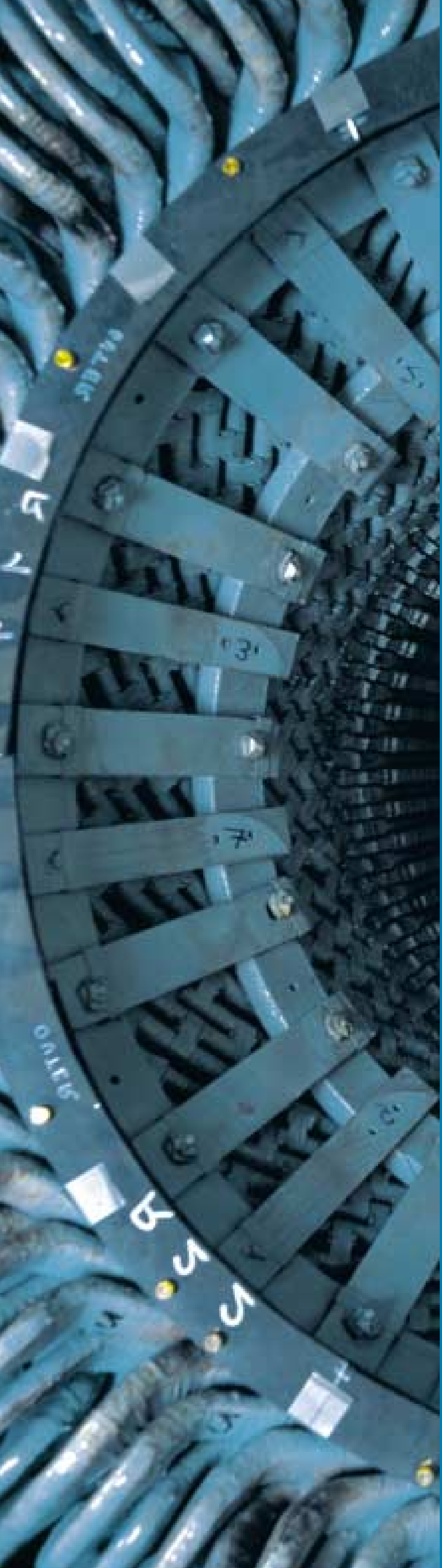
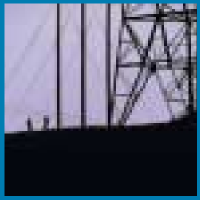


2004
Integrated Electricity Plan








Part 3 Resource Options

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Contents

Executive Summary

An integrated electricity plan (IEP) presents BC Hydro's long-term strategy for acquiring demand-side and supply-side resources to meet customer's future electricity needs and enable BC Hydro to meet its obligation to provide reliable electricity service to its customers at the lowest possible cost. This part of the 2004 IEP, Resource Options, describes the demand-side management and supply-side resource options available to BC Hydro. Feasible options have been described in a comprehensive database, and were modelled as part of the portfolio evaluation process in Part 6. Options that were considered feasible were resources:

- Available in B.C.;
- Available to BC Hydro from other jurisdictions as imports;
- With developed or advanced developing technologies;
- With sufficient information to characterize the resources for trade-off analyses; and
- With information sources that enable transparent and reviewable data inclusion.

There was sufficient information to characterize over 150 feasible technologies, projects, project bundles and programs for evaluation and inclusion in the database. Among these projects were approximately 800 small and micro hydro projects, bundled into price-range groups for entry in the database. The projects listed in the database were based on the best available information in public domain at the time. They are not considered a comprehensive list of all possible current or future project activity. Resource options were identified in the following categories:

- Demand-side management
    - Power Smart programs
- Alternative and Clean Energy
    - Small and micro hydro (run-of-river, up to 50 MW)
    - Biomass (woodwaste, municipal solid waste, biogas)
    - Geothermal
    - Wind
    - Wave
    - Tidal current
    - Solar (building-integrated photovoltaic)
    - Fuel cells
- Thermal generation
    - Natural gas
    - Coal
    - Oil

    - Diesel
- Large hydro (greater than 50 MW)
    - New large hydro
    - Pumped storage
- Resource Smart (BC Hydro's program to generate additional energy from existing resources)
    - Hydroelectric facilities
    - Burrard Thermal Generating Station
- Downstream Benefits
- Transmission (capacity transfer capability)

Nuclear energy was not included, as directed by the 2002 B.C. Energy Plan.

Resources were described and information was compiled based on a list of descriptors, or attributes (e.g., dependable capacity, cost of energy), that were linked to the overall planning objectives for the IEP. These planning objectives included economic, reliability, environmental, private sector involvement and risk management objectives. Attributes were organized in a similar way. Appendix A provides a complete list of attributes. The attributes were organized under the following topics:

- Financial;
- Technical;
- Environmental and social;
- Private sector involvement; and
- Development and Price uncertainty.

Available data and descriptions were then gathered for each resource option and compiled in the database. No additional resource studies were conducted as part of the 2004 IEP, although some financial reanalysis was conducted for alternative energy resources to reflect financial aspects of private sector development and financing.

The project list and information in the database is not exhaustive, as most of the information was based on past studies by BC Hydro and consultants. Private sector project information gathered through calls for tenders is confidential, unless made publicly available by or at the request of the private developer. However, BC Hydro believes that cost and availability data in each resource category provides a sufficient level of information on a resource-level basis for planning studies.

