
++Other Environment includes the species persistence, terrestrial ecosystems, and EMF attributes.
** Totals shown in bold indicate portfolio with highest weighting summation score using each individual's weights.

7.3.2 Changing Gas Prices

NATURAL GAS SUPPLY AND PRICING OUTLOOK

The natural gas market structure has changed dramatically from one of formal contracts for firm supplies to a commodity market. Both buyers and sellers of natural gas rely on competitive supply and demand forces to meet their respective market requirements, and both are exposed to the resulting commodity prices. As the natural gas market continues in a state of flux, prices have fallen and the effects of a changing market structure continue to be felt. Premiums for long-term firm gas over spot gas continue to decrease.

The number of options for different types of gas purchase arrangements are also increasing. Aside from the different types of gas products – spot, seasonal, and long-term firm – there are now a variety of pricing mechanisms. Fixed prices for one-year or multi-year firm contracts are losing favour compared to the newer options in the market. Contracting for a standard quantity of gas under standard industry terms and conditions can take less than one week. Contracting for larger quantities with special terms and conditions can take less than six months.

The Huntingdon gas market hub, near Sumas, has become the key hub for pricing British Columbia natural gas and has a large and growing natural gas throughput. Presently, about 50 percent of the capacity at Huntingdon is tied to long-term sales contracts; the remainder trades on short-term contracts. Many of the long-term sales are unlikely to be renewed as the buyers and sellers will opt for the flexibility of shorter-term contracts. Three key variables determine Huntingdon prices:

- U.S. Gulf Coast prices, represented by spot prices at the Henry hub in Louisiana;
- the basis differential between Henry hub and Huntingdon hub spot prices; and
- the Canadian/U.S. dollar exchange rate.

The New York Mercantile Exchange (NYMEX) price for natural gas futures is considered indicative of what natural gas prices should be. NYMEX prices are generally equated to a forecast of Henry hub spot prices, which track closely with average U.S. wellhead prices. The basis differential reflects market access and pipeline capacity and tolls. This differential changes with changing market conditions. BC Hydro's current outlook on

Table 7.4: *continued*

INDIVIDUAL WEIGHT CONTRIBUTION TO WEIGHTING SUMMATION SCORE (by portfolio)															
CC MEMBER W				BCH MANAGER X				BCH MANAGER Y				BCH MANAGER Z			
REF	F1	F2F	BCH	REF	F1	F2F	BCH	REF	F1	F2F	BCH	REF	F1	F2F	BCH
0.00	0.00	0.00	0.00	0.04	0.65	0.13	0.82	0.03	0.18	0.02	0.18	0.11	0.58	0.05	0.58
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.05	0.15	0.06	0.03	0.02	0.05	0.02
0.19	0.04	0.39	0.10	0.03	0.01	0.06	0.01	0.06	0.01	0.12	0.02	0.05	0.01	0.14	0.03
0.29	0.29	0.00	0.50	0.04	0.04	0.00	0.04	0.08	0.08	0.00	0.12	0.05	0.05	0.00	0.08
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.14	0.00	0.15	0.04	0.04	0.00	0.04
0.00	0.00	0.00	0.00	0.02	0.01	0.03	0.02	0.16	0.08	0.20	0.12	0.02	0.01	0.02	0.01
0.48	0.33	0.39	0.60	0.13	0.71	0.22	0.89	0.55	0.54	0.49	0.65	0.30	0.71	0.26	0.76

Figure 7.7:
Weighting Summation Results for BC Hydro Manager X

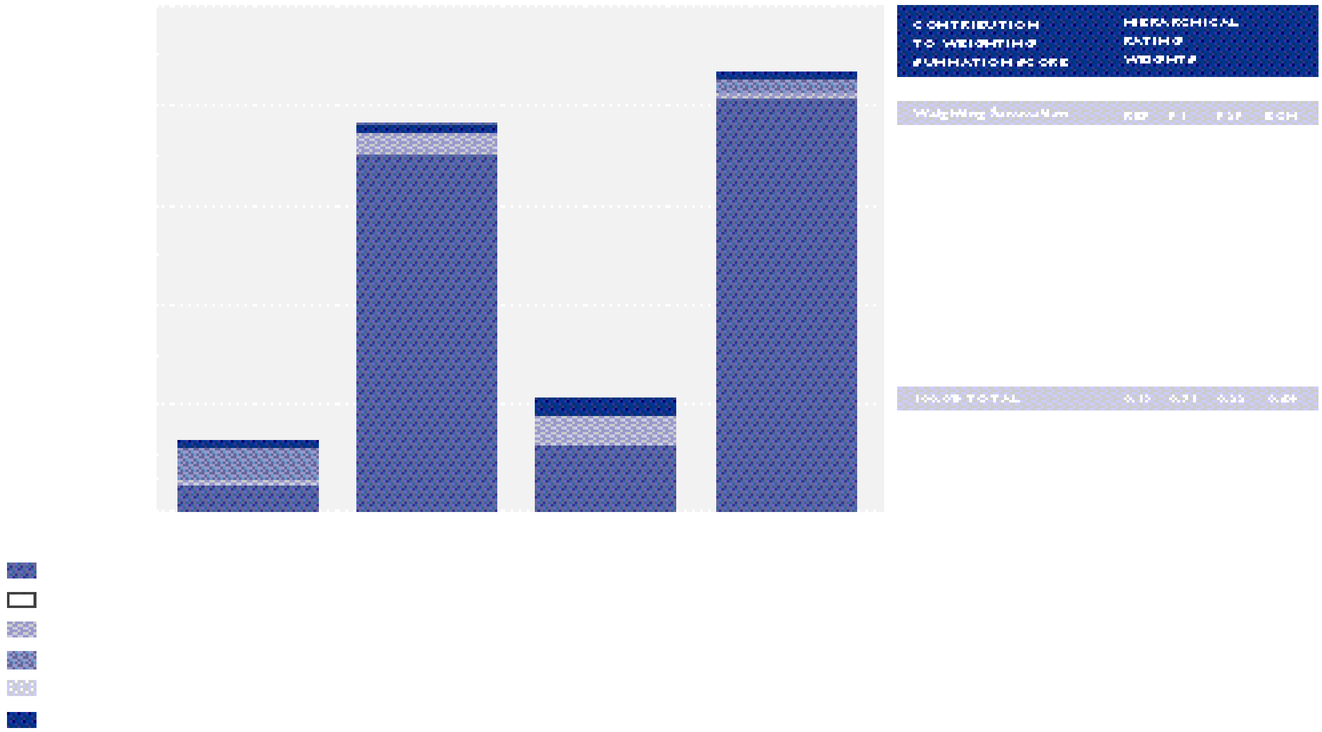


Figure 7.8:
Weighting Summation Results for BC Hydro Manager Y

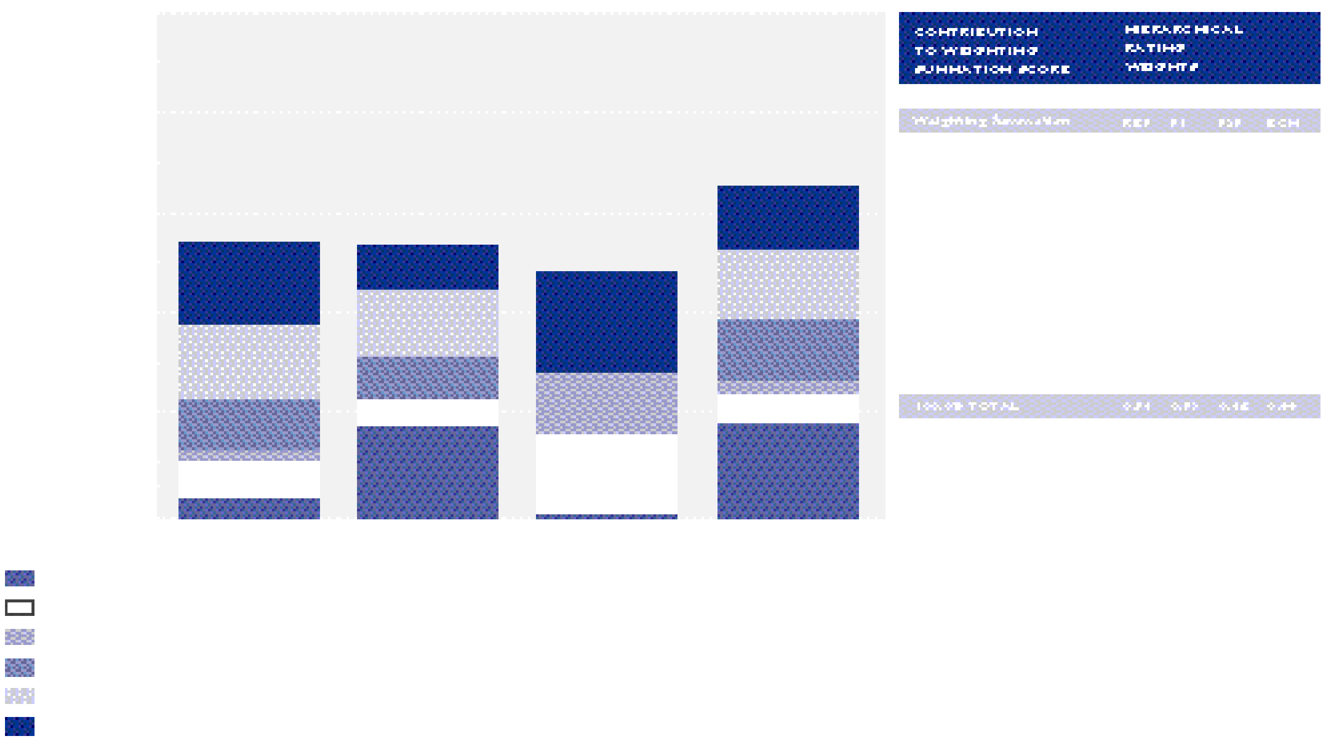


Figure 7.9:

Weighting Summation Results for Consultative Committee Member V

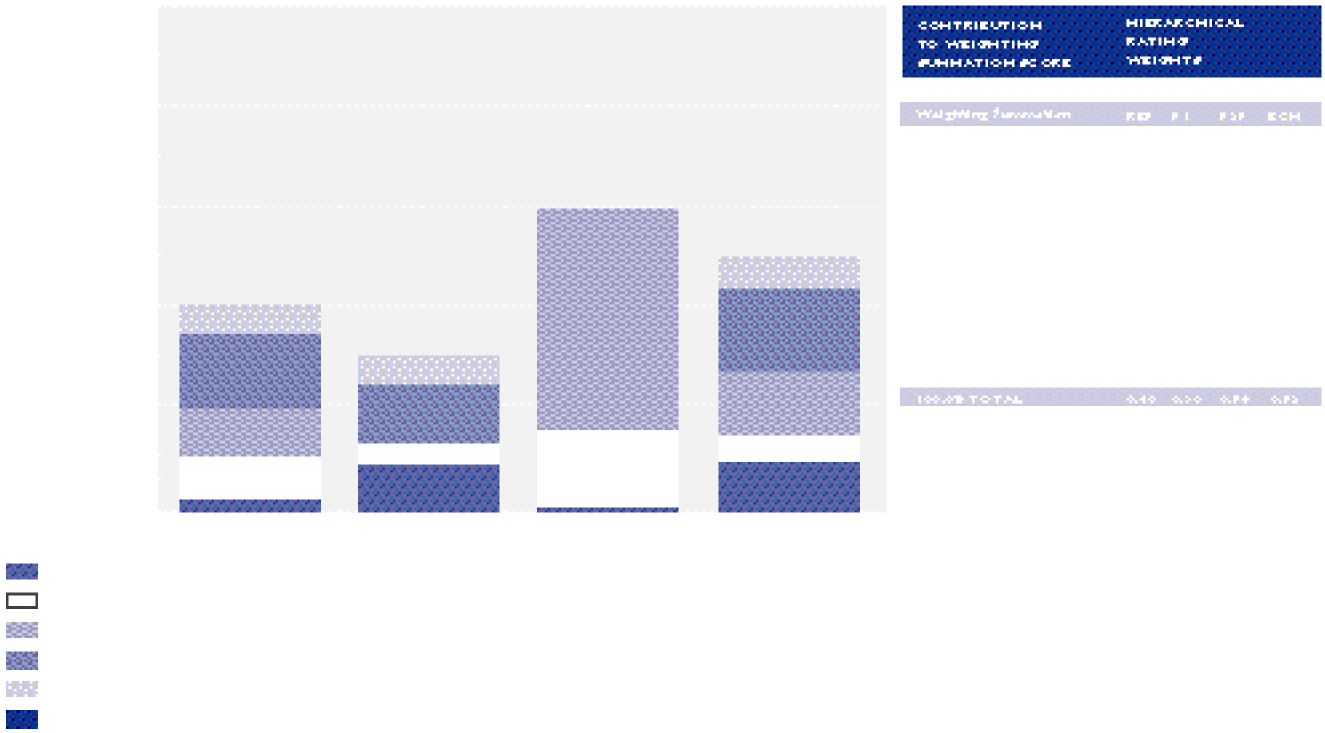
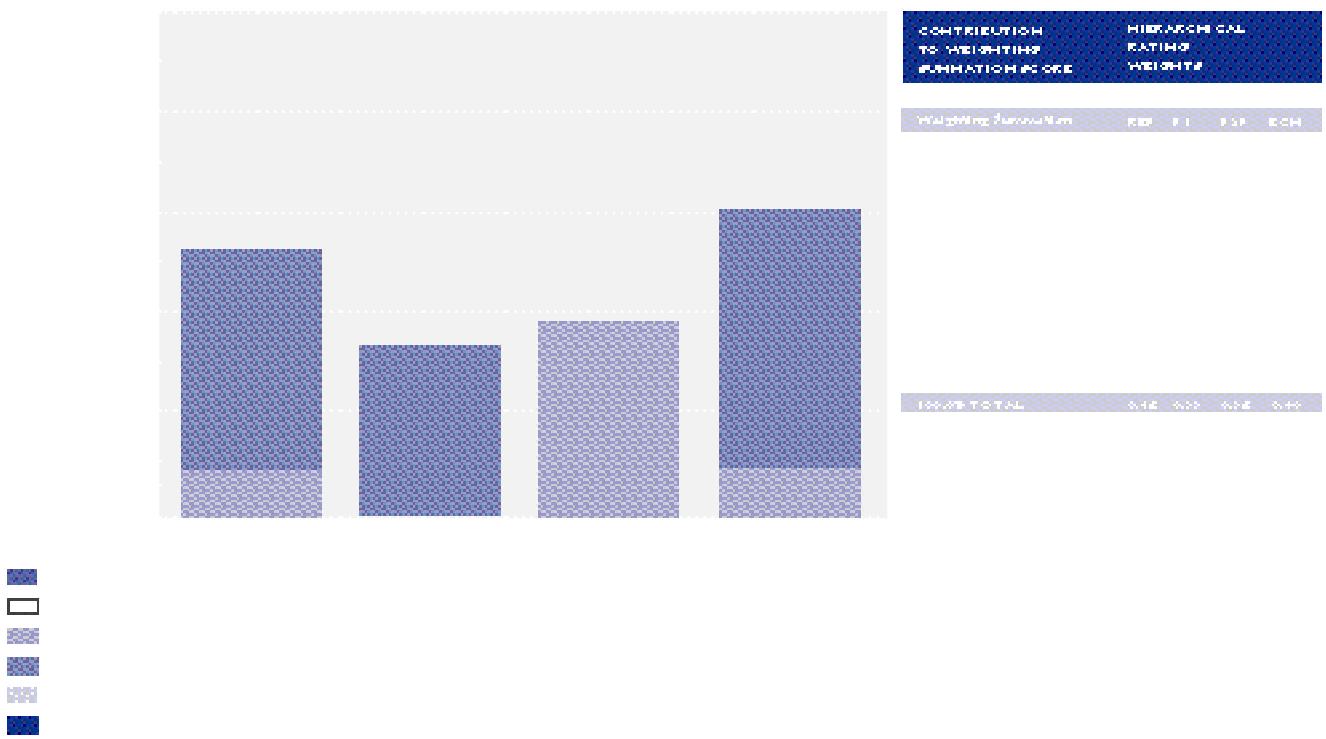


Figure 7.10:

Weighting Summation Results for Consultative Committee Member W



the Canadian/U.S. dollar exchange rate is 0.75 to 0.78 for the period of this Plan.