The results of the resource characterization show that a wide variety of alternatives available to BC Hydro, but at varying costs, different levels of dependability and reliability, and with diverse environmental and social attributes, risks and uncertainties. Figure E.1 depicts the resource categories and the annual average energy estimated for illustrative purposes. Figure E.2 compares unit energy costs for selected resource options.

Figure E.1. Average Annual Energy (GWh) Identified by Resource Type

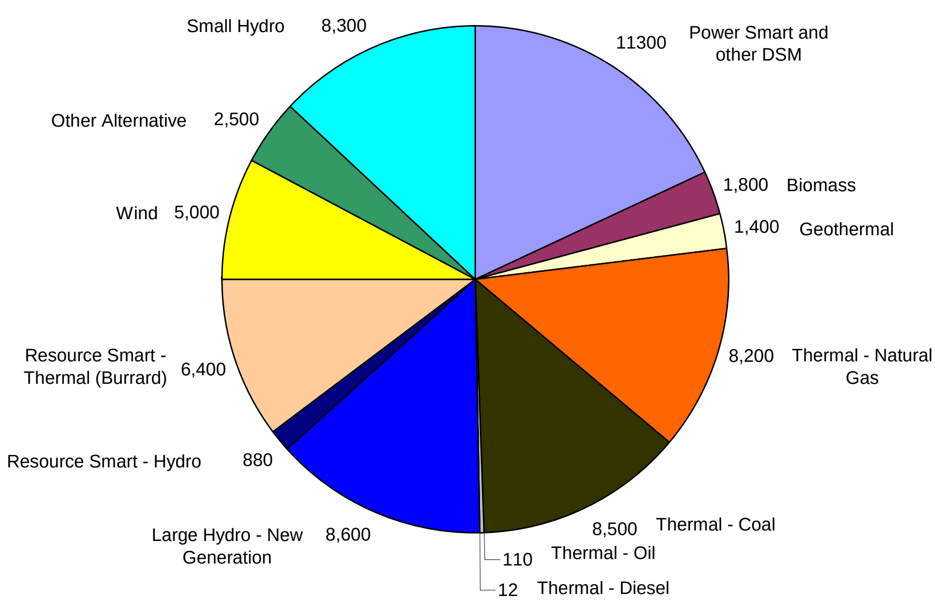
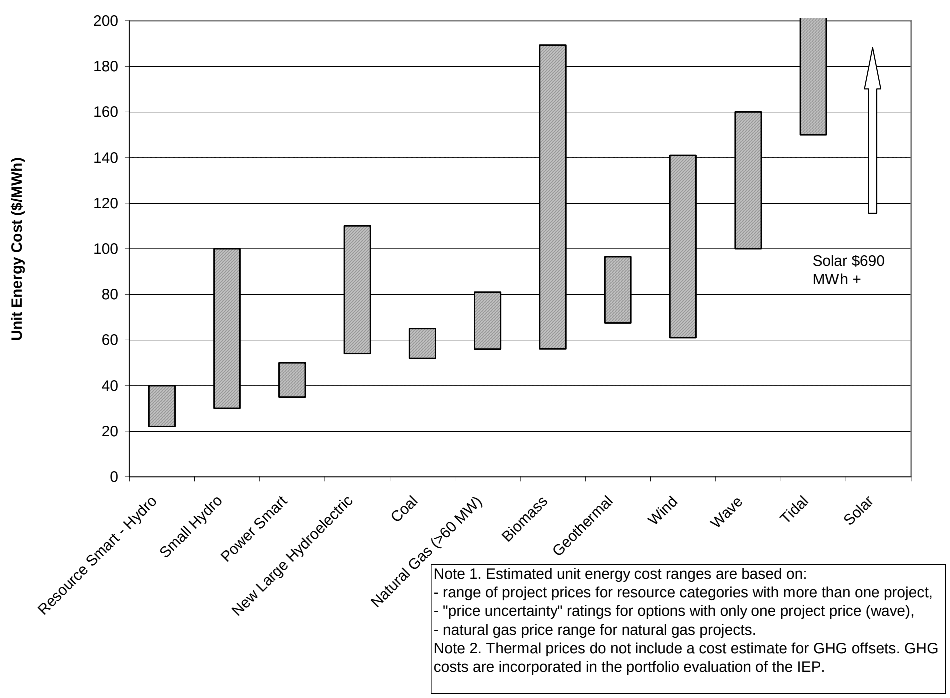
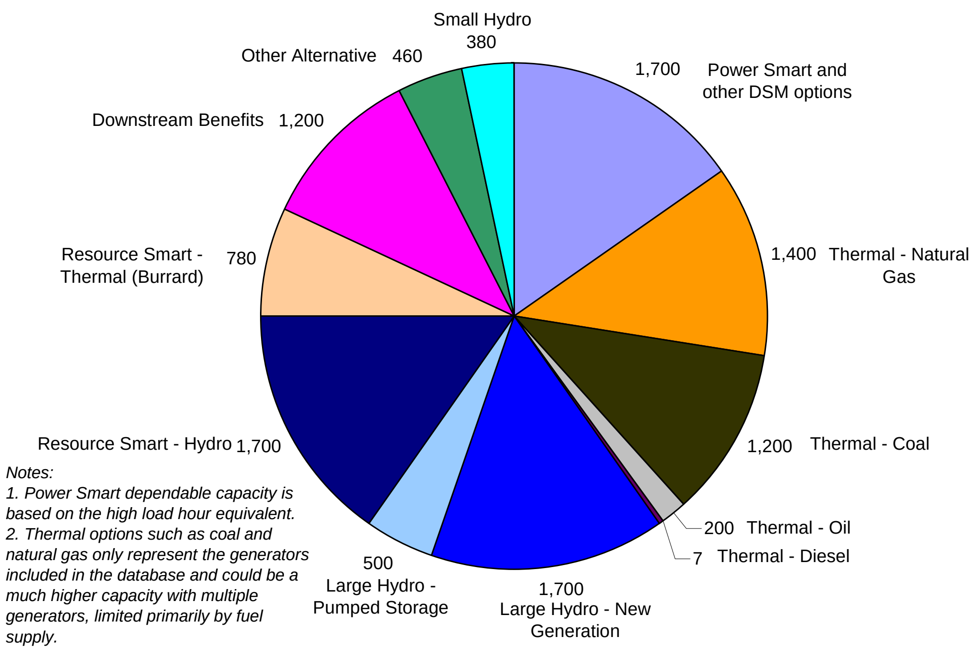


Figure E.2. Illustrative Levelized Unit Energy Cost Chart ($/MWh)



A distinguishing characteristic among the resources described was their ability to provide dependable capacity when electricity is specifically needed. Figure E.3 summarizes the resources that provide dependable capacity, and the cost of their total installed and dependable capacity.

Figure E.3. Dependable Capacity (MW) Identified by Resource Type



In the IEP portfolio analysis, options were combined to create electricity portfolios. A modelling process was used to evaluate the merits of each portfolio. The modelling methods are described in Parts 5 and 6. A strategic plan for energy acquisition and capacity development is provided in Part 7 of the IEP.

1 Planning for the Future – An Overview

An integrated electricity plan (IEP) presents an electric utility's long-term plan for acquiring the electricity resources needed to meet anticipated customer needs. IEPs have been an integral part of BC Hydro's overall business planning process for many years. These plans provide the framework to support prudent investments in demand-side management (DSM), generation facilities and transmission infrastructure. This, in turn, helps to ensure that BC Hydro meets its obligation to supply reliable electricity service to its customers at the least cost, consistent with other planning objectives.

Integrated electricity systems are complex and capital-intensive. In addition, most new resources require significant lead times to build. As a result, electric utilities plan ahead to be sure that the required resources will be in place when needed. IEPs are typically based on load forecasts and resource options that cover 15 to 20 years. Taking this long-term view does not mean that BC Hydro is locked into each of the resource options identified over the planning horizon. In fact, the IEP must be sufficiently flexible to respond to changing market conditions and future uncertainties. In other words, it must meet planning objectives against a range of possible futures.

BC Hydro periodically reviews and updates its IEP. BC Hydro's most recent published IEP was issued in 2000 as an update to the 1995 IEP. A new IEP was to have been completed in 2001. However, the 2001 IEP planning process was put on hold in August 2001, pending the B.C. government's review of provincial energy policy. The B.C. Energy Plan, released in November 2002, enabled BC Hydro to proceed with the development of the 2004 IEP.

The primary purpose of BC Hydro's 2004 IEP is to project the nature and quantity of BC Hydro's resource needs over the next 20 years. This strategic direction guides the management of BC Hydro's owned and contracted energy resources, as well as future acquisition processes.

Specifically, the 2004 IEP:

- Provides the planning foundation for future demand-side management programs (Power Smart), private sector calls for electricity, and other resource acquisitions;
- Demonstrates to First Nations, stakeholders and the British Columbia Utilities Commission (BCUC) that BC Hydro has a plan to meet future customer demand for electricity that recognizes key risks and uncertainties;
- Considers and incorporates, where feasible, feedback from the First Nation and stakeholder engagement process;
- Demonstrates how environmental, social and economic considerations are included in electricity planning; and
- Identifies an Action Plan that specifies initiatives to implement the IEP.

BC Hydro's 2004 IEP has nine components:

- Summary
- Part 1. Introduction and Planning Objectives
- Part 2. Demand-Supply Outlook
- Part 3. Resource Options
- Part 4. First Nations and Stakeholder Engagement
- Part 5. Portfolio Evaluation Process
- Part 6. Portfolio Evaluation Results
- Part 7. Action Plan
- Glossary

2 Introduction to Electricity Resource Options

As the need for electricity in B.C. grows, BC Hydro must identify new resources for managing and serving electricity requirements. Future resource options included were those feasible projects and programs that are in addition to *existing* and *committed* resources. Part 2 of the 2004 IEP describes the demand-supply outlook on the BC Hydro system, where supply is made up of *existing* and *committed* resources. For instance, projects that have been selected in the calls for tenders for customer-based generation and Green[1] Energy generation from 2001 to 2002 were not included as resource options in the 2004 IEP since their contracts are committed and part of future supply.

The two main categories of resource options available to a utility to balance customer demand and electricity supply are:

- Demand-side management (electricity use reduction); and
- Supply (new electricity generation).

Demand-side management includes reducing demand through Power Smart energy efficiency programs, and shifting demand through rate design. Section 4 describes Power Smart options and includes such things as encouraging the use of low-wattage compact florescent light bulbs and the disposal of old, high-energy-use refrigerators.