BC Hydro regularly prepares and updates an outlook of natural gas prices. The present outlook assumes market prices at the Huntingdon hub, considering the three key variables described above, and includes a real price escalation of approximately 1.5 percent per year. Current lower gas price estimates increase the attractiveness of combined-cycle combustion turbine projects; however, the duration over which these prices will persist is uncertain. To test the sensitivity of the final portfolios to changing gas prices therefore, two alternative forecasts for natural gas commodity pricing were used:

- low gas price case: assumes prices remain at current levels in real terms; i.e., prices increase at the rate of inflation; and
- high gas price case: assumes a steady increase in prices real terms, reaching double today's price at the end of the planning period.

For the portfolio evaluations, as well as in this scenario, a single commodity price was used for all natural gas-fired resources, adjusted for transportation to the various regions. For projects in the Lower Mainland and on Vancouver Island, the Huntingdon hub price was used; for projects in the Kootenays, the Empress hub in Alberta was used. Use of a single commodity price ensures a level playing field for all projects.

IMPACT OF CHANGING GAS PRICE ON BURRARD REPOWERING

In the portfolio evaluations described in Chapter 6, repowering Burrard was shown to be more attractive than other options for the plant. Although BC Hydro expects flexibility in the terms and conditions of gas procurement for Burrard from the Huntingdon hub, it is important to test the sensitivity of the repowering options to changing gas price assumptions. A series of portfolios, using the Reference Portfolio as the starting point, were examined under the base case, high and low gas price outlooks described above. The portfolios included:

- repower 2 modules, retain 2 existing units upgraded with selective catalytic reduction and retire 2 existing units;
- repower 3 modules and retain the remaining 2 existing units for (upgraded with selective catalytic reduction) standby use; and
- repower 4 modules.

The results showed that regardless of the gas price assumed, repowering three modules remained an attractive option. Progressively repowering two and three units resulted in decreases both in system cost and rates. Repowering the fourth module however, while continuing to lower system cost, resulted in an increase in rates over repowering three modules. In all the repowering options examined, and for all price cases, system cost and rates remained lower than in the Reference Portfolio. Further detail is provided in Appendix F.

IMPACT OF CHANGING GAS PRICE ON FINAL PORTFOLIOS

Portfolios F1 and BCH perform similarly in the high and low gas price scenarios. F2F, with a limited number of natural gas-fired resources, is less sensitive to gas price risk.

In low gas price conditions, fewer hydroelectric and wood residue projects are added to Portfolios F1 and BCH. Although no more additions of natural gas-fired resources are made than under base case gas price assumptions, the gas plants have greater utilization. This results in a general increase in all air emissions. For example, greenhouse gas emissions in Portfolio F1 increase by 2 percent over the 20-year planning period, from 98 million to 100 million tonnes. In both portfolios, the present value of system cost decreases by approximately $500 million and rates by 1.5 percent compared to the same factors under base case gas price assumptions.

In high gas price conditions, more hydroelectric and wood residue and less natural gas projects are added to Portfolios F1 and BCH. The reduction in natural gas-fired capacity additions is approximately 700 MW in Portfolio F1 and 300 MW in the BCH portfolio. Four modules at Burrard are still repowered in both portfolios. The reduc-

Table 7.5:

Energy Reductions for Reduced Hydroelectricity Availability Scenario

WATER CONDITION	ASSUMED ENERGY REDUCTION (PERCENT)
Critical	15
Medium-low	10
Average	7.5
Medium-high	5
High	0

tion in gas-fired generation results in a general improvement in all air emissions attributes. In the BCH Portfolio, as dispatch is adjusted to reflect high gas prices, greenhouse gas emissions are reduced by about 5 percent over the base case, staying at approximately 6 million tonnes per year over the latter half of the planning period, rather than rising to 7 million tonnes per year. The improvement in air emissions is accompanied by an increase in the present value of system costs of approximately $700 million and an increase in rates of 2 percent over the base case.

In Portfolio F2F, there are no changes in resource additions in either the low or high gas price cases. Consequently there is no change in the non-air environmental attributes and only minor changes in air emissions, primarily decreased emissions in the high gas price case as dispatch of natural gas-fired resources is curtailed. Changes to the financial attributes are smaller in the low gas price case. Present value of system cost is reduced by $200 million and rates by 0.9 percent. In the high gas price case, the change in system cost is an increase of over $400 million and in rates an increase of approximately 1.5 percent.

Compared to the Reference Portfolio, even under the high gas price assumptions, the BCH portfolio remains in the 'win-win' quadrant in a comparison of system cost versus rates. Portfolio F2F moves to the 'lose-lose' quadrant and Portfolio F1 requires a trade-off as rates are still low but system cost increases.

DEMAND-SIDE MANAGEMENT AND GAS PRICE RISK

Demand-side management can be used as a hedge against gas price fluctuations, since programs can be implemented or discontinued on shorter notice than new resources can be built or acquired. Under low gas prices, more demand-side management results in decreased system costs and increased rates; however, under high gas prices, more demand-side management still results in lower system costs but rates decrease. This is due, in part, to the fact that under high gas prices more demand-side management programs would pass the ratepayer impact measure test.

Since the cost-effectiveness of demand-side management is sensitive to changes in avoided supply cost, demand-side management programs need constant monitoring if they are to be effectively used as a hedge on gas price changes, to ensure they are consistent with current economic conditions. This subject is covered in greater detail in the IDEA, Inc. report, Appendix F.

7.3.3 Reduced Hydroelectricity Availability

Changes in operations for environmental management (e.g., to maintain minimum flows from large hydroelectric facilities in support of fish and fish habitat requirements) may result in reduced energy generating potential. Such changes are of importance to BC Hydro because, even with the inclusion in the 20-Year Outlook of some

2,000 MW of natural gas-fired resource options, the 2014 resource mix is still approximately 65 percent hydroelectric.

Minimum flow requirements would have the greatest impact in low flow years. This scenario was therefore constructed to reflect reductions in energy capability for various water conditions, as shown in Table 7.5. Only hydroelectric facilities with significant storage capacity were affected by this scenario. Small and medium hydroelectric facilities, which tend to be run-of-river installations, did not have their energy capabilities reduced. The contribution of these smaller facilities to average annual energy by the year 2014 is approximately 1,950 GWh in Portfolio F1, 2,400 GWh in F2F and 1,650 GWh in the BCH Portfolio.

The largest impact from these reductions in hydroelectricity availability is on the existing BC Hydro system, resulting in an expected average loss of some 3,300 GWh per year. This affects all portfolios equally. The changes to the portfolios, however, are not the same. F2F, with its greater reliance on hydroelectric resource options, is affected slightly more. In this scenario, F2F would require approximately 2,500 GWh per year of unidentified, small and medium hydroelectric resources beyond what has been offered in response to the December 1994 Request for Proposals. In the base case for Portfolio F2F, this requirement is approximately 1,000 GWh per year.

The impacts on the portfolios, as shown in Table 7.6, appear largely in system cost and rate impact. As would be expected, air emissions increase as more thermal resources are used to make up the loss of energy from hydroelectric sources. The additions to the portfolios are unchanged because capacity requirements are still met – it is energy that is required. This energy is made up by decreasing exports and by increasing imports, by some 26 percent in Portfolios F1 and BCH and 17 percent in F2F.

Examination of the potential effects of reduced hydroelectricity availability through this scenario revealed little to distinguish between portfolios; however, it was instructive in showing the magnitude of the impact of minimum flow releases on BC Hydro's largely hydroelectric system, as for example, for fisheries enhancement.

7.3.4 Return of Columbia River Treaty Downstream Benefits Entitlement

The downstream power benefits (DSBs) from the Columbia River Treaty arise from the operation of three storage projects on the Canadian portion of the Columbia River: Duncan dam, Hugh Keenleyside (also called Arrow) dam and Mica dam. These projects regulate river flows, providing flood protection benefits and increasing the generation capability at projects on the U.S. portion of the Columbia River. Canada is entitled to 50 percent

Table 7.6:

Impacts on Portfolios of Reduced Hydroelectricity Availability

PORTFOLIO	INCREASE IN SYSTEM COST (billion $ present value)	RATE IMPACT (per cent increase)	INCREASE IN GREENHOUSE GAS EMISSIONS (million tonnes)
F1	2.2	3.0	24
F2F	3.1	4.5	12
BCH	2.0	3.2	26

Note: Changes shown are for each portfolio relative to the base case assumptions for the same portfolio, not relative to the Reference Portfolio.

(the "Entitlement") of the downstream benefits.

At the time the Treaty was ratified, the Canadian Entitlement for the first 30 years was sold. The Entitlement returns to Canada on the 30th anniversary of the scheduled operation date for each of the three projects; that is, on 1 April 1998 for Duncan dam, 1 April 1999 for Hugh Keenleyside dam, and 1 April 2003 for Mica dam.

The Province of British Columbia is the owner of the Entitlement. As such, it has indicated its desire to maximize the value of the Entitlement to British Columbia. To this end, a Memorandum of Negotiators Agreement was signed by the Province and Bonneville Power Administration (BPA) in September 1994. The key terms of this agreement provided for a partial (all Entitlement above 950 MW) capacity sale to BPA, the return to Canada of 950 MW of capacity and all the energy electricity benefits over existing transmission lines, and the guarantee of flexible access to markets in the United States. In May 1995 however, BPA withdrew from the Agreement, concluding that changes in power markets over the preceding nine months had significantly changed the value of the Entitlement capacity buy-down to itself and other parties in the Pacific northwest.

The Province is continuing to pursue other markets for the Entitlement to maximize the value of the Entitlement to British Columbia. Consequently, there is uncertainty as to whether any or all of the Entitlement will be available to BC Hydro for purchase from the provincial government, and at what price. Because of these uncertainties, return of the downstream benefits Entitlement was examined as a scenario.

The assumptions used in this scenario include:

- return of 950 MW of capacity: 132 MW starting in 1998, an additional 670 MW starting in 1999 and an additional 148 MW starting in 2003;
- return of 4,901 GWh/year of energy: 443 GWh/year starting in 1998, an additional 2,245 GWh/year starting in 1999 and an additional 2,213 GWh/year starting in 2003;
- return of the electricity to the Lower Mainland over existing transmission lines; and
- market opportunity price for the electricity of 3¢/kWh[11].

The Entitlement was 'forced'into all portfolios, that is, the dates and amounts of electricity were specified by the above assumptions. The result was a general deferral of other resource additions. In Portfolio F1, Revelstoke Units 5 and 6 were deferred to 2007 and 2011 respectively; repowering of the second and third modules at Burrard was deferred to 2002 and 2005, with no further repowering; and Mica Unit 5 was deferred beyond the planning horizon. The need for resource additions overall was reduced by about 1,050 MW.

In Portfolio F2F, Revelstoke Unit 5 was deferred from 1999 to 2010 and Unit 6 was deferred beyond the planning horizon. Three modules at Burrard were still repowered; however the second and third modules were deferred five years and three years, to 2005 and 2008 respectively. The need for new resource additions was reduced by about 1,200 MW, which is greater than the capacity of Entitlement added to the portfolio. This is because the Entitlement provides both energy and capacity to a portfolio where the contribution to dependable capacity of the alternative technologies is lower than from an equivalent amount of conventional resources.

In the BCH Portfolio, Revelstoke Unit 5 was deferred from 1999 to 2008; Revelstoke Unit 6 and Mica Unit 5 were deferred beyond the planning horizon. Only three modules at Burrard were repowered: in 2004, 2006 and 2011, which is from five years to seven years later than under the base case assumptions. New additions were about 970 MW less than in the base case, indicating the Entitlement offsets an almost equivalent amount of new resources.

11 This assumption is based on delivery of the electricity to the Lower Mainland. The actual price would depend on Entitlement availability and market conditions.

Including the Entitlement in each portfolio lowered system cost and rates and resulted in a general improvement for most environmental attributes as the need for development of new domestic resources was deferred. The most dramatic decrease in system cost and rates was for Portfolio F2F, where the lower cost Entitlement displaced or deferred higher cost options. This is shown on Figure 7.11, a trade-off graph for system cost versus rates. For reasons discussed earlier, particulate emissions increased as the downstream benefits displaced wood residue resources. Return of the Entitlement reduced employment and the diversity of the resource mix in the portfolios.

The main effect of the return of the Entitlement is on the amount and timing of new resource additions. These effects begin in 1999 and are therefore discussed in the following chapter which outlines the Four-Year Action Plan. This scenario showed that BC Hydro's selected portfolio has the most flexibility of the final portfolios to accommodate the return of the Entitlement, and that the Entitlement has less impact on the 20-Year Outlook which already has relatively low system cost and rates than it would have in Portfolios F1 and F2F.

7.3.5 Changing Demand Outlook

To assess the risk of over supply or under supply of electricity due to changing demand growth patterns, two demand scenarios were examined. These scenarios simulated an increase in demand and a leveling off of demand after the year 2000. The scenarios are presented graphically on Figure 7.12.

INCREASED DEMAND

The impacts of increased demand were examined using the 'high'forecast contained in the 1994/95 Load Forecast, where demand at the end of the planning period in 2013/14 is estimated to reach some 4,900 GWh/year over the Probable forecast. This increase in demand could arise from:

- increased market share in a future with open access to electricity where BC Hydro begins to serve new customers currently in other jurisdictions;
- increased economic activity and growth of electricity-intensive technologies, such as electric vehicles; or
- changes in societal behaviour patterns which result in consumption of more electricity.

There was little to distinguish the portfolios in the high demand scenario. The present value of system cost in all the portfolios increased by approximately $1.2 billion and rates by approximately 2 percent. This is a direct reflection on the increased costs of adding new supplies of energy and capacity to the system.