New electricity supply resources can range from traditional generation technologies to new technologies. Electricity is generated when potential energy in a resource (e.g., water, wind or fossil fuels) is converted into electricity by a generator. For instance, hydroelectric power stations convert the potential energy in falling water into electricity using turbines. Wind energy can also be harnessed to create electricity in a turbine. Fossil fuels and other fuels can be burned to produce heat and steam, which is used to create electricity in a combustion or steam turbine.

The information available on new electricity resource options included in the IEP Resource Option database varies in scope and detail. Specific electricity generation projects had the most detailed level of definition or design (e.g., Site C hydroelectric project, Rumble Ridge wind project, Vancouver Island Generation Project). Some projects had a low to moderate level of information available; either preliminary studies (pre-feasibility studies) or feasibility engineering studies were available. Some projects were described using industry standard information (e.g., oil fuel burned in a simple cycle turbine), or described by conceptual project studies only. The most uncertain information was that garnered from technology descriptions and industry estimates for emerging technologies, such as fuel cells.

Transmission resources were also included in the database because transmission lines transfer electricity from the source to the user, and can sometimes increase the energy available to supply constrained regions.

[1] The term “Green” refers to energy resources that meet BC Hydro’s definition of energy that is renewable, environmentally and socially responsible and licensable.

3 Describing B.C.'s Electricity Resources

Identifying and describing resource options plays a key part in the modelling of electricity portfolios. The description, or *characterization*, of resource options was completed by:

1. Creating a resource inventory: Feasible options for future projects, programs and technologies were identified and inventoried by resource type.
2. Developing a resource characterization framework: A list of descriptors (characteristics) for technical, financial and other information was developed to describe each option and feed into the portfolio modelling.
3. Developing a resource option database: Available data for resources and projects was compiled into a database, including financial information, energy and capacity estimates and geographic region.

Resource option information has been prepared solely for BC Hydro's electricity planning purposes. This information should not be relied upon by others for design, financing or development decision-making. Actual technical and financial project information will require further study and verification and may vary from the information used in this Part.

3.1. Resource Inventory and Categories

Over 150 resources, projects and programs were identified for inclusion in the IEP. These projects are detailed in information sheets from the database included in Appendices B through G.

The projects listed in the database were based on the best publicly available information at the time the characterizations were completed (November 2003), and was not considered a comprehensive list of all possibilities, nor an indication of future project activity. The list is considered preliminary and not exhaustive, and may be updated periodically with additional information. The option inventory was drawn from:

- BC Hydro studies and reports;
- Engineering consultant review and input;
- Publicly available information about independent power producer (IPP) applications for various resource monitoring initiatives;
- Past integrated electricity plans (1995 and 2000 Update);
- Discussion with stakeholders and BC Hydro staff members;
- Industry research and literature review; and
- Public domain proponent and project lists from the public calls for generation including the 1994 call for tenders, and the customer-based generation and Green Energy generation calls from 2001 to 2003.

A wide range of resource options was compiled into the following primary and secondary categories:

- Demand-side management
  - Power Smart programs
- Alternative and Clean Energy
  - Small and micro hydro (run-of-river, up to 50 MW)
  - Biomass (woodwaste, municipal solid waste, biogas)
  - Geothermal
  - Wind
  - Wave
  - Tidal current
  - Solar (building-integrated photovoltaic)
  - Fuel cells
- Thermal generation
  - Natural gas
  - Coal
  - Oil
  - Diesel
- Large hydro (greater than 50 MW)
  - New large hydro
  - Pumped storage
- Resource Smart (BC Hydro's program to generate additional energy from existing resources)
  - Hydroelectric facilities
  - Burrard Thermal Generating Station
- Downstream Benefits
- Transmission (capacity transfer capability)

In addition to the Clean energy technologies listed above, BC Clean electricity[2] includes:

- Cogeneration
- Resource Smart upgrades;
- Most projects acquired under BC Hydro's Customer-Based Generation call; and
- Low-impact medium and large hydro.

[2] As outlined in the B.C. Energy Plan, BC Clean electricity refers to alternative energy technologies that result in a net environmental improvement relative to existing energy production. The scope of the "BC Clean" definition is subject to refinement and final approval by the Minister of Energy and Mines.

Nuclear energy was not included or characterized as part of the 2004 IEP because the Energy Plan excludes this resource from consideration.

3.1.1. Distributed Generation

Distributed generation is power generation, usually smaller-scale, characterized primarily by the fact that it is located near the load it will satisfy. It may or may not be grid-connected. Distributed generation can include small and micro hydro, solar photovoltaic, fuel cell, wind turbine, microturbine and various internal combustion engine systems. Thus, distributed generation, or distributed resources, was not a category unto itself, but was included within the appropriate resource and technology categories.

Microturbines were not specifically included as a resource option, but are recognized as a potential distributed generation resource. Microturbines have small capacities, ranging from 25 to 300 kW. They can be powered by a variety of fuels, including natural gas, and are used for applications like greenhouses, hydroponics, apartment complexes, etc. Microturbines have essentially been covered by the inclusion of internal combustion engines, although microturbines differ in that they are rotational and not reciprocating.

3.1.2. Emerging Technologies

The resource option inventory includes the options that available data show to be realistic and feasible. Leading edge and emerging technologies were generally not included as future resource options in the IEP, primarily due to a lack of usable data. Some emerging technologies (e.g., ocean wave, tidal current) were included, although data based on project experience was limited or not available.

Coal gasification is still in the development stages, and has been built at a few facilities. As a result, it was not included in the database, but may be an option in the future. Development cost is currently higher than conventional coal generation, and GHG emissions higher than natural gas combined cycle turbine technology, both of which are included in the resource options.

Large-scale solar thermal energy production was not included in the database as it was not viable due to cost, particularly under B.C.'s lower solar resource. However, technology advances will likely be monitored and may be incorporated into future IEPs as practicable.

BC Hydro participated in the Rocky Mountain Institute's workshop, "Exploring Vancouver Island's Energy Future" (see Part 4, Appendix C). The workshop highlighted emerging technologies, rate options, and other alternative resource options. Some options presented in the report are presented in the 2004 IEP (e.g., ocean wave generation). Other resources are currently under study as part of follow-up activities by BC Hydro and other parties (e.g. time-of-use rates, energy storage and cogeneration potential).

Emerging energy storage technologies, such as superconducting magnetic energy storage systems (SMESs), may be options for the future. SMESs store energy in the field of a large magnetic coil with direct current flowing. Low-temperature SMES cooled by liquid helium are commercially available. High-temperature SMES cooled by liquid nitrogen are still in the development stage and may become a viable commercial energy storage source in the future.

Over the next 20 years, new fuels and technologies will emerge, and will be incorporated in future updates of the database and integrated electricity plans where practicable.

3.2. BC Hydro's Resource Option Database

BC Hydro developed a resource option database to store the resource information in a standard format, and to facilitate the input of resource data to the modelling and analysis tools. The database links the resource option information with the portfolio evaluation model, MAPA (Multi-Attribute Portfolio Analysis).

The resource option database structure was based on the resource characterization framework, with the database fields made up of resource characteristics (e.g., resource type, total capital cost, installed capacity). The level of detail provided for each resource depends on the level of study and information available for the characteristic as of November 2003.

3.3. Resource Characteristics

BC Hydro developed a list of resource information (characteristics) required to run the portfolio evaluation models and a comprehensive resource characterization framework. Figure 3.1 shows how the resource attributes align with the planning objectives and portfolio evaluation considerations.

Figure 3.1. Resource Option Attribute Selection Example

Planning Objective:

Minimize Long-term Ratepayer Costs.

↓

Portfolio Evaluation Measure:

Net Present Value or Rate Payer Impact

↓

Resource Option Attributes:

Capital Cost, Operating Costs, Financial Assumptions, Project and Developer Tax Treatment.

The database included specific information and assumptions under the following categories:

- Project (general);
- Financial;
- Technical (including reliability);
- Environmental and social;
- Private sector involvement; and
- Project development and price uncertainty.

BC Hydro did not conduct any additional resource studies or engineering estimates as part of the 2004 IEP. However, financial assumptions and unit energy cost estimates for alternative energy resources were re-evaluated (see Section 3.3.2 below). Where attribute information was not available from BC Hydro or consultant studies, estimates were made and explained in the database, or the field was left blank and "unknown" printed in the information sheets. BC Hydro experts or external consultants reviewed the content for each project included in the resource option database.

BC Hydro expects to update the resource option database periodically with input from studies, stakeholders and independent power producers (IPPs).

3.3.1. Project Information

The resource option database describes each project with the following data:

- Project name;
- Resource type;
- Study level;
- Geographic region; and
- Project description.

Geographic regions were based on the BC Hydro transmission regions because the ability of supply to meet load depends on the transfer capacity of the transmission lines from one region to another. The location of demand and the ability of the transmission system to serve that demand is an important factor in IEP studies. The 2004 IEP used eight geographic/transmission regions:

- Central Interior;
- East Kootenays;
- Kelly/Nicola;
- Lower Mainland;
- North Coast;
- Peace River;
- Selkirk Area; and
- Vancouver Island.

Appendix A includes a figure displaying these geographic regions (Figure A.1).

3.3.2. Financial Assumptions

The aim of the resource option characterization was to assess potential projects and energy prices from an independent power producer's (IPP) point of view since the B.C. Energy Plan encourages BC Hydro to obtain future supplies of energy from the private sector. To this end, BC Hydro re-estimated unit energy costs with a new spreadsheet-based model that incorporated private sector financial assumptions.

Several resource types would likely be implemented only through BC Hydro-based programs and would involve financial assumptions unique to BC Hydro, BC Transmission Corporation and other Crown corporations. These resource types include:

- Demand-side management programs (Power Smart and rates);
- Resource Smart (BC Hydro facility upgrades);
- Transmission; and
- Large hydro projects.

The financial assumptions unique to each resource type are described in Appendix A.

3.3.3. Technical Information

Technical information describing each resource included:

- Installed capacity (nameplate or gross capacity);
- Dependable capacity;
- Annual average energy; and
- Firm energy.

Each project has a nameplate, or gross, capacity as specified by turbine manufacturers or resource potential. This nameplate capacity is the maximum output a turbine could achieve, although for some turbines this output may never be achieved due to losses in a system. The nameplate capacity can be used to broadly estimate energy production using standard capacity factors.

BC Hydro defines dependable capacity as the maximum capacity that a plant or unit can reliably provide. Different utilities, regions and scenarios require specific definitions for dependable capacity. For the purposes of the 2004 IEP, dependable capacity from various resource options was estimated as the capacity that can reliably be provided for three hours in the peak load period of weekdays during two continuous weeks of cold weather.