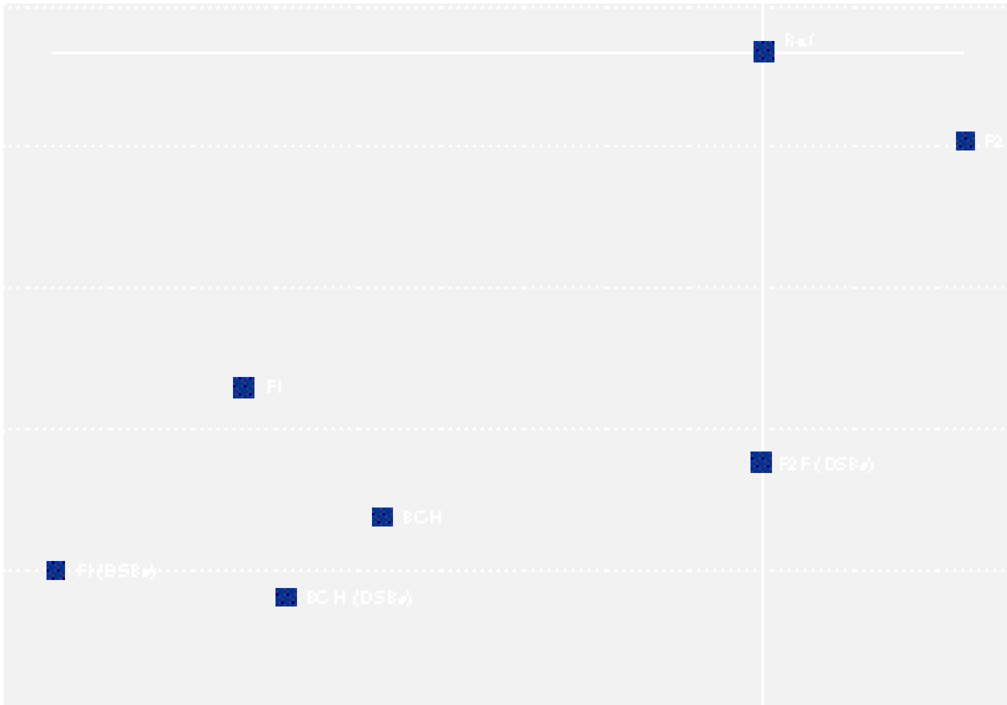
In Portfolios F1 and F2F, additions were required in nearly every year of the planning period; in all 1,000 MW more capacity was added each year to these two portfolios. In the BCH Portfolio, approximately 1,300 MW more capacity was added. There were few changes to the timing of additions in Portfolio F1. In Portfolio F2F, Revelstoke Unit 6 was advanced from 2010 to 2004. Repowering of the third and fourth modules at Burrard were advanced to 2002 and 2004 in the BCH Portfolio. Revelstoke Unit 6 was advanced to 2006 from 2008; however, Mica unit 5 was deferred beyond the planning period as other resources better met both the energy and capacity requirements in this scenario.

While not explicitly examined for this purpose, the high demand scenario would cover the loss of deliveries to BC Hydro under the Alcan Purchase Agreement. Some Consultative Committee members supported a request from the Natural Resources Dependent Sector that BC Hydro characterize three options with respect to purchases of power from Alcan:

- BC Hydro purchases 140 MW (average) from Alcan.
- Others purchase 140 MW (average) from Alcan and BC Hydro wheels the power through its system.
- No one purchases the power and the water which would be used to generate the power is returned to the Nechako River.

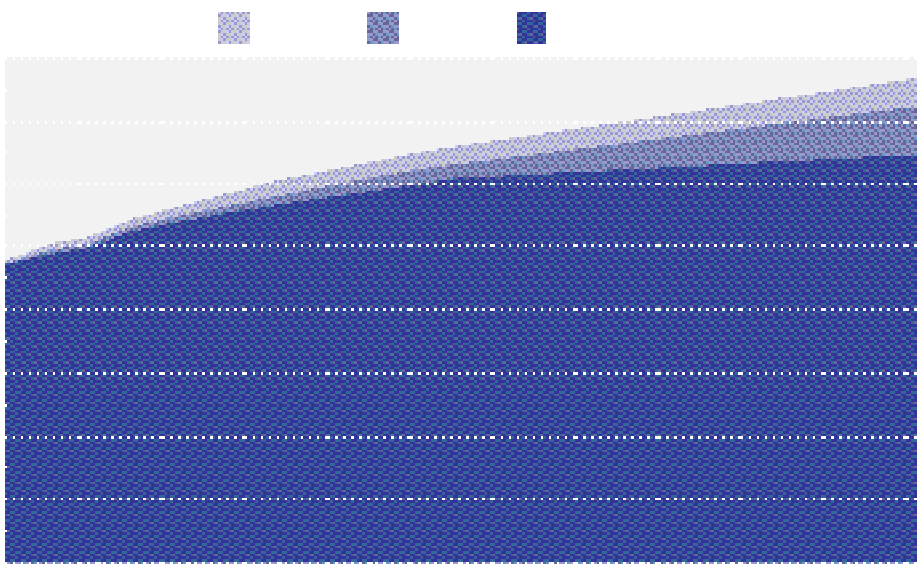
Figur e 7.11:

System Cost vs. Rate Impact for the Downstream Benefit Scenario



Figur e 7.12:

Demand Scenarios Examined



The first option has been characterized and is an element of all the portfolios considered in the planning process. The second option has been characterized and is reflected in the Resource Summaries, although not in the portfolios. If it were included in the portfolios, the result would likely be a reduction in air emissions as the hydroelectricity displaces fossil-fired generation in other jurisdictions; e.g., Alberta or the U.S. If, however, loss of the delivery of 1,225 GWh per year from Alcan to BC Hydro is made up with increased imports, the net result for all portfolios would be a negligible, if any, change. The third option has not been characterized. The analytical results of the high demand scenario would cover the rate and system cost implications of the third option, but would not reflect the environmental impacts on the Nechako River, which are beyond the scope of this Plan. Moreover, the framework agreement between the Province and Alcan includes the opportunity for public input on water management.

DECREASED DEMAND

The impacts of decreased demand were examined using a scenario generated for the 1993/94 Load Forecast. In this scenario, demand was assumed to level off after the year 2000, resulting in a reduction from the 1994/95 Probable Demand Forecast of some 8,500 GWh in the final year of the planning period, 2014. This change in demand growth is used as a proxy for circumstances which alter BC Hydro's obligation to serve, such as:

- loss of market share as customers leave the BC Hydro system for other sources of supply in a future with open access to electricity;
- customers who generate their own electricity (self generation);
- technological changes such as, for example, superconductors which could dramatically decrease losses along transmission lines (which currently are about 8 percent); or
- changes in societal values and behaviour which result in consumption of less electricity.

In the low demand case, there was a general improvement in all portfolios on the environmental attributes as fewer new resource additions were required.

In Portfolio F1, system costs were reduced by $1.4 billion in present value terms while rates increased 2.9 percent compared to the base case for this portfolio. Four modules at Burrard were still repowered; however, the need for Revelstoke Unit 6 was deferred from 2000 to 2013 and Mica Unit 5 was deferred beyond the planning period. In all, 1,500 MW less capacity was added. The Burrard, Revelstoke Unit 5, Stave Falls and Seven Mile Unit 4 projects were sufficient to meet demand until 2008.

In Portfolio F2F, system costs were reduced by $1.6 billion in present value terms and rates increased by 3.1 percent compared to the base case for this portfolio. The rate impact of this portfolio remains the highest overall of the three examined. There were no changes to the portfolio until 2005, after which no further resource additions, beyond the energy and capacity supplied by demand-side management and the alternative technologies, were required. In all, 1,600 MW less capacity was added.

In the BCH Portfolio, system costs were reduced by $1.2 billion in present value terms and rates increased by 3.5 percent compared to the base case for this portfolio. There were no changes to the portfolio until 2004. The third module at Burrard which would have been repowered in that year under base case demand assumptions was deferred until 2013 and the fourth module was not repowered. Revelstoke Unit 6 was deferred to 2014. Between the years 2000 and 2011, there were no additions other than continuation of the assumed level of demand-side management.

CONCLUSIONS FROM CHANGING DEMAND OUTLOOK

The most significant impact of changes in demand is on rates. In the high demand case, more resources are added, therefore both system costs and rates increase. In the low demand case, less new resources are added; however, costs must be recovered over a smaller number of kilowatt-hour sales, necessitating higher rates. The scenario analysis showed that the magnitude of rate increases over the base case demand assumptions is higher in the decreased demand case than in the increased demand case.

Portfolio F1 appears to be the most flexible in both the high and low demand cases. For the BCH Portfolio and F2F, demand-side management energy and capacity savings are important in the high demand case, not only to 'buy' added time to bring new resources on line, but also to defer new additions as long as possible. In the low demand case, however, the level of demand-side management in these portfolios provides more energy and capacity than required, resulting in poorer cost and rate performance compared to F1.

The demand scenarios showed Portfolio F2F to be at higher risk if demand increases, as it is limited in terms of resource additions consistent with the objectives of the portfolio; i.e., to minimize environmental impact. F2F loses its advantage of low gas consumption in the high demand case as more natural gas-fired resources, and the fuel costs associated with operating those resources, are added to the portfolio.

While the BCH Portfolio is more at risk in the low demand case, and loses some of its cost and rate advantages compared to F1, assumptions on demand do not necessitate any changes in plans in the short term, since there is no difference in the portfolio under the various demand cases until 2002 should demand increase and until 2004 should demand decrease. These scenarios indicate the extent of demand-side management, and program performance, need to be carefully monitored and adjusted to fit changing demand outlooks.

7.3.6 Introduction of Air Emissions Taxes

The *Resource Acquisition Policy* describes the approach to social costing which BC Hydro has adopted in response to the Government's 1992 *Policy Statement on Independent Power Supply to BC Hydro*. The treatment of externalities in the *Resource Acquisition Policy* consists of monetizing air emissions and qualitatively evaluating other impacts. For this Plan, the multi-attribute trade-off analysis provided the framework for quantitative evaluation of resource options according to the trade-off attributes. The analysis captured air emissions in terms of changes in the physical quantity of emissions (tonnes emitted); however, the original specification of the trade-off attribute also allowed for monetization.

Some members of the Consultative Committee were interested in examining the implications of monetizing air emissions, including the monetized values in resource selection and dispatch decisions, and levying an emissions 'tax' equal to the monetized values. To address this interest, three scenarios were examined:

- a tax on greenhouse gas emissions was applied without changes in resource acquisition or dispatch decisions;
- taxes on local air and greenhouse gas emissions were applied, where the amount of these taxes was included in resource selection and dispatch decisions; and
- selection and dispatch choices were made giving consideration to alternative (higher) values of local air and greenhouse gas emissions taxes, without actually levying the taxes.

APPLICATION OF A GREENHOUSE GAS EMISSIONS TAX

In this scenario, a tax of $15/tonne – the externality value for greenhouse gas emissions specified in the 1994 Resource Acquisition Policy – was levied, assuming no change in resource selection or dispatch; that is, BC Hydro simply pays the tax and passes the cost on to customers through rates. In this scenario, the result is reflected wholly in the rate impact attribute. For Portfolio F1, rates increase 3.4 percent over the base F1 case. Even for F2F, with its limited dependency on thermal resources, the rate impact attribute shows a 2.1 percent increase over the base F2F case. For Portfolio BCH, the rate increase is 3 percent.

This analysis suggests changes to the resource mix and dispatch should be investigated in the advent of greenhouse gas emissions taxes. Impacts of a greenhouse gas tax are further discussed in Appendix F.

APPLICATION OF BOTH LOCAL AIR AND GREENHOUSE GAS EMISSIONS TAXES

To estimate the magnitude of resource selection and utilization changes that would be made if BC Hydro acted to limit its tax burden with the introduction of air emissions taxes, the portfolios were examined again, this time with taxes applied to all air emissions at the externality values specified in the *Resource Acquisition Policy* . The resulting higher unit energy costs for thermal resources were used in making selection and dispatch decisions. The results are shown in Table 7.7 for a sample of the trade-off attributes. Changes to the resource mix are shown in Table 7.8. The changes shown are for each portfolio relative to the base case assumptions for the same portfolio, not relative to the Reference Portfolio.

As shown in Table 7.7, there is a decrease in system cost for all portfolios. This reflects differences in cost as a different resource mix is selected as well as a reduction in fuel costs as natural gas-fired thermal resources are dispatched less or simply not acquired. Table 7.8 shows that the increase in hydroelectric and wood residue resources acquired in Portfolios F1 and BCH is not equal to the amount of natural gas-fired resources displaced. This is because exports are curtailed to meet domestic needs. Moreover, imports – since they are assumed to originate from thermal generation and so are charged with the applicable air emissions taxes – are reduced.

There are no changes to the additions in Portfolio F2F; only the dispatch is adjusted and, like the other Portfolios, exports are curtailed. In the BCH Portfolio, the fourth module at Burrard is not repowered.

RESOURCE SELECTION AND DISPATCH DECISIONS WITH ALTERNATIVE VALUES OF EMISSIONS TAXES

A final scenario was run to examine the changes in resource choices and utilization which would be made if alternative values of emissions taxes other than those in the *Resource Acquisition Policy* were applied. The alternative values and their basis are presented in Section 5.3; they are higher for all emissions, most notably for particulates. In this scenario, the taxes were simply calculated and included in the selection and dispatch; they were not levied. The results of this scenario are shown in Table 7.9 and Table 7.10, for changes in trade-off attribute values and resource mix respectively. As in the previous tables, these changes are for each portfolio relative to the base case assumptions for the same portfolio, not relative to the Reference Portfolio.

Note in this case the system costs increase as do population-weighted air emissions for all portfolios. The increase in the system cost attribute reflects the acquisition of higher cost resources and a reduction in export revenues. The increase for the BCH Portfolio is larger than for the others; however, because of its low system cost under base case assumptions, it remains overall the lowest system cost portfolio of the three examined. Unlike the previous scenario, the air emissions taxes were not levied; therefore, the rate impact shown in Table 7.9 reflects the cost of acquiring and operating the different (higher cost) mix of resources. The increase in population-weighted air emissions is attributable to imports. In this scenario, all the portfolios are net importers of electricity. Since imports are assumed to originate from thermal generation and are socially costed at a higher rate, the air emissions component of this attribute prior to population weighting is higher[12].

12 See Section 5.3.4 for an explanation of the components and calculation of this attribute.

Table 7.7:

Impacts on Portfolios of Air Emissions Taxes at RAP Values

PORTFOLIO	DECREASE IN SYSTEM COST (million $ present value)	RATE IMPACT (percent increase)	DECREASE IN GREEN-HOUSE GAS EMISSIONS (million tonnes)	DECREASE IN POPULATION WEIGHTED AIR EMISSIONS (person-tonnes)	DECREASE IN LAND USE (hectares)	DECREASE IN GAS CONSUMP-TION (pj)
F1	146	3.2	11	123	39	187
F2F	69	2.1	4	45	0	71
BCH	33	3	9	123	31	223

Table 7.8:

Changes in Resource Mix with Application of Air Emissions Taxes at RAP Values

PORTFOLIO	DECREASE IN NATURAL GAS-FIRED RESOURCES (MW)	INCREASE IN WOOD RESIDUE RESOURCES (MW)	INCREASE IN HYDRO-ELECTRIC RESOURCES (MW)	UNITS AT BURRARD REPOWERED (NO.)
F1	521	107	321	4
F2F	0	0 (not allowed)	0	3
BCH	207	93	17	3

Table 7.9:

Impacts on Portfolios of Considering Alternative Values of Air Emissions Taxes

PORTFOLIO	DECREASE IN SYSTEM COST (million $ present value)	RATE IMPACT (percent increase)	DECREASE IN GREEN-HOUSE GAS EMISSIONS (million tonnes)	DECREASE IN POPULATION WEIGHTED AIR EMISSIONS (person-tonnes)	DECREASE IN LAND USE (hectares)	DECREASE IN GAS CONSUMP-TION (pj)
F1	66	0.8	14	776	62	492
F2F	66	0.6	5	648	0	252
BCH	212	1.0	15	789	100	546

Table 7.10:

Changes in Resource Mix Considering Alternative Values of Air Emissions Taxes

PORTFOLIO	DECREASE IN NATURAL GAS-FIRED RESOURCES (MW)	INCREASE IN WOOD RESIDUE RESOURCES (MW)	INCREASE IN HYDRO-ELECTRIC RESOURCES (MW)	UNITS AT BURRARD REPOWERED (NO.)
F1	759	106	539	4
F2F	0	0 (not allowed)	0	3
BCH	372	199	352	3

There are no changes to the additions in portfolio F2F; only the dispatch is adjusted. In the BCH Portfolio, the third module at Burrard is not repowered until the final year in the planning period; the fourth module is not repowered.

The rationale for including social costs in the price of electricity is so consumers pay a tariff which reflects the cost to society of producing electricity. Although only air emissions were monetized and examined in the three scenarios above, it is important to note that air emissions are not the only component of social costs. That is why other environmental, social/community and economic development attributes were quantitatively included in the multi-attribute trade-off analysis.