For major hydroelectric generating plants and plants with significant controllable upstream storage BC Hydro calculates dependable capacity based on an 85 per cent confidence level of assumed 50-year streamflows.

For IPP plants, the availability of fuel (e.g., natural gas, water, biomass) during the cold winter period is a key factor for estimating dependable capacity. Actual billing information, from IPP to BC Hydro, is often used to revise the estimated dependable capacity.

Appendices C and D provide additional discussion of dependable energy estimates for alternative resources.

Annual average energy is that energy expected to be produced over the period of a year. For example, using hydrologic records, average inflows at a small hydro plant could be used, with other key plant assumptions, to estimate average annual energy.

Firm energy is the energy that is available (i.e., equalled or exceeded) at any time, either for a given period such as a year, or for an analysis period such as a period covered by flow records. For most resource options, the firm energy is estimated to be the amount of energy production that could be relied upon during a given year.

3.3.4. Environmental and Social Aspects

Resource options may have positive or negative environmental impacts or social consequences. Where information was available, environmental and social aspects of resources were included in the resource option database. Available information was also included in the following areas:

- Clean Energy (as defined in the B.C. Energy Plan, yes or no);
- Local and greenhouse gas (GHG) emissions (tonnes/GWh);
- Footprint (hectares); and
- Employment (person-years during construction, and full-time equivalents for full-time jobs).

The IEP process neither assumes approval nor assesses actual impacts of specific projects, but rather assumes that the proponent would follow regulatory and public involvement processes based on relevant regulations and guidelines.

3.3.5. Private Sector Involvement

BC Hydro developed illustrative ratings for expected percentages of private sector involvement in various resource option programs and projects. These ranges are indicators only and are set out in Table 3.1.

Table 3.1 Private Sector Involvement Ratings

Per cent Involvement	Description of Involvement
0 to 5%	Almost no private sector involvement. This would include very small programs conducted by BC Hydro, or very specialized applications.
5% to 25%	Tertiary involvement: limited private sector products/equipment and services. Percentage based on total program or project dollars distributed to the private sector.
25% to 50%	Secondary Involvement: moderate private sector provision of products and services. Percentage based on total program or project dollars distributed to the private sector.
50% to 99%	Primary Involvement: Significant private sector design, build, operate, or provision of other products and services.
100%	Private sector design, build, operate, and ownership.

3.3.6. Project and Price Uncertainties

Forecasting the availability and cost of resources up to 20 years into the future involves uncertainty inherent in any business or technological forecast prediction. In addition, the resource options were described using the best available information, which for some options was at a high, conceptual level. This uncertainty leads to business risks; for example, a new resource planned for acquisition might not materialize in the time required, or resources might prove more expensive than anticipated.

Uncertainty inherent in the preliminary nature of the technical and financial assumptions used to estimate unit energy costs leads to project cost uncertainty. For instance, depending on the level of study conducted and the assumptions made, transmission costs (new lines or substation) or natural gas pipeline costs were either not included, or were estimated in a broad fashion for resources such as small hydro and wind. This difference in the level of study creates uncertainty in estimating project and resource costs, and BC Hydro plans to improve the database periodically as additional studies and details become available.

Uncertainties were described for project development and price. BC Hydro used likelihood ratings of low, medium and high to estimate the uncertainty of these two sets of assumptions for each resource option. Predefined rating categories and professional judgement were used to estimate the likelihood ratings for each project, technology or general resource in the resource option database. Appendix A provides details on project and price uncertainty.

Other uncertainties relate to energy prices, which have not been included in this evaluation of price uncertainty. For instance, there is uncertainty about fuel prices, as discussed in Part 6, Portfolio Evaluation Results.

4 Demand-Side Management

Customers can be encouraged to use electricity more efficiently or curtail use at specific times through various demand-side management (DSM) programs. Such programs generally fall into three main categories:

- **Load reduction** is the reduction in demand as a result of customers improving efficiency of equipment (e.g., lighting and motors, buildings and industrial processes).
- **Load displacement** means that BC Hydro sells less electricity to a customer, usually due to customer self-generation, although the customer's pattern of peak and off-peak periods (load shape) may not have changed.
- **Load shifting** means that the total amount of electricity sold to a customer may not change, but the loads during various time periods change, thus changing the customer's load shape from a utility on-peak period to a utility off-peak period.

BC Hydro's energy efficiency program, Power Smart, includes load reduction and some customer load displacement. Load shifting can be accomplished in some instances through rate design. Rates need to be examined from a broader context than that provided within the IEP; a context that will be developed based in part on the results of the IEP, and includes customer costs of electricity, and marginal costs of supply. BC Hydro plans to evaluate rate design options through studies in 2004, following the IEP.

4.1. Power Smart

The database includes Power Smart programs as options, although they are not typically new energy sources but rather demand reduction measures. Power Smart options were modelled by subtracting a specified amount of energy or capacity requirement from the load forecast, which was then used in the new supply modelling and portfolio evaluation.

Power Smart is BC Hydro's DSM and includes technology changes and load displacement opportunities. BC Hydro launched Power Smart in 1989, primarily as an education, awareness and reward program to encourage energy savings. Within Power Smart, many different program approaches are used, including:

- General information programs to inform customers about generic energy efficiency options;
- Site-specific information programs that provide information about specific DSM measures appropriate for a particular enterprise or home;
- Financing programs to assist customers in paying for DSM measures, including loan, rebate and shared-savings programs;
- Direct installation programs that provide complete services to design, finance and install a package of efficiency measures; and
- Market transformation programs that attempt to change the market for a particular technology or service so that the efficient technology is in widespread use without continued utility intervention.

Appendix B summarizes the following current and future Power Smart programs:

- Power Smart 2 – from F2003[3] to F2012;
- Power Smart 3 – from F2012 to 2017;
- Power Smart 4 – from F2010 to 2024; and
- Power Smart 5 – from F2008 to 2024.

The Power Smart 10-Year Plan can be found at www.bchydro.com/info/epi/epi9213.html.

Power Smart energy savings accumulate over time and are generally assumed to persist once total program goals are achieved, as shown in Figure 4.1. If a particular program were discontinued midstream, the energy savings would not necessarily persist. The energy savings estimates are closely linked to the:

- Start year of the program;
- Demand forecast;
- Plan for continued investment over the period of the program; and
- Ongoing investment in subsequent Power Smart programs.

Figure 4.2 displays the expected total energy savings and the related total resource cost of Power Smart programs.

BC Hydro estimated an equivalent dependable capacity for winter heavy-load hours, based on the energy savings expected during this period. The Conservation Potential Review (Appendix H) describes the approach in more detail. Figure 4.3 depicts the heavy load hour (HLH) winter dependable capacity equivalent for Power Smart.

[3] Dates marked with an F refer to the fiscal year ending March 31 in the year given.

Figure 4.1. Power Smart 2, 3, 4 and 5 Projected Annual Energy Savings

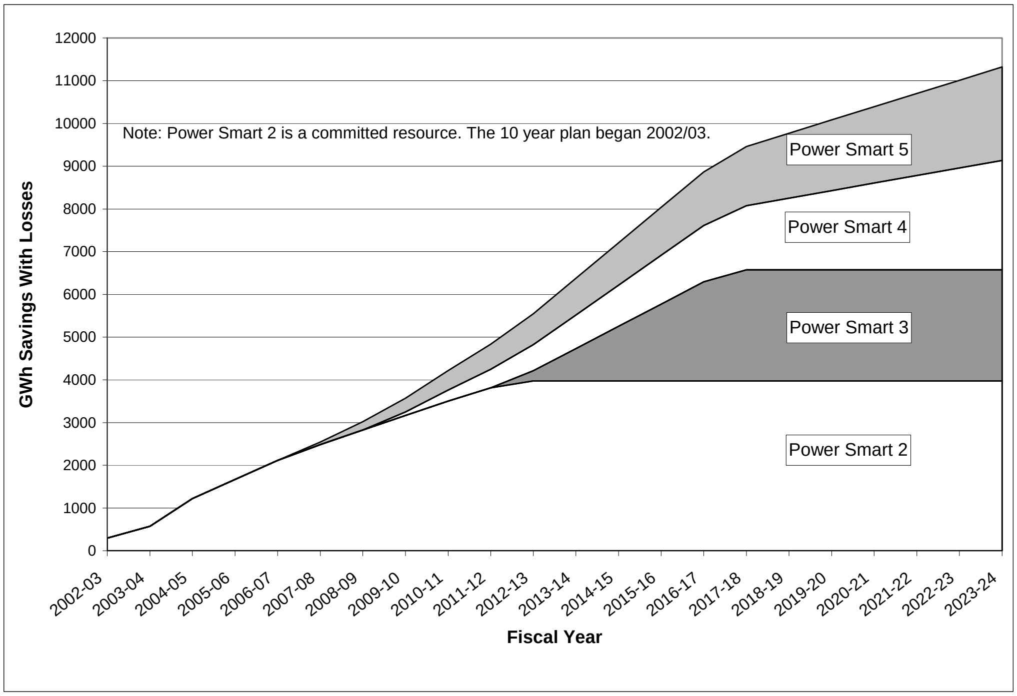
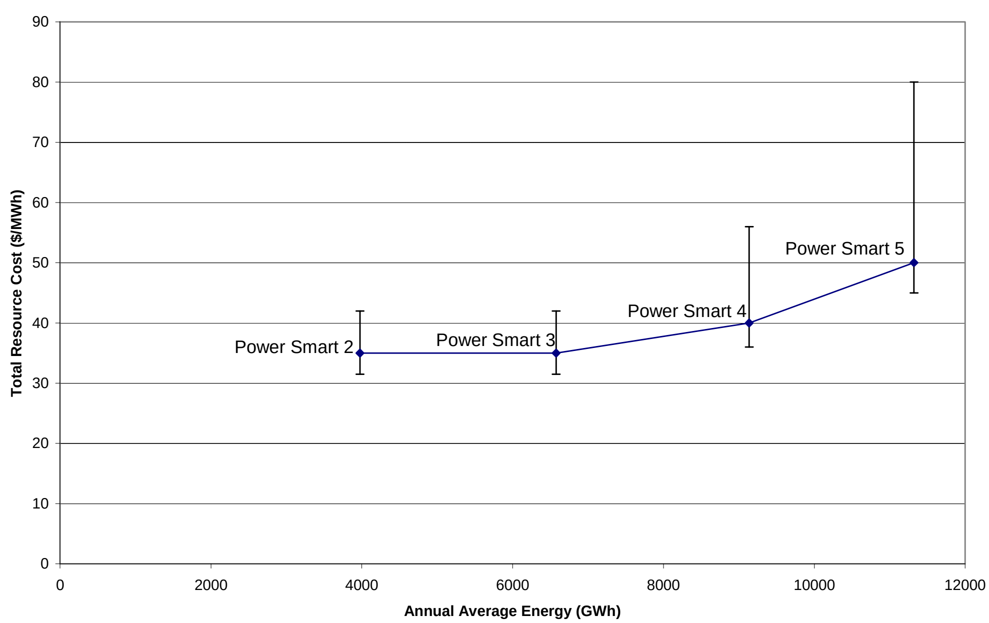
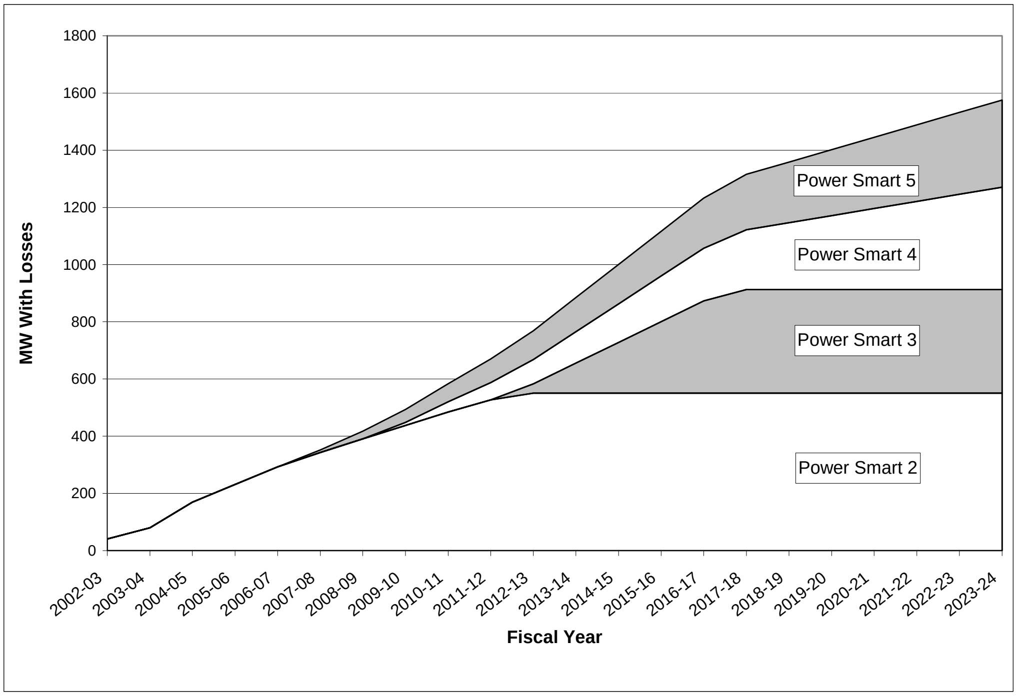