The primary effect of monetizing air emissions – whether the values are levied as a tax or not – is on rates. The change in rates for Portfolio F2F relative to base case assumptions is less than for F1 or BCH, as F2F includes only a limited number of thermal resources which contribute to air emissions. Overall, however, the rate impact of F2F remains consistently higher than either F1 or BC Hydro's selected portfolio.

7.4 Contribution to Objectives

The planning objectives covered issues from economic cost to environmental impacts to promoting new and existing technology. This section reviews the selected portfolio relative to the objectives for the Plan and examines the trade-offs made in decisions on the 20-Year Outlook.

OBJECTIVE 1: Minimize costs of electrical services to customers.

Cost is examined from two perspectives: economic cost and customer rates. As mentioned in Section 5.3, economic cost is one of the trade-off attributes (system cost) evaluated for each of the portfolios. The economic cost for the selected portfolio was the lowest of the three final portfolios (F1, F2F, BCH Portfolio). The selected portfolio contributes to lowering the long-term economic cost of meeting electricity demand and thereby to the overall economic efficiency of the Plan and of the Province of British Columbia.

The cost objective also relates to customer rates. The rate impact for the selected portfolio is among the lowest of all the portfolios examined, reducing rates by 1.5 percent relative to the Reference Portfolio. The comparative reduction for the other final portfolios are a 2.1 percent decrease and a 0.8 percent increase for the 'least rate impact' (F1) portfolio and 'renewable'portfolios (F2F) respectively.

OBJECTIVE 2: Provide quality customer service that meets customer needs and expectations.

This customer service objective is directly related to providing an adequate supply of reliable electricity which meets the energy and capacity needs of the province. The 20-Year Outlook meets this objective as the planning process assumes, for all portfolios, a minimum level of reliability for the system and ensures the selected portfolio contains sufficient resources to meet the demand for electricity and those minimum criteria.

OBJECTIVE 3:
Provide flexible service to adapt to changes.

The intent of this objective is that the Plan be flexible and adaptable to changes in demand, technologies, regulations and customer values. The diversity trade-off attribute addresses this issue, in some portion. A more diverse portfolio, with many different types and sizes of resources, has the potential to reduce vulnerability to changes in demand, technology and regulations. Because it maximizes expansion and efficiency improvements at existing facilities (e.g., Revelstoke), the selected portfolio has a low diversity value relative to a portfolio that emphasizes demand-side management and alternative technologies. However, the selected portfolio does enhance diversity over the current system configuration by introducing new natural gas and wood residue sources. It also performs well in scenarios where demand changes or environmental constraints tighten (e.g., reduced hydroelectricity availability or air emission adders). The portfolio is also sufficiently diverse that a scenario in which natural gas prices dramatically increase did not indicate changes in resource acquisition decisions in the near term.

OBJECTIVE 4:
Provide choice to customers regarding electricity services.

This objective is partially captured by the diversity index, but more directly by the role of rate options and development of new products and services within the 20-Year Outlook. The performance of the selected portfolio on the diversity index was discussed above. Although the 20-Year Outlook does not include any specific rate options in the mix of resources, it does include a rate strategy that will seek approval of wholesale wheeling rates and begin unbundling and identifying new products and services. The rate strategy responds to this objective.

In addition, the evolution of demand-side management from rebate-based to value-added services will provide numerous opportunities to tailor electricity services to specific customer needs, thereby directly contributing to this objective.

OBJECTIVE 5:
Minimize adverse and promote positive environmental impacts.

This objective relates to environmental impacts on land, water and air resources as captured in several environmental trade-off attributes. The selected portfolio performs well on species persistence and terrestrial ecosystems, as defined for this planning process, due largely to the deferral of new transmission lines into the Lower Mainland and the maximizing of development at existing facilities. For example, the selected portfolio alienates about half as much terrestrial ecosystem area as Portfolio F1 and less than 5 percent of that estimated for Portfolio F2F.

However, because of the addition of natural gas-fired resources to the portfolio, greenhouse gas emissions and local air emissions will increase from current levels. Greenhouse gas emissions, for example, are estimated at about 80 million tonnes over the 20-year planning period, compared to about 50 million tonnes for the F2F Portfolio which has a significant proportion of alternative technologies, demand-side management and hydroelectric resources. Analysis of other portfolios indicated that further reductions of greenhouse gas emissions may be possible with acquisitions of more wood residue-fired generation. On the other hand, the inclusion of higher levels of demand-side management in the selected portfolio lowers emissions relative to the F1 Portfolio by about 15 million tonnes over the planning period.

Population-weighted local air emissions in the selected portfolio are higher than those in the F2F Portfolio but lower than in the least rate impact portfolio. The selected portfolio reflects a trade-off between air emission impacts and costs and rates, a common theme throughout the portfolio development process.

OBJECTIVE 6:
Minimize health and safety impacts.

This objective was represented by two attributes: local air emissions and EMF exposure. From the perspective of local air emissions, the selected portfolio tries to balance the air quality issue with implications for costs and rates, performing better than Portfolio F1 but not as well as F2F. The results for EMF exposure are inconclusive, with no difference between the final portfolios. Other aspects of health and safety were not captured.

OBJECTIVE 7:
Optimize socio-economic impacts.

This objective covers a wide range of factors, from minimizing individual disruption or displacement to supporting local or regional economic development. The intent of the objective and sub-objectives is represented in the system cost, land use and employment trade-off attributes.

System cost is a measure of economic cost, so the low system cost of the selected portfolio serves to enhance economic efficiency and economic performance of the province. The land use attribute is a measure of the disruption to a community resulting from land being used for electricity generation and transmission facilities. The selected portfolio performed well on this attribute, with less land use than either Portfolio F1 or F2F. This result follows from the deferral of major new transmission or flooding large amounts of land to create new reservoirs.

With respect to regional economic development, the selected portfolio provides moderate levels of employment (about 19,000 person-years over the planning period). This value lies in the middle of the range for Portfolios F1 and F2F. The largest component of the employment impacts is driven by demand-side management programs (about 3,100 person-years from investment activities and an additional 7,100 person-years from respending effects). Supply-side activities, projects such as Revelstoke, Stave Falls and Mica, provide moderate to good levels of construction employment, but little in the way of permanent employment. The Burrard repowering project and purchases from independent power producers, on the other hand, provide moderate levels of both construction and permanent employment.

OBJECTIVE 8:
Ensure fair and equitable treatment.

This objective referred to a number of aspects of resource planning and allocation. First, the objective calls for fair and equitable treatment regarding evaluation of electrical service options. The planning process followed in this Plan included identification of a wide array of possible resource options and evaluated each against a common set of trade-off attributes, contributing to a consistent and transparent evaluation process and portfolio selection.

Second, it identifies the transfer of wealth among regions, part of which is the concept that generation be located close to centers of demand. With an increased role for Burrard Thermal and possible acquisition of private power projects, the resources selected in the 20-Year Outlook address this objective.

OBJECTIVE 9: Promote implementation of appropriate new and existing technology.

This objective, while not fully captured in a trade-off attribute, was supported by expanding the original list of resource options to include alternative technologies. These technologies were characterized and used in portfolio building and evaluation. The 20-Year Outlook does not include alternative technologies except as they become cost-competitive. However, activities that support long-term opportunities are specified in the Action Plan. Within the resource acquisitions identified in the 20-Year Outlook, repowering at the Burrard Thermal plant would use some of the most advanced and efficient combustion turbine technology. Within transmission, emerging or state-of-the-art technologies such as Flexible AC Transmission Systems (FACTS) and special stability control schemes (also called Remedial Action Schemes) have been applied and will continue to be considered to increase transmission system capability[13].

The Outlook also leaves a provision for purchases from the private sector, with the accompanying opportunity to implement innovative technologies as suggested by the provincial Policy Statement on Independent Power Supply to BC Hydro.

7.5 Summary

BC Hydro's 20-Year Outlook combines demand and supply resources and transmission facilities to meet the forecast demand for electricity over the next 20 years. It maintains the important role of hydroelectric generation and capacity but increases the share of thermal resources, particularly natural gas.

BC Hydro's 20-Year Outlook can be described as low cost, with minimal rate impacts over the planning period. It promotes a moderate level of economic development and performs well on environmental attributes related to land and water resources. The 20-Year Outlook does result in higher greenhouse gas emissions and local air emissions (including particulate emissions), reflecting the increased role of thermal resources.

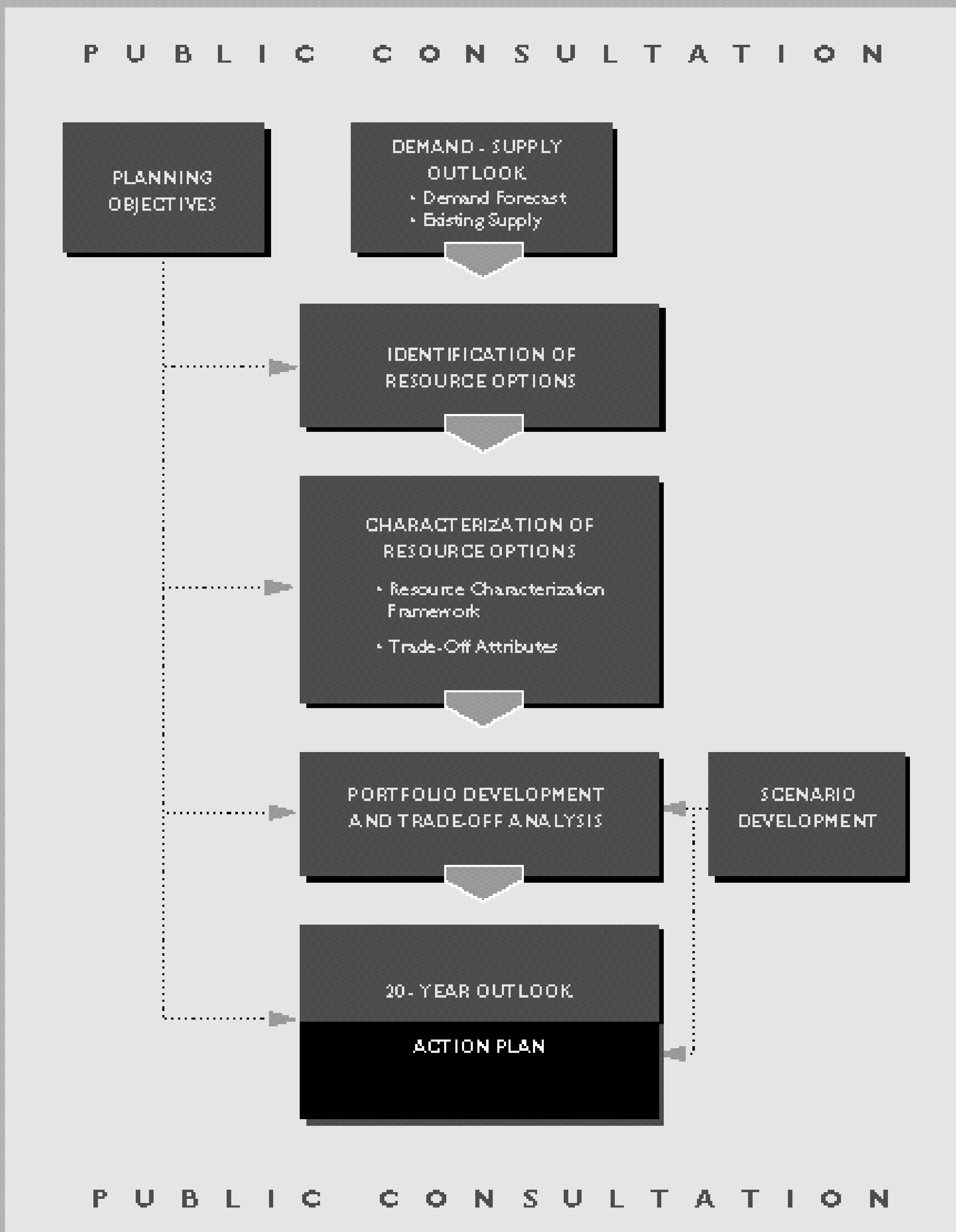
In general, decisions taken by BC Hydro on resource planning issues (i.e., wood residue, Burrard and alternative technologies) anticipate a changing market structure within the electricity industry. The Outlook is cognizant of and has the flexibility to respond to changing market conditions and future uncertainties. Specifically, anticipation of increased competition in generation (e.g., self-generation, wholesale wheeling, fuel-switching) underlies the importance placed on rates and costs to safeguard BC Hydro's competitive position and to avoid stranded investments.

The BC Hydro 20-Year Outlook shares many elements with the Consultative Committee's portfolio recommendation. Indeed, the differences between BC Hydro's 20-Year Outlook and the Consultative Committee's recommendation are very small in the short term (see Chapter 8). The trade-off between rates and air emissions reflected in BC Hydro's 20-Year Outlook underlies the differences between the two subsets of the Consultative Committee's portfolio.

In the next chapter, the first four years of the 20-Year Outlook are examined in an Action Plan. This Plan identifies activities necessary to acquire resources in the next four years, as well as other activities to ensure the future in-service dates of projects identified in the Outlook.

13 The Static VAR Compensator (SVC) at Dunsmuir station and the proposed controlled increased series compensator option are examples of FACTS technology.

CHAPTER 8
FOUR-YEAR ACTION PLAN



8 Four-Year Action Plan

8.1 Introduction

Through the integrated electricity planning process BC Hydro developed a strategy to meet expected future customer demand for electricity. The 20-Year Outlook (Chapter 7) provides the long term view; however, BC Hydro must take actions in the short term to acquire or maintain the availability of the new projects and programs identified in the 20-Year Outlook, and be prepared to respond to risks and uncertainties.

This chapter has three main components: "Resource Acquisitions" presents the projects and programs that BC Hydro plans to further investigate or implement in the next four years; "Links to the *Strategic Business Plan*" demonstrates that the capital and operating, maintenance and administrative costs associated with projects and programs described in the Action Plan are included in the *Strategic Business Plan* and supplementary plans; and "Strategies to Address Risks and Uncertainties" describes how BC Hydro plans to respond to future changes in electricity demand, natural gas prices, resource availability and environmental management and regulation.

For each action identified, a brief scope and schedule one provided. Budgets for the action items are not part of this Plan but will be developed in the business plans of the strategic business units responsible, as shown in Table 8.1.

The Four-Year Action Plan was developed based on current information which needs to be tested to a greater extent and level of detail, taking into account the results of the current review of the electric utility industry in British Columbia, before specific commitments to major acquisitions or expansions identified in the 20-Year Outlook are made.

8.2 Resource Acquisitions

8.2.1 Scope and Definition of Acquisitions

This section identifies the projects and programs BC Hydro plans to continue or initiate over the next four years to serve expected electricity demand. Chapter 6 and 7 provided the justification for the actions described in this section.

Resource acquisitions are commitments to the construction of facilities to produce electricity, contracts to purchase electricity, programs and rate structures to encourage customers to change their electricity use and construction of facilities to transmit electricity. Acquisition activities are grouped into generation, demand side and transmission.

Table 8.1:

Strategic Business Unit Responsibilities For Action Plan Resources

RESOURCES	STRATEGIC BUSINESS UNIT RESPONSIBLE
Generation and Community energy planning	Power Supply
Transmission	Transmission and Distribution
Demand-side management	Customer Services
Rates	Corporate and Financial Affairs

8.2.2 Generation

8.2.2.1 Alternative Technologies

BC Hydro plans the following activities over the next four years:

- Continue to collect information on alternative technologies and to consider these options in planning studies[1].
- On a case by case basis:
  – Continue to support information-exchange events such as the annual Ministry of Energy Mines and Petroleum Resources (MEMPR) Renewables Conference.
  – Continue to lever research and technology funding on renewables and alternatives with agencies such as the Canadian Electrical Association and the Electric Power Research Institute.
  – Participate or partner in pilot projects where alternative technologies look promising and where BC Hydro's participation helps to meet Corporate objectives.

8.2.2.2 Hydroelectric

BC Hydro plans the following activities over the next four years:

- Continue licencing requirements and proceed with construction of the Stave Falls Powerplant Replacement Project for in-service in 1999.
- Continue the Environmental Assessment Act licencing process for:
  – Revelstoke Unit 5 Project for earliest in-service in 1999.
  – Seven Mile Unit 4 Project for in-service in 2000.
  – Continue with Resource Smart efficiency improvement projects where they are cost-effective and help to meet Corporate objectives.

8.2.2.3 Thermal

It is important to put some perspective on the repowering options for the six unit, 900 MW Burrard Thermal Generating Station. These options would comprise the installation of the latest technology of combined cycle combustion turbines at the plant. Although the results of this Plan indicate that these options could have cost, rate and environmental benefits, the studies are based on current knowledge of emerging technology. The potential cost advantages, higher efficiencies and air emissions improvements, together with the issue of availability and price of natural gas would require detailed investigation, evaluation and public consultation before specific commitments for repowering can be made.

With this in mind, BC Hydro foresees the following work at the Burrard Thermal Generating Station over the next four years:

- Monitor the performance of selective catalytic reduction air emission control technology installed on Unit 5 in 1995.
- Install selective catalytic reduction air emission control technology on Unit 4 for in-service in 1996.
- Continue life extension work on Units 4 and 5 and common facilities of the plant.
- Continue investigations to secure firm transportation of natural gas to the plant from the Huntingdon natural gas market hub near Sumas for earliest in-service.
- Continue the investigation of repowering two modules (which may result in an Environmental Assessment Act Application) as follows:

1 In the future, alternative technologies considered in this Plan may be cost effective. Maintaining an information base will provide an indication of when these technologies will be cost effective to implement. This provides further opportunities to implement the options or to ensure identification of the exposure to loss of market share if the technologies are implemented by customers or third parties.

– Retire Unit 6 and install first combined cycle combustion turbine module for earliest in-service[2].

– Retire Unit 1 and install second combined cycle combustion turbine module for earliest in-service[3].

– If the first and second modules of combined cycle proceed, the work would be carried out in a manner as to physically allow future installation of a third and a fourth module.

8.2.2.4 Purchases

The following electricity purchase activities are planned over the next four years:

- Continue working with the Province of British Columbia and Alcan on an agreement for delivery of the existing surplus from the Kemano 1 Project. Current purchases from Alcan are about 1,750 GWh per year. Long-term purchases could be about 1,225 GWh per year.
- Continue working with the Province of British Columbia to help the Government maximize the value of the Canadian Entitlement to the Columbia River Treaty downstream benefits. Since the Province of British Columbia owns the downstream benefits and could sell them to parties other than BC Hydro, they are not included in the 20-Year Outlook; however, BC Hydro is retaining flexibility to possibly purchase a portion of the downstream benefits in a manner that meets Corporate objectives.
- Continue economic purchases from Alberta and the United States.

8.2.2.5 Private Sector

BC Hydro prepared a short list of 10 proposals (Table 8.2) from the 48 received in response to its December 1994 *Request for Proposals for Supply of Electricity for the BC Hydro Integrated System*.

The following actions are planned:

- Proponents on the short-list will be given an opportunity to improve their bids and provide further detailed information on attributes of importance such as economic and environmental impacts. BC Hydro may then select from the short list a number of proponents for further negotiations, possibly leading to agreement(s) for electricity purchase.
- BC Hydro may acquire up to 300 MW of electricity from one or more of the proposals on the short list. The amount will depend on price and contract negotiations. Proponents are responsible for consulting with stakeholders and gaining regulatory approval.

In the future, BC Hydro will continue to assess opportunities to purchase electricity from independent power producers.

8.2.3 Demand Side

8.2.3.1 Demand-Side Management (Power Smart)

Demand-side management activities over the next four years include continuing with current program activities[4] in the short term, recognizing that a change towards more competition may require a transition to fee-for-service and cost-recovery programs. The programs could be smoothly transformed from including incentives and rebates to the provision of energy efficiency customer services on a cost-sharing and cost-recovery basis. These re-designed programs would continue to be justified on an individual basis. Further details on these changes will be made available as they are developed.

2 The estimated time required to licence, procure and construct the first module is at least two years following detailed investigation of financial, technical and environmental issues.
3 It is expected subsequent modules could be constructed one year apart, if required. For construction, existing unit(s) would be retired one year prior to the in-service date(s) of the replacement module(s).
4 Based on the *Draft 1995 Demand-Side Management Plan.*

Table 8.2:

Short List from December 1994 Request for Proposals

PROJECT NAME	PROPONENT'S NAME	SIZE (MW)	FUEL TYPE	LOCATION
AES Fraser Valley	AES Transpower Inc.	337	natural gas	Abbotsford
Ashlu Creek	Ledcor/North Pacific Power Corp.	45	hydroelectric	20 km.north of Squamish
Harmac Cogeneration	Harmac Pacific Inc.	28	wood-residue/ natural gas	Nanaimo
Intercon Wood Residue Cogeneration	Canadian Forest Products	45	wood residue	Prince George
Island Cogeneration	Fletcher Challenge, Westcoast Power	240	natural gas	Campbell River
Kokish River	Northern Utilities Inc.	35	hydroelectric	17 km.southeast of Port McNeil
Pingston Creek	Canadian Hydro Developers (BC) Inc.	20	hydroelectric	80 km.south of Revelstoke
Port Alberni Cogeneration	CU Power Int.,Pan Canadian, MacMillan Bloedel	240	natural gas	Port Alberni
Purcell Power	Stothert Power Corp.	10	wood residue	Skookumchuck
Zeballos	Island Power Corp.	16	hydroelectric	10 km.north of Zeballos

The possible future transition of demand-side management from provision of rebates to value-added customer services could result in more (or less) energy savings, depending on how customers respond to the new approach. Further development of a transition strategy and continued monitoring of program performance are required. The effects are likely to be within the range of the demand scenarios considered, therefore similar rescheduling of resources would be undertaken as discussed in Section 8.4.2.

8.2.3.2 Community Energy Planning

The following community energy planning activities are planned over the next four years:

- Develop a business case for approval to ensure community energy planning activities contribute to Corporate objectives.
- If a program is approved, increase contacts with customers, businesses, municipalities and regional districts to involve these groups in the consideration of energy and electricity implications of land-use planning and community development.

8.2.3.3 Rates

BC Hydro's short-term industrial rate unbundling initiative will be implemented in late 1995 as follows:

- Wholesale wheeling rates, a requirement for membership in regional transmission groups,[5] will be filed 13 November 1995.
- An alternative to the existing Power Exchange Operation will be reviewed in conjunction with the Industrial Service Options.
- The revised Industrial Service Options package, which is scheduled to be filed 15 December 1995 following consultation with industrial customers, will likely make incremental and complementary services available to transmission customers. The options being considered include standby, real-time pricing, time-of-use and curtailable rates.
- BC Hydro also intends to file an application by 15 December 1995 to ensure recovery of full costs of billed services. As a separate filing on 11 September 1995 (for a BCUC review of extension policies), BC Hydro proposed a modification of its Standard Charges.

As part of a longer-term unbundling initiative for all customers, BC Hydro plans to redefine services, identify costs and repackage services with associated pricing to provide more service and product choices[6]. These rate development actions are tied to the rate strategy discussed in Chapter 7. These actions will be revised as the rate strategy evolves to adapt to changing customer needs and electricity market outlook.

8.2.4 Transmission

There is a need to provide flexibility in the transmission plan to respond to changes in demand, generation plans and project implementation delays. To reinforce the interior to Lower Mainland and Vancouver Island transmission system, and to retain flexibility, the following activities are planned over the next four years:

- Proceed with planning, design and installation activities to uprate the American Creek Series Capacitor station for in-service as early as 1999.
- Continue planning activities to ensure the availability of rights-of-way for a second Nicola to Meridian (Merritt to Coquitlam) 500 kV transmission line in the future.
- Continue with regional electricity planning for supply to Vancouver Island including investigation of generation and demand-side alternatives on the Island.
- Continue planning and investigation of transmission alternatives including a seventh 500 kV cable from Malaspina to Dunsmuir (Sunshine Coast to Qualicum) for in-service as early as 2002. Also, plan for the associated advancement of the Dunsmuir to Sahtlam (Qualicum to Duncan) transmission system upgrade, including conversion of the Dunsmuir to Sahtlam lines to 500 kV (from 230 kV) for in-service as early as 2002 and looping one of the Dunsmuir to Sahtlam lines into a new 500 kV station in the Nanaimo area for in-service as early as 2006. The timing and need for these projects will depend on the results of the regional electricity planning studies.
- Proceed with planning, design and implementation of Distribution Automation, specifically its voltage and reactive power optimization functions, for peak load reduction on Vancouver Island.

8.2.5 Comparison with Consultative Committee Recommendations

A significant portion of BC Hydro's Four-Year Action Plan is supported by the Consultative Committee as demonstrated in Table 8.3.

5 BC Hydro recently joined the Western Regional Transmission Association and Northwest Regional Transmission Association.
6 Rate options that could be further considered include: connection fees tied to efficiency and use pattern of customer facilities; green rate for the purchase of alternative (renewable) technologies; a net billing structure that would permit residential and general self-generators to sell surplus to BC Hydro at wholesale prices; real-time pricing; regional rates; seasonal rates; and others.

Table 8.3:

Comparison of the Action Plan to the Consultative Committee Recommended Portfolio (with Subsets F1 and F2) Based on a Four-Year Outlook

ACTION PLAN (I)	COMMON ELEMENTS OF THE CONSULTATIVE COMMITTEE'S PORTFOLIO RECOMMENDATION (FOUR-YEAR OUTLOOK)	
Revelstoke Unit 5	Revelstoke Unit 5	
Stave Falls Powerplant Replacement	Stave Falls Powerplant Replacement (ii) and (iii)	
Seven Mile Unit 4	Seven Mile Unit 4	
Resource Smart	Resource Smart	
Burrard Thermal Plant: Repower two modules	Burrard Thermal Plant:Repower up to three modules.	
Community Energy Planning	Community Energy Planning	
Further investigate rate options of interest.	Further investigate rate options of interest.	
Demand-Side Management: Programs passing ratepayer impact measure (RIM) test.	Demand-Side Management: Programs passing ratepayer impact measure (RIM) test.	
	Portfolio Subset F1	Portfolio Subset F2
Additional programs from *Draft 1995 Demand-Side Management Plan*, with transition strategy.	No demand-side management beyond ratepayer impact measure.	*Draft 1995 Demand-Side Management Plan* plus achievable potential identified in the Conservation Potential Review Phase II.
Collect information on alternative technologies.	No alternative technologies.	Alternative technologies,including installed capacity of 40 MW of wind,10 MW of solar photo-voltaic and 2 MW of fuel cells.
Other resources (any technology):as required to meet energy and capacity requirements,in least cost order.	Other resources (any technology) as required to meet energy and capacity requirements, in least cost order	Other resources as required to meet energy and capacity requirements,with preference to small and medium hydroelectric projects.

(I) Projects and programs for which investigations or implementation are planned.
(ii) A majority of Consultative Committee members requested independent verification of the estimated $53 million in avoided costs from retiring the Stave Falls powerplant and wished to ensure there is a forum for addressing environmental questions about the project,particularly its impact on potential rehabilitation of fish habitat in the Alouette River.
(iii)In the analysis underlying the *1995 Integrated Electricity Plan*, the estimated avoided retirement and decommissioning costs have not been credited to the project.

8.3 Links to the *Strategic Business Plan*

The purpose of the *Strategic Business Plan* is to establish a vision for the Corporation which encompasses the Corporation's mission and philosophy. The *Strategic Business Plan* is a working document that sets measurable strategic objectives that take into account the current and emerging external factors which will impact the Corporation and its business. The *Strategic Business Plan* shows planned capital and operating, maintenance and administrative (OMA) expenses for BC Hydro for the current fiscal year and the following three fiscal years.

This Action Plan will result in changes to some portions of future capital and OMAexpenditures planned by BC Hydro's strategic business units[7]. In particular, changes in planned generation and bulk transmission projects will be reflected in the "Power Supply" and "Transmission and Distribution" sections of the next *Electric System Plans and Evaluations*; the proposed changes are documented in Appendix G.

The demand-side management programs identified in the Action Plan will form the basis of the Customer Services deferred capital and OMA designated for demand-side management. The deferred capital designated for demand-side management is currently forecast at $49 million for 1995/96 and $45 million per year for 1996/97 through 1998/99.

The proposed changes to the Power Supply, Transmission and Distribution and Customer Services capital and OMA will be reflected in the next *Strategic Business Plan*.

8.4 Strategies to Address Risks and Uncertainties

8.4.1 Introduction

Factors outside BC Hydro's control affect electricity demand, supply costs (e.g., natural gas price), project licencing, project availability and environmental regulation. BC Hydro's response to changes in these external factors affects its ability to meet its Corporate and planning objectives. For example, if BC Hydro's share of demand for electricity does not increase as forecast and projects continue to be built as planned, over supply of electricity could result. This could necessitate sales of surplus electricity at uncertain prices, possibly resulting in poorer financial performance than if projects were delayed in response to reduced demand growth.

In order to assess what actions should be taken to respond to or prepare for changing external circumstances, several scenarios were developed as discussed in Chapter 7. These scenarios consider various levels of demand, various gas prices, reduced availability of hydroelectricity and resource availability. BC Hydro's selected portfolio and the Consultative Committee's recommended portfolio and subsets were studied under these scenarios. These scenario analyses are the basis for identifying and justifying the risk mitigation strategies and tactics discussed below. These actions are intended to be proactive in responding to changing external conditions to ensure the Plan is robust and flexible.

In some cases, different risks require opposite responses and therefore there is not one group of strategies that will cover all situations. This leads to a strategy to balance the exposure to each scenario.

7 BC Hydro's Strategic Business Units are: Power Supply; Transmission and Distribution; Customer Services; Corporate and Financial Affairs; and Human Resources, Aboriginal Relations and Environment.

8.4.2 Demand

8.4.2.1 Rationale

BC Hydro's share of future demand for electricity sets the amount of new resources required in the future. If demand growth is higher than expected, electricity may be in short supply, possibly requiring purchases of electricity at higher short-term prices. If demand growth is lower than expected, surplus electricity may be sold, but uncertain prices could hamper BC Hydro's financial performance.

The risk of future demand not matching the demand forecast is significant. Customer self-generation, wholesale transmission access and potential future retail transmission access point to lower demand. On the other hand, wholesale access could provide additional opportunities for BC Hydro that could increase demand.

One way to reapportion the uncertainty of future demand is to move to shorter-term contracts for electricity purchases. This would result in the supplier taking on more of the risk of future demand. Amove to shorter-term contracts is likely as purchasers are demanding greater flexibility.

8.4.2.2 High Demand

If the "High Demand Scenario" discussed in Chapter 7 occurs in the future, possible actions to minimize BC Hydro's exposure to high costs and under supply include:

SHORT TERM

- Increase cost-effective imports from Alberta and the United States.
- Increase demand-side management activities designed to reduce demand.
- Accelerate the development of rate options to influence demand.
- Ensure planned projects meet in-service dates[8].

MEDIUM TERM

- Accelerate private sector and BC Hydro projects to achieve earlier in-service dates. This could include:
  – Advancing future requests for proposals and acquisitions for supply of electricity from the private sector.
  – Advancing the in-service date of repowering modules three and four at Burrard.