Figure 4.2. Energy Supply Curve – Future Power Smart



Note: Cost range bands are displayed in the supply curves based on the price uncertainty ratings, and reflect uncertainty in the technical assumptions used to make cost estimates. Additional description of these price uncertainty ratings can be found in Appendix A.

Figure 4.3 Heavy Load Hours Dependable Capacity Equivalent – Power Smart



4.2. Demand-Side Management – Capacity Programs

Currently, Power Smart focuses on energy savings, although the Power Smart programs assume some capacity savings. Had the objective of Power Smart been to reduce capacity, BC Hydro would likely have implemented the program differently. BC Hydro has not yet designed specific capacity demand reduction programs, but because demand-side capacity programs have been successful in other jurisdictions, BC Hydro is evaluating whether they could be cost-effective and complementary solutions to system capacity upgrades in B.C.

Demand-side capacity programs generally need more time to implement than moderate system reinforcements such as substation transformer upgrades. However, a Power Smart capacity program may have a shorter timeline and receive stronger public support than a major upgrade, such as a transmission line reinforcement with significant regulatory, environmental and social concerns.

To determine whether capacity programs can defer system reinforcements and be included in future IEPs, BC Hydro needs information to:

- Examine where early system reinforcements will be required;
- Gain a better understanding of the cost per kilowatt of the system reinforcement; and
- Determine the daily load profile of the load that is driving the need for the system reinforcement.

The *Conservation Potential Review 2002* included preliminary findings that DSM measures to reduce the peak demand for electricity on the BC Hydro system, or in a particular region of the system, could reduce peak demand by 550 MW and would involve the following:

- Peak shaving;
- Short-term load shifting;
- Long-term load shifting;
- Load reduction – market and operation optimization; and
- Load displacement – fuel switching – self-generation.

The CPR study was preliminary in nature and intended only to determine whether it would be worthwhile for BC Hydro to spend more effort investigating the subject. If targeted reduction in industrial production were considered, the reduction could be increased to over 750 MW. However, the cost of this capacity is unknown and may be high, based on the value of electricity and associated production to industrial customers. Given the potential magnitude for the industrial sector, BC Hydro is considering further investigation into capacity programs, and their future inclusion in resource planning processes.

5 Supply-Side Options

5.1. Alternative and Clean