8.4.2.3 Low Demand

If the "Low Demand Scenario" discussed in Chapter 7 occurs in the future, possible actions to minimize BC Hydro's exposure to over supply include:

SHORT TERM

- Increase domestic and export marketing activities to increase market share.
- Reduce demand-side management activities designed to reduce demand.

MEDIUM TERM

- Defer private sector and BC Hydro projects to achieve later in-service dates. This could include:
  – Delaying future acquisitions from the private sector.
  – Delaying the in-service date of Burrard repowered modules three and four.

8.4.3 Natural Gas Prices

8.4.3.1 Rationale

An increasing share of future project additions is expected to be natural gas-fired. The price of natural gas is an important component of the cost of natural gas-fired electricity generation; i.e., high gas prices result in higher cost generation for natural gas-fired plants, low natural gas prices result in lower cost of generation for natural gas-fired plants. Actions proposed to respond to high and low natural gas price scenarios are discussed in the following sections.

8 For some projects,planning,and design can be advanced to 'shelf ready' to reduce the implementation time of the projects when a need is identified.

In addition to the actions discussed below to address high gas prices, hedges against future high gas prices could be considered. Possible gas price hedges include:

- Terms offered by some potential private sector (IPP) proponents.
- Purchasing financial instruments (natural gas futures).
- Purchasing natural gas wells.

Prior to considering gas price hedging options, investigation of exposure is required. An important consideration is the interactions between both natural gas prices and demand and electricity prices and demand. High retail natural gas prices relative to electricity prices would result in more customers choosing electricity over natural gas for end uses such as heating, hot water, cooking, industrial processes and other fuel-flexible end uses. Lower natural gas prices would have the opposite impact. Further study of the impact natural gas price and demand changes could have on BC Hydro is planned. This will assist in determining the extent to which natural gas price risk mitigation is needed.

8.4.3.2 High Natural Gas Prices

If the "High Natural Gas Price Scenario" discussed in Chapter 7 occurs in the future, possible actions to reduce BC Hydro's and its customers'exposure to higher electricity costs from natural gas-fired thermal plants include:

SHORT-TERM

- No action required[9].

MEDIUM-TERM

- Advance acquisition of non-gas-fired resources.

8.4.3.3 Low Natural Gas Prices

If the "Low Natural Gas Price Scenario" discussed in Chapter 7 occurs in the future, possible actions to reduce BC Hydro's overall cost of supplying electricity include:

SHORT-TERM

- No action.

MEDIUM-TERM

- Advance acquisition of gas-fired resources.[10]

8.4.4 Resource Availability

8.4.4.1 Alcan Purchase

Current purchases from Alcan are about 1,750 GWh per year. Long-term purchases could be about 1,225 GWh per year. If these purchases were not available to BC Hydro, possible actions include:

- Increase imports.
- Advance other resources as required.

8.4.4.2 Downstream Benefit Entitlements of the Columbia River Treaty

Although the 20-Year Outlook does not include purchase of the downstream benefits by BC Hydro, a scenario was studied to consider possible actions if a large portion (950 MW) of the downstream benefits became available for BC Hydro to purchase at a price competitive with other sources. Possible actions to minimize BC Hydro's exposure to oversupply include:

SHORT TERM

- Increase domestic and export marketing activities to increase market share.
- Reduce demand-side management activities that are designed to reduce demand.

9 The analysis in Chapter 7 demonstrates that including significant natural gas-fired generation (IPP and/or Burrard) in the Action Plan is robust to future gas price changes.

10 If required considering demand for electricity.

MEDIUM TERM

- Defer private sector and BC Hydro projects.

If the downstream benefits were to be returned to British Columbia, the return over existing transmission lines would be preferred. However, the default location specified in the Columbia River Treaty is the Canada/United States border near Oliver. If the downstream benefits are returned at Oliver possible actions include:

- Advance licencing, approval and construction of a new 500 kV substation near Oliver to tie into the 500 kV system between Selkirk (near Trail) and Nicola (near Merritt) and a 500 kV transmission line from the Canada/United States border to the new station.
- Depending on the corresponding resource portfolio, the availability of standby transmission service and the ability of reactive power options to meet transfer requirements, the licencing, approval and construction of a second Nicola to Meridian (Merritt to Coquitlam) 500 kV transmission line may be required.

8.4.5 Environmental Management and Regulation

8.4.5.1 Rationale

Environmental management and regulation can change the capability and costs of existing and planned facilities. Environmental management – interpretation and application of regulations and guidelines or self-regulation – may be as significant as the enacted regulations themselves. In some case, changes to environmental management and regulation could delay the licencing of projects or result in the inability to licence or operate a project. Part of the strategy to accommodate such changes is to diversify the resource mix with a portfolio of resources that has hydroelectric, wood residue, natural gas, demand-side management, purchases and private sector resources.[11] In addition, there may be opportunities to add capability at existing facilities with few negative environmental implications. This section describes how BC Hydro could change its resource selections to respond to future environmental management and regulation.[12]

8.4.5.2 Reduced Output of Hydroelectric System

The *Electric System Operations Review* (ESOR) identified environmental, social/community and economic development issues related to operations of BC Hydro's existing facilities and also considered operational changes[13] to address these issues[14]. Recommendations from the *Electric System Operations Review* are now being implemented.

Future changes in operations to achieve non-power benefits could reduce the capability of the existing system. As discussed in Chapter 7, a scenario was used to examine the impacts of possible changes. If the output of the existing system was reduced as examined in the scenario, possible actions include:

SHORT TERM

- Increase imports.

MEDIUM TERM

- Advance energy resources and defer capacity resources.

To reduce the risk of future operational changes, risk assessments and multiple account evaluations which consider the full range of impacts should be completed prior to project implementation.

11 And cost-effective alternative technologies in the future.
12 The following discussion focuses strictly on possible changes to resource acquisitions in response to environmental issues. BC Hydro is involved in numerous other initiatives and programs to address environmental concerns, including response to the Electric System Operations Review and compensation funds.
13 Some operational changes would reduce the capability of the electric system.
14 Other changes to operations, prior to the Electric System Operations Review, have also reduced the capability of the electric system.

8.4.5.3 Local Air Emission Regulation

Local air emissions are a concern in the Lower Mainland and Fraser Valley and other air sheds where air quality is occasionally poor. Future regulation (e.g., emission caps) may constrain the development of thermal resources in these air sheds. In addition, licencing and permitting could lead to delays in project implementation. Possible actions to reduce these risks include:

- Improve conversion efficiency of existing facilities (e.g., repower Burrard).
- Mitigate emissions with appropriate control technology.[15]
- Acquire thermal resources from outside the airsheds of concern.
- Acquire less thermal resources in stressed air sheds, recognizing that this may have transmission reinforcement consequences.
- Acquire non-thermal resources.
- Consider emissions offsets.[16]
- Consider local emissions trading (if available).
- Participate in the development of air quality management plans.

8.4.5.4 Greenhouse Gas Regulation

BC Hydro is currently preparing a greenhouse gas management strategy. The strategy is expected to set objectives while recognizing the need to consider electricity supply in the context of economic activity in general.

The uncertainties in the knowledge base make it difficult to assess the risks posed by anthropogenic (human impact on the environment) climate change. In making decisions, the following need to be taken into account: the inherent time lag between greenhouse gas emissions and climate response; the time lag between climate change and ecosystems' adaptability (and the potential irreversible impacts); the lead time for infrastructure turnover; and the lead time required for national and international political processes.

Taxes are a potential policy instrument to control greenhouse gas emissions. However, the use of taxes to alter market prices requires careful consideration in order to avoid market distortions and decreasing economic efficiency (which could negate the overall impact of climate change policies). This, combined with the current direction towards deregulated energy markets, decreases the probability that unilateral provincial or federal carbon or energy taxes will prevail.

A North American carbon or energy tax would likely improve BC Hydro's competitive position. This is due to the pre-dominance of hydroelectric resources in its system which have low or zero carbon intensity.

Possible resource selection strategies to minimize greenhouse gas emissions include:

- Improve conversion efficiency of existing facilities (e.g., repower Burrard).
- Reduce the amount of natural gas generation in favour of alternative technologies, hydroelectric generation, wood residue generation and demand-side management.
- Consider emissions offsets.
- Manage the allocation of risk of possible future greenhouse gas regulation requirements between BC Hydro and independent power producers.

BC Hydro will continue to participate in consultations initiated by Government and in voluntary programs led by Natural Resources Canada in association with the Canadian Electrical Association.

15 New thermal resources will likely be limited to 'best available control technology' and could be further limited to 'lowest available control technology'.

16 Offside emissions mitigation occurs when emissions from a given source are 'offset' by reducing emissions from other existing emission sources,rather than reducing emissions at source.

8.4.5.5 Land Use

Electricity generation and transmission choices are affected by land use and land ownership. These constraints could be mitigated in several ways:

- Include more local and distributed generation in the Plan to reduce transmission requirements.
- Identify potential land-use constraints and contingency options.
- Participate in local land-use planning activities so that municipalities are aware of the electricity infrastructure needs and consequences in their communities (see Section 8.2.3.2, “Community Energy Planning”).

Lands and rights associated with projects which have strategic importance[17] should be retained. These projects would enable BC Hydro to respond to future uncertainties such as the location of future demand growth and resources, delivery point of any downstream benefits, air emissions concerns and depletion of fossil fuels.

Many of the projects included in the 20-Year Outlook and Four-Year Action Plan could impact lands currently subject to Aboriginal land claims. Land claim issues may impact the licencing and lead times for projects identified in the Four-Year Action Plan. BC Hydro will continue to seek opportunities for appropriate consultation on electricity planning with Aboriginal peoples to better understand Aboriginal concerns and issues. In addition, appropriate consultation with Aboriginal peoples would be needed for specific projects that move forward from planning to implementation.

8.5 Summary

The Four-Year Action Plan is summarized on Table 8.4. These activities may change in the near future to adapt to changes in external factors and to changes in the electricity industry.

17 These include interior to Lower Mainland transmission line options, Lower Mainland to Vancouver Island transmission line options and some resource options.

Table 8.4:

Summary of Four-Year Action Plan

RESOURCES	ACTION	SCHEDULE
Generation (supply-side)		
Alternative Technologies	Continue to collect information,provide quarterly reports and annual updates of Resource Summaries.Support information exchange, research and demonstration projects if cost-effective.	Ongoing
Hydroelectric		
Stave Falls Powerplant	Continue licencing requirements and proceed with construction.	In-service 1999
Revelstoke Unit 5	Continue the Environmental Assessment Act licencing process.	Earliest in-service 1999
Seven Mile Unit 4	Continue the Environmental Assessment Act licencing process.	In-service 2000
Resource Smart	Continue cost-effective efficiency improvements at existing facilities.	Ongoing
Purchases		
Alberta Imports	Purchase when cost-effective and/or needed.	Ongoing
Alcan	Continue purchases.	Ongoing
Downstream Benefits	Continue discussions with the provincial government.	Ongoing
U.S.Imports	Purchase when cost-effective and/or needed.	Ongoing
Thermal		
Burrard Thermal	Install second selective catalytic reduction and associated upgrade work.	In-service 1996
	Continue investigation of repowering two modules.	Earliest in-service
	Continue full repowering investigations.	Future
	Continue investigations on fuel supply.	Underway
Private Sector		
December 1994 Request for Proposals	Negotiate with proponents for possible purchase of up to 300 MW if contract terms and pricing are satisfactory.	Underway
Demand-side		
Community Energy Planning	Involve municipal governments,planners,businesses and residents in energy aware community and land use planning.	Ongoing
Demand-Side Management	Continue current plans in the short term, recognizing that changes in the electricity market structure toward more competition may require a transition from rebates to fee for service and cost recovery.	Underway
Rates		
Wholesale Wheeling Rate	File wholesale wheeling rate.	By mid Nov. 1995
Industrial Service Options	Revise following consultation with industrial customers.	By late 1995
Power Exchange Operation	Review other alternatives.	By late 1995
Other Options	Continue to develop rate options and consult with customers on their rate options needs.	Underway
Transmission		
Interior to Lower Mainland		
American Creek Capacitor Station	Proceed with planning activities to uprate.	Underway
Second Nicola to Meridian 500 kV Transmission Line	Continue planning activities to ensure the availability of right-of-way to build a line, if required,in the future.	Underway
Supply to Vancouver Island		
Malaspina to Dunsmuir Seventh 500 kV cable	Continue investigation of seventh 500 kV cable.	Underway
Dunsmuir to Sahtlam Upgrade	Continue investigation to upgrade from 230 kV to 500 kV operation.	Underway
Distribution Automation	Continue cost-effective distribution automation.	Ongoing

Note:Capital budget implications for Power Supply and Transmission & Distribution to be reflected in the *Electric System Plans & Evaluations*. Deferred capital implications for Customer Services (demand-side management) to be reflected in the Customer Services plans.

9 Planning in Transition

9.1 Introduction

The *1995 Integrated Electricity Plan* presents a snapshot in time. It is also the product of a planning process that is in transition from several perspectives. First, the components of the work plan for this Plan differed from previous electricity planning processes. Examples include a request for proposals for private sector resources and the use of a more comprehensive trade-off analysis and portfolio development process. Asecond, related change is the role of the Consultative Committee in providing advice to BC Hydro on the development of the Plan. Third, the concept of restructuring in the electricity market has evolved significantly since this planning and consultation process was initiated in December 1994.

The experience gained by both BC Hydro and the Consultative Committee has provided valuable insights on how to make the process more effective. This chapter explores some of the issues and lessons learned in the development of the Plan. It provides an overview of some of the issues identified by BC Hydro and the Consultative Committee that will need to be addressed in future electricity planning processes, including specific recommendations made by the Consultative Committee on the planning process. The implications of the changing electricity market structure in British Columbia are also briefly discussed.

9.2 Issues and Lessons Learned

9.2.1 Public Consultation

The public consultation process centred around the participation of the Consultative Committee based on directives contained in the British Columbia Utilities Commission decision on BC Hydro's *1994/95 Revenue Requirements Application*. Consultative Committee members invested a substantial amount of time to provide advice to BC Hydro in the development of this Plan. In addition to the 24 full days of meetings which were held with the Consultative Committee, members spent significant time in travel and preparation for the meetings. The commitment of Consultative Committee members to the process and the advice they provided are recognized and valued.

Although the use of a focused stakeholder group (the Consultative Committee) to obtain input generally worked well from BC Hydro's perspective, the experience gained through the consultative process has helped to identify a number of issues for consideration in future planning processes.

- For future programs, time should be allocated to take into consideration the full scope of the work program and the commitment required by stakeholders and planning staff. The short time frame for the 1995 planning process strained the resources of both BC Hydro staff assigned to the development of the Plan and Consultative Committee members. Meetings of two full day duration were held every two weeks in the initial stages of the planning process, leaving little time for staff to carry out the planning work, or for Consultative Committee members to review materials in advance of discussion at the meetings.
- Representation of external stakeholders should be expanded to include, at the very least, participation from the aboriginal community, commercial customers, the Vancouver Island region and the Union of British Columbia Municipalities. The short time frame, the frequency of Consultative Committee meetings and the work requirements for members to participate effectively were barriers articulated by some organizations who declined to participate in the 1995 planning process.
- External communication and consultation activities could be enhanced by, for example, market research to test the objectives, priorities and values with the public and a broader array of stakeholder groups. Additional consultation activities could improve the product, recognizing that the costs of all public consultation endeavors must be balanced with the benefit gained.

- Opportunities exist to better integrate consultation processes for BC Hydro's planning, projects and operations. This is addressed in a separate report to be submitted to the British Columbia Utilities Commission on public consultation integration at BC Hydro.

Notwithstanding the challenges encountered and lessons learned, this process has provided insights into the role and value of public consultation for long term electricity planning. It has served to demonstrate that BC Hydro can work effectively with the public on development of its electricity plans, and that this relationship helps to create a better understanding of the issues, the planning process and the decisions that have been made.

9.2.2 Demand-Supply Outlook

The *Electric Load Forecast 1994/95-2014/15*, developed prior to the start of the integrated planning process, was used for this Plan. This precluded Consultative Committee input into the load forecast for this planning cycle. However, some Consultative Committee members participated in a one-day planning forum on the development of the 1995/96 forecast, and some members were also involved in a subsequent brainstorming session on load forecasting scenarios. Further opportunities for stakeholder input into the load forecast will be considered. Future discussions on the demand-supply outlook with external stakeholders could also address the reliability criteria used in planning.

9.2.3 Planning Objectives

In the development of the Plan's objectives, several Consultative Committee members were not able to easily identify the relationship between objectives and subsequent steps in the process, such as resource characterization or trade-off analysis. As a result, some objectives were identified that, in retrospect, did not contribute to the planning process and the selection of resources. In the future, the linkage between the objectives and subsequent steps in the planning process, especially attributes and portfolio resources, will need to be considered.

9.2.4 Identification and Characterization of Resource Options

LIST OF RESOURCE OPTIONS

The 1995 planning process included a preliminary screening to prioritize the options of greatest interest for characterization and to remove some resource options from consideration. More detailed screening was performed using the trade-off process, which required quantification of the trade-off attributes for all projects. Expanding the preliminary screening, based on well-defined criteria agreed to by stakeholders (internal and external), would reduce data collection needs while providing a defensible treatment of marginal resource options. Furthermore, experience gained in the 1995 planning process would assist in developing those criteria.

RESOURCE CHARACTERIZATION FRAMEWORK

The RCF provided a master list of attributes against which all resources were evaluated. The 1995 planning process developed this preliminary framework; however, further development of the specific attributes and measures is needed. Also, the applicability of the framework to data collection at the project level should be tested and its role in shaping the planning database confirmed.

TRADE-OFF ATTRIBUTES

The trade-off attributes used in this planning process may or may not carry forward to future planning processes, depending on the overall objectives of subsequent plans. However, several weaknesses with the attributes used in this Plan were identified that highlight the need for further development and data collection. As expressed by some Consultative Committee members, some environmental and social values lacked good attributes. Areas for immediate improvement or expansion include:

Biodiversity: The 1995 planning process used two separate attributes to try to capture the concept of biodiversity: species persistence and terrestrial ecosystems. As discussed in Section 5.3, this approach has its weaknesses. Developing and monitoring a broader measure of biodiversity would help bring environmental concerns more into the planning process. Such a measure, which was not available for this planning process, would incorporate impacts on species abundance and aquatic ecosystems, thereby addressing some of the specific limitations of the two-attribute approach.

Upstream impacts: Impacts associated with fuel supply were captured by a measure of upstream emissions of greenhouse gases, a proxy for an array of impacts on land, water, air and social resources. Further work would reconcile the role of this attribute within the context of electricity (as opposed to energy) planning and, if appropriate, develop a more accurate attribute.

Air emissions: The trade-off attribute for local air emissions currently weights emissions by population within a 100 km radius of the emissions source. However, a more accurate measure of potential health effects would incorporate local sensitivities and geography by airshed.

Social/community attributes: Land use (area lost) was the single attribute used to address a wide range of social/community issues. As identified in the RCF and suggested by the Plan’s objectives, other factors that are not well represented by land use can be of concern (e.g., noise and recreation impacts). Development of a broader social/community attribute(s) is warranted, especially as community concerns gain importance in resource use decisions.

RESOURCE CHARACTERIZATION

Portfolio analysis requires a standardized characterization of individual resource options. The 1995 planning process introduced a standardized information base of environmental, social/community and economic development criteria. Development of such a database presented several challenges. For example:

- the information needed to be quantified to enable explicit consideration against financial and other attributes; and
- a large number of resource options covering a wide range of resource types were included.

Furthermore, the primary sources of information were environmental assessments and impact studies completed at the project level. Although environmental assessment requirements generally provide a common framework across all project studies, the specifics of individual projects largely direct the review efforts and the type of data collected. Consequently, not all project assessments contained the same type or level of information.

Because the information base used for characterization was developed with a different focus, baseline data were not always available on a consistent basis for environmental and social criteria. Some members of the Consultative Committee expressed concern over this lack of data, and the consequent use of proxies and qualitative descriptions. As recognized by participants in the 1995 planning process, some of the missing data could only be collected through detailed impact assessments at the time of project licencing application. As noted above, the preliminary RCF developed in this planning process provides a mechanism to link project-and planning-level information and to gradually refine the planning level database.

Members of the Consultative Committee, in particular the representative of the Independent Power Association of British Columbia, emphasized that BC Hydro should evaluate independent power projects on the same basis as it evaluates its own projects. The resource characterization completed for the 1995 Plan did follow this principle by using a consistent set of criteria (resource characterization framework and trade-off attributes) to determine and evaluate all resource options.

Resource Summaries, were prepared to provide information on individual resource otions. Although the Consultative Committee received draft copies of Resource Summaries, which also documented the data used in portfolio modeling, attempts should be made in future to distribute this data earlier to allow more time for stakeholders to examine and discuss the data and underlying assumptions. This would provide greater insight to the portfolio development and selection process. For example, questions related to economic and financial assumptions used in the portfolio evaluation and trade-off process (i.e., on depreciation periods, debt-equity ratios, the discount rate, cost of capital and economic life of projects) were analyzed[1] but not reviewed in detail with the Consultative Committee.

9.2.5 Portfolio De velopment and Evaluation

The portfolio development and trade-off analysis process occurred over a five month period and consumed much of the time available for Consultative Committee discussions. Some members of the Consultative Committee expressed concerns about the need for multi-attribute trade-off analysis and the complexity of the model used in the portfolio development process. A related concern was the need for additional time to prepare information so that it could be more easily interpreted and assimilated by Consultative Committee members, and for exploring specific issues in more depth.

9.3 Consultative Committee Recommendations

The Consultative Committee, at its meeting on August 17 and 18, identified consensus recommendations or statements pertaining to future integrated electricity planning by BC Hydro. These unedited recommendations and statements are presented below:

GREENHOUSE GAS EMISSIONS

"The lack of clarity as to requirements in relation to 1990 greenhouse gas levels creates uncertainty for planning. Some members wished to recommend that BC Hydro, in consultation with Government, set greenhouse gas targets for itself."

TRANSMISSION AND DISTRIBUTION REQUIREMENTS

"BC Hydro should further pursue generation and load-management planning in relation to transmission and distribution requirements on a regional load requirement basis (regions within the province). The Consultative Committee has not had time to pursue this matter and recommends that it be pursued in the next integrated resource plan."

LOAD MANAGEMENT

"The next integrated resource plan should further examine load shaping options, including curtailable and dispatchable load management techniques and rate options."

ASSESSMENT OF PROJECTS

"BC Hydro should evaluate independent power projects and demand-side management programs on the same basis as it evaluates its own projects within the integrated resource planning process. For integrated resource planning to benefit British Columbia, all resources acquired by BC Hydro must be reviewed by an integrated resource planning process and appear in an approved integrated resource plan portfolio in order to be considered for construction. All projects must be required to undergo a full environmental assessment under applicable environmental assessment legislation."

1 See Appendix F for discussion of the impact that changes in these assumptions have on resource selection and portfolio performance.

DEMAND-SIDE MANAGEMENT

"The majority of Consultative Committee members recommend the next integrated resource plan identify and quantify more non-power benefits of demand-side management programs."

ALCAN

A majority of those Consultative Committee members choosing to participate in the recommendation requested that BC Hydro characterize three options with respect to purchases of power from Alcan in its resource inventory. The first two options below have been characterized; the third is requested to be added:

- *"BC Hydro purchases 140 MW from Alcan.*
- *Others purchase 140 MW from Alcan, and BC Hydro wheels the power.*
- *No one purchases the power and the water is returned to the Nechako River."*

9.4 The Changing Electricity Industry — Implications for Planning

The 1995 Integrated Electricity Plan has been developed during a period of uncertainty and transition in the electricity markets in British Columbia. In the past, uncertainties in electricity planning focused primarily on the level of future demand and the availability of various resources to meet that demand. Today, rapid changes in technology, global economies, open access competition, the environment and public interests are increasing the level of uncertainty associated with demand and resource availability.

Integrated electricity planning in the face of such uncertainty presents a major challenge to utilities, and BC Hydro is no exception. Planning is therefore best treated as a process of identifying strategies to respond to a variety of future conditions and taking the necessary steps to manage the implementation of options in a manner that does not prematurely commit resources. The following discussion identifies some of the implications of changing market conditions on planning for future electricity needs.

9.4.1 Electricity Generation

BC Hydro has traditionally been the primary provider of electricity, responsible for both generating and delivering electricity to customers. In recent years, new players have entered the generation markets. Utilities now have the option of developing their own resources or signing contracts with independent power producers to meet demand. These expanded options will increase the complexity of the electricity planning process, requiring consistent evaluation of a wider range of resources and careful assessments of investment risk and uncertainty.

9.4.2 Transmission

BC Hydro is responsible for delivering much of the electricity produced in British Columbia. This role is likely to continue for the foreseeable future, primarily because BC Hydro has a comprehensive network of transmission facilities in the province. There is, however, a trend towards open wholesale transmission access among utilities. Transmission facilities are beginning to function as 'common carriers' facilitating bulk power transactions between generation facilities in one jurisdiction and utilities in another.

BC Hydro has recently become involved in regional transmission groups (RTGs). RTGs are voluntary associations of transmission owners intended to facilitate the efficient use of existing transmission facilities, support competitive electricity trade, coordinate the planning of transmission system expansions and expedite the resolution of disputes concerning transmission services. Wholesale access will facilitate more competition among electricity generators and permit easier access by BC Hydro to resources outside its service area. As a result, BC Hydro will increasingly have to plan the transmission system to not only to meet its own needs, but also to meet third party needs (e.g., exports by independent power producers, wheeling transactions between neighbouring utilities).

9.4.3 Unbundling of Services

Traditionally, utilities have offered a limited range of bundled products and services for a given price. However, some customers, particularly at the industrial level, are demanding a wider variety of services and pricing options. In response to changing customer needs and expectations, utilities are beginning to unbundle their products and services. Service unbundling will further increase the complexity of electricity planning: integrated electricity planning will be conducted for a greater range of products and services, which will in turn influence the feasibility and desirability of different resource options. For example, resources may need to be differentiated by storage or transportation, not just energy and capacity. With an increase in product and service diversity, planning will also be required to better allocate costs among each component of service.

9.4.4 Retail Competition

In December 1994, the Provincial Government directed the British Columbia Utilities Commission to conduct a public review of electricity market structures in British Columbia to assist the government in developing electricity policy, particularly with respect to retail competition. The British Columbia Utilities Commission completed a series of formal hearings in June. At the time of writing, this plan, the report has been released for comment.

Although the implications of the electricity market review (EMR) still need to be assessed, the *Electricity Market Review Report* suggests that there is no compelling reason to introduce retail competition. BC Hydro does compete with self-generation and other fuels at the retail level.[2] Consumers also have the option to reduce electricity consumption through conservation or the use of more efficient technologies.

9.5 Summary

Changes in the electricity market structure will place greater pressure on BC Hydro to ensure that resource options are cost-effective and minimize risk and uncertainty. Investments which significantly raise rates may, in some cases, result in increased self generation, fuel switching or reduced electricity consumption, further increasing rates to remaining users. If this causes a further reduction in sales, the utility faces the possibility of stranded investments. Hence, there is increasing pressure to make sure that rates match actual costs of serving customers, and moreover, that costs are minimized.

From a planning perspective, this brief reflection on potential changes in the electricity market structure suggests a growing level of uncertainty. Electricity planners must now consider not only the availability of utility-owned resource options, but also independent power producer options and the implications of open access on the transmission system. Demand for a wider variety of products and services means that electricity planning must become more customer focused to respond to direct retail competition among alternative electricity suppliers should retail markets eventually be deregulated. These, and other issues and changes in the market structure, will be addressed in future electricity planning processes.

FUTURE PLANNING FOR ELECTRICITY RESOURCES WILL NEED TO CONSIDER:

- *greater competition in wholesale generation markets and increased competition and reliance on independent power producers (IPPs);*
- *the introduction of open transmission access to facilitate wholesale competition;*
- *greater diversification and flexibility in customer service options;*
- *unbundling of the commodity, delivery and customer service components of electricity service;*
- *customer demand for a greater range of products and services.*
- *the possible introduction of retail competition with respect to the provision of the electricity commodity component of electricity service.*

2 For example, large industrial customers have the option of generating their own electricity (i.e., self generation). The evolution of smaller-scale generating technologies is bringing self generation within the reach of even more customers, and the availability of other fuel sources (e.g., gas, oil) for heating has competed with electricity for years.

GLOSSARY

Annual Allowable Cut (AAC):
The rate of timber harvesting on Crown land specified by the B.C. Ministry of Forests.

Alternative Technologies:
Non-conventional electricity generating methods involving fuel cells, tidal, solar, wind and wave energy sources.

Augmented Generation:
Generation additions at existing facilities.

Attributes:
Factors describing certain characteristics of resources (e.g., greenhouse gas emissions measured in tonnes of CO_2).

Avoided Cost:
The unit cost of acquiring the next resource to meet demand. This is used as a measure for evaluating individual demand-side and supply-side options.

Basin:
The catchment area, drainage area or watershed of a river.

Beehive Burners:
Incinerators with a metal screen for emission control used in the forest industry to burn wood residue.

Canadian Entitlement:
The Canadian portion of the Columbia River Treaty downstream energy and capacity benefits resulting from increased electricity generation on the Columbia River in the United States due to the construction of Duncan, Keenleyside and Mica storage dams. See also Downstream Benefits (DSBs).

Capacity:
The rated power output (normally measured in kilowatts (kW) or megawatts (MW)) of a machine or power plant, or a transmission line's ability to transmit electricity, at any instant. Several related terms are commonly used:

Maximum:	The highest output that can be achieved.
Nameplate:	The maximum output identified by the manufacturer under specified conditions.
Dependable:	The maximum output that can be reliably supplied coincident with the system peak load.
Firm:	The maximum output based on the dependable capacity, unit availability and system characteristics.

Capacity Factor:
The ratio of the average annual power output to the rated power output of generating plants.

Characterization:
Describes features or characteristics of a resource according to attributes specified for the Plan.

Circuit:
Generally refers to specific three-phase transmission lines, submarine cables and underground cables, or a combination of these, operating as one element.

Cogeneration:
The production of electricity and useful steam for an industrial process from a single fuel source.

Columbia River Treaty:
A treaty between Canada and the United States which enabled storage reservoirs to be built and operated in British Columbia to regulate Columbia River flows to the United States, for shared power benefits and flood control.

Combined Cycle Combustion Turbine (CCCT):
The combination of combustion and steam turbines to generate electricity from two thermodynamic cycles. The exhaust gases from the combustion turbine are directed to a heat recovery steam generator which produces steam to power a steam turbine. This results in a higher thermal efficiency than when combustion or steam turbines are operated individually.

Community Energy Planning:
The integration of energy planning and community planning to provide energy and infrastructure savings for both utilities and communities.

Conservation:
A reduction in energy consumption, without a reduction in service level, achieved by changes in consumer behaviour such as turning off unnecessary lights or by improvements in end-use technology such as more efficient lights. See also Efficiency or Demand Side Management.

Consultative Committee:
A group of stakeholders brought together to provide advice to BC Hydro on the development of the *1995 Integrated Electricity Plan.*

Coordination:
Agreements between electrical system operators to pool resources and/or loads allowing more efficient operation, an increase in total firm energy from existing generating plants and/or deferral of resource acquisitions and improved system reliability.

Corporate Costs:
The financial cost to BC Hydro of undertaking a project, including transfer payments to Government.

Cost of New Electricity Supply:
The expected cost of obtaining new firm energy and capacity supply.

Critical Period:
A five-year period of record low stream flows. Critical water conditions serve as a design test of the capability of a hydroelectric system to meet the load forecast under adverse reservoir inflows. During a critical period hydroelectric reservoirs would be drawn down to minimum levels in order to sustain service. See also Secondary Energy.

Curtailable Load:
A load reduction rate option in which customers agree to a partial or complete power shut off during peak load periods or certain abnormal system conditions (for system security) in exchange for lower electricity rates. This option is more suitable for customers with flexible operations or back-up energy sources.

Decommission:
To take a power facility permanently out of service.

Demand:
The amount of electricity required by customers prior to adjustment for demand-side management programs.

Demand-Side Mana gement (DSM):
Actions that modify customer demand for electricity. These actions can defer the requirement for new energy and capacity supply additions.

Developed Rivers:
Rivers whose flows have been harnessed for the generation of hydroelectric power.

Discount Rate:
The rate used to value expenses and revenues which occur over different time periods. It is equivalent to the rate of interest net of inflation and represents the time value of money.

Distributed Generation:
Electricity generation, usually on a small scale, which is located throughout the electrical distribution system, usually closer to load centres or customers.

Distribution Automation:
Automatic control schemes applied to distribution systems, with various functions, e.g., to control distribution voltage, to regulate load for energy conservation and for peak demand reduction.

Distribution System:
Electrical lines, cables, transformers and switches used to distribute electricity over short distances from substations to the customer. The distribution system voltage is generally less than 60 kV.

Diversity
One of 12 trade-off attributes used for the integrated electricity planning process, defined as the measure of the number and type of different resources. Diversity increases as more resources and resource types are added to the BC Hydro system.

Downstream Benefits (DSBs):
The additional power benefits generated in the United States as a result of the Duncan, Keenleyside and Mica storage projects which were built in Canada under the terms of the Columbia River Treaty. See also Canadian Entitlement.

Efficiency:
The effective rate of conversion of a natural resource (e.g., natural gas) to useable energy and capacity or the effective rate of conversion of electricity to an end use (e.g., heating).

Electric and Magnetic Fields (EMF):
Electric and Magnetic Fields refers to both electric fields (EF), which are produced by the presence of a charge or voltage on an object, and magnetic fields (MF) which are produced by the flow of electric current through an object such as a transmission line. See also Electric Fields and Magnetic Fields.

Electric Fields (EF):
The lines of force that repel or attract an electric charge. Electric fields are produced by the presence of an electric charge or voltage on an object such as a transmission line. They are not influenced by the amount of electric current flow through the object. Electric fields are measured in units of volts per meter (V/m).

Electro-Mechanical Stability:
The condition of operation of an AC electrical system based on all generators operating in synchronism, that is, at the same "electrical" speed and in-phase with each other and able to withstand normal disturbances that could otherwise cause instability. The instability can occur within a fraction of a second or minutes. It can result in the electrical breakup of the transmission system into several sections and a widespread interruption of the electrical load or blackouts.

Emission Offset:
Reducing total pollution releases (emissions) by decreasing emissions from other existing sources rather than the source in question. For example reducing emissions from automobiles could be an emission offset for a thermal generation plant.

Energy:
The amount of electricity produced or used over a period of time, usually measured in kWh or GWh.

Energy Capability:
: The assured amount of energy that a generating plant can produce in a given time period (usually one year).

Externalities:
: The impacts of electric power generation on other activities or resources that are not priced in the marketplace such as the environment, human health or recreational sites.

Firm Export:
: The assured sale of a contracted amount of energy and/or capacity to utilities or customers located outside the boundaries of BC Hydro's service area.

Firm Gas Contract:
: An assured contract to supply or purchase a specified volume of gas at a fixed price.

Flat Rate:
: A pricing structure for electricity characterized by a single price for all levels of electricity consumption.

Generation:
: The production of electricity.

Green Field Site:
: An undeveloped site.

Greenhouse Gases (GHG):
: Gases which contribute to global climate change or the 'Greenhouse Effect'. These include carbon dioxide (CO_2), carbon monoxide (CO) and methane.

Gross Domestic Product (GDP):
: A measure of total economic activity within a region (e.g., the province) as calculated by the sum of all goods produced in a given period of time, usually one year.

Head:
: The vertical distance between the water levels immediately upstream and downstream of a turbine or discharge structure. The head represents the potential energy of the water which can be used to generate electricity as the water falls to the lower elevation.

High Voltage Direct Current (HVDC):
: Direct (non-alternating) current transmission at high voltages such as 260 kV. Direct current transmission lines generally use two conductors, as compared with the three used in three-phase alternating current (AC) transmission.

Hydroelectric Generation:
: Production of electricity through the use of turbines to extract energy from flowing water.

Independent Power Producer (IPP):
: The operation of a privately owned electricity generating facility which is usually connected to a utility's transmission system to sell electricity.

Industrial Service Options:
: The various rate structures that can be selected by industrial customers depending on their supply requirements.

Integrated Resource Planning (IRP):
: A planning process which involves stakeholders in evaluating a wide range of supply-side and demand-side options to determine the most appropriate mix of resources to reliably meet future electricity requirements.

Integrated System:
: The interconnected network of transmission lines, distribution lines and substations linking generating stations to one another and to customers throughout the BC Hydro electric system.

Interruptible Energy:
: A supply of electricity which is subject to short- or long-term discontinuation with or without notice.

Intra-Class Rate Options:
: Rate options available to a class of customer (e.g., industrial or residential).

Load:
: The amount of electricity required by a customer or group of customers as measured by an electrical meter.

Load Displacement:
: The reduction of electricity requirements from existing customers by using electricity more efficiently or by the addition of customer self-generation.

Load Factor:
: The ratio of the average load supplied during a given period to the maximum load occurring during the same period.

Load Forecast:
: The expected customer electricity requirements that will have to be met by the electrical system in future years.

Losses (Line, Transmission):
: Energy lost as heat in electrical equipment and along transmission lines due to resistance as electricity is transferred from one location to another.

Magnetic Field (MF):
: The lines of force that attract ferromagnetic materials (e.g., iron, steel, nickel). Magnetic fields (also referred to as electromagnetic fields) are produced by the flow of electric current through an object such as a transmission line. Magnetic field strength depends on the magnitude of the current flow in a transmission line. It is not influenced by the magnitude of the voltage on the transmission line. Magnetic fields are measured in units of gauss (G) or tesla (T) (10 G=1 mT).

Monetize:
To assign a monetary value to a social or environmental impact such as air emissions.

Multiple Account Evaluation (MAE):
A framework developed to facilitate identification and evaluation of financial, environmental, social and economic development impacts as part of a decision-making process.

Non-Integrated Areas:
BC Hydro service areas which are not connected to the integrated system. These areas are supplied by local hydroelectric generation or diesel generation.

Peak Demand:
The maximum instantaneous capacity demand experienced by a power system.

Portfolio:
A group of individual resources acquired in a sequence which meets the 20-year demand Forecast.

Present Value (PV):
Today's value of future expenditures (uninflated).

Power:
The instantaneous rate at which electrical energy is produced, transmitted or consumed, measured in kW or MW.
See also Capacity.

Powerex:
A BC Hydro subsidiary responsible for the purchase, sale and exchange of electricity between British Columbia, the western provinces and western United States. In addition, Powerex assists British Columbia industry and independent power producers in the electricity trade marketplace.

Power Transfer Capability:
The power that can be transferred over a particular section of a transmission system in a reliable manner.

Probable Demand Forecast:
The 20-year reference forecast modified to account for changes in demand attributed to expected rate changes (demand elasticity).

Probable Load Forecast:
The Probable Demand Forecast modified to account for expected savings from demand-side management programs.

Process Steam:
Steam used by industry for uses such as heating and chemical processes.

Pumped Storage:
The use of electricity generated during off-peak hours to pump water from a lower elevation reservoir to a higher reservoir. The stored water is then released during peak demand periods and used to turn a reversible pump/turbine generator before returning to the lower reservoir.

Purchases:
The acquisition of electricity from other utilities or independent power producers.

Rate Impact Measure (RIM):
A test of demand-side management programs to determine if the program would cause rates to increase.

Rates:
The price paid for electricity by BC Hydro's customers.

Reactive Power:
The component of power which gets interchanged between the source and reactive elements to establish magnetic and electrostatic fields. The energy associated with this component is zero. Reactive power is required for motor drives, fluorescent lighting and other end uses. Major sources of reactive power are generators and shunt capacitors. The unit of reactive power is VAR (volt-ampere reactive). See also Series Capacitors and Shunt Capacitors

Reactive Compensation:
Reactive compensation provides voltage support and control as well as increases the power transfer capability of the transmission system.

Reference Forecast:
The estimated 20-year forecast of electricity demand, excluding effects of demand elasticity and demand-side management programs.

Regional Equity:
The distribution of benefits and costs of the supply and use of electricity among the regions of British Columbia. Benefits and costs may be actual dollar payments, electricity service, changes in employment, impact on natural resources or a variety of other variables.

Regional Transmission Groups:
Voluntary organizations of transmission owners and users currently developing in the western US and Canada to facilitate wholesale transmission access.

Rehabilitation:
Upgrading or restoring the performance of an existing facility.

Reinforcement:
Improvements in the electrical system to maintain or increase reliability and security of supply.

Reliability:
A measure of the continuity and quality of electric service. Reliability of service to an individual customer depends on the reliability of generation, the high-voltage transmission system and the low-voltage distribution system.

Repower:
The replacement of gas-fired boilers with a heat-recovery steam generator that uses the waste heat from the exhaust gases of a gas-fired combustion turbine to produce the steam required to power a steam turbine.

Reservoir:
The body of water impounded behind a dam.

Resource:
Investments in facilities or expenditures in programs or purchases to meet electricity needs by providing new supply or changing the demand for electricity.

Resource Smart:
The name given to BC Hydro's strategy of improvements to existing power generation and transmission facilities to increase power output and efficiency.

Resource Acquisition Policy (RAP):
A screening tool based on multiple account evaluation which is used by BC Hydro to evaluate potential new resource acquisitions.

Resource Characterization Framework (RCF):
A set of attributes by which resources may be characterized and compared for planning purposes.

Reserve:
Additional generating capacity which is required to meet reliability criteria.

Rights-of-Way:
The land rights acquired by a utility to allow the construction and operation of electrical transmission or distribution facilities.

Scenario:
A set of assumptions used to test the long-term performance of a portfolio of resources.

Secondary Energy:
The additional energy that is available when stream flow exceeds critical conditions.

Sector:
The groups into which a utility's customers are generally divided, namely residential, commercial and industrial. The residential sector includes all single-metered dwellings occupied by customers and used as residences. The commercial sector includes service industries such as retail, community, transportation, communications and construction. The industrial sector includes operations such as pulp and paper, wood products, mining, metals, coal, chemical and petroleum.

Selective Catalytic Reduction (SCR):
A method of reducing nitrogen oxide emissions by injecting ammonia into the exhaust gases from a thermal plant and passing these gases over a catalyst.

Self-Generation:
Generation of electricity by a customer for part or all of its own load requirements.

Sequence:
The order in which resources should be acquired to meet the demand growth.

Series Capacitors (Series Compensation):
A group of capacitors that are connected in-line with the transmission line conductors so that the current through the conductors must also pass through these capacitors. These capacitors reduce the effective impedance of the line and increase its transmission capacity. They are typically situated at mid-line.

Shunt Capacitors, Shunt Reactors (Shunt Compensation):
Capacitors and Reactors connected between line conductors, or station bus, and the ground. Shunt Capacitors are located in the transmission system as well as in the distribution system. They produce reactive power and help to raise system voltages and consequently increase the transmission capacity of the system. Shunt Reactors are located in the transmission system. They absorb reactive power and help to reduce over voltages in the system.

Simple-Cycle Combustion Turbine (SCCT):
A stand-alone combustion turbine, similar to a jet engine, connected to an electrical generator and used for power generation.

Social Costing:
An approach which incorporates environmental and societal values in decision-making.

Stakeholder:
An individual or organization who has an interest in a BC Hydro project or issue.

Substation:
An electrical facility where transmission and/or distribution lines from various locations and at various voltage levels are connected by means of switches, transformers and other equipment.

Sub-transmission:
Transmission lines of 230 kV or less and higher than 25 kV. Sub-transmission lines generally supply regional loads.

Supply-Side Resources:
Options that supply additional electricity, including new generation projects, coordination and purchases and improvements to existing facilities.

Surplus Energy:
Energy in excess of demand.

Switching Stations:
A station with provision for changing the way in which transmission lines or generators are connected.

System Cost:
The present value (PV) of system cost is a measure of economic efficiency. It measures the total cost, in present value terms, of an initiative or project to the people of the province.

System Stability:
The ability of all parts of an electrical system to remain synchronized following an electrical disturbance such as the interruption of a transmission line.

Terrestrial Ecosystems:
One of 12 trade-off attributes used for the integrated electricity planning process, defined as the potential loss of sensitive ecosystems such as old growth forests, grasslands, and wetlands.

Thermal:
Refers to the production of electricity through a combustion process.

Thermal Ratings:
The maximum amount of power that can pass through a piece of electrical equipment without causing damage due to overheating. In the case of transmission lines, the heating due to excessive power transfer may cause a line to sag below safe ground clearance and conductor damage.

Time-of-Use Pricing:
Variable pricing of electricity where the price depends on the time of day: typically higher prices are charged during periods of high demand.

Trade-Off Attribute:
Highlights and combinations of the attributes in the Resource Characterization Framework which provide criteria to compare resource portfolios. Trade-off attributes reflect broad strategic and planning level issues.

Transfer Payments:
Payments to the Government including water rental fees paid on hydroelectric generation; provincial sales tax; corporate capital tax; municipal, property and school taxes; grants in lieu of taxes, as established by the Province; and motor fuel tax. Natural gas royalties are not considered a tax.

Transformer:
An electrical device for changing electricity from one voltage to another.

Transmission System:
Electrical facilities used to transmit electricity over long distances at voltages greater than 230 kV (bulk electricity).

Unbundling:
The disaggregation of electricity services currently provided as a whole into specialized services (e.g., transmission, distribution, generation, etc.).

Undeveloped Rivers:
Rivers whose flows are currently unaffected by any storage or generation facilities.

Upgrade:
An improvement to an existing facility.

Upstream Air Emissions:
One of 12 trade-off attributes used for the integrated electricity planning process, defined as air emissions not produced directly by BC Hydro generation but produced by a supplier providing product to a generation facility (e.g., emissions from a natural gas processing plant producing the gas to be supplied to power an electricity generating station).

Voltage Collapse:
A catastrophic drop in voltage in a region where the generation, transmission and distribution systems are incapable of supplying the load. A system enters a state of voltage collapse or instability when an increase in load, system disturbance or change causes voltage to drop quickly or drift downward, and automatic and manual system controls are unable to halt the decay. Voltage decay may take anywhere from a few seconds to minutes.

Voltage Stability:
The ability of the electrical transmission system to withstand the failure of a system element such as a line or transformer without causing voltage collapse at the receiving (customer) end of the system.

Wheeling:
The transmission of electric power from one system to another through a third party, usually the owner of the transmission facilities.
Retail Wheeling:
The wheeling of power from electricity suppliers to customers.
Wholesale Wheeling:
The wheeling of power from electricity suppliers to utilities.

Wood Residue:
The wood remaining after the processing of logs that has no marketable use as a lumber or pulp product. (Also known as wood waste.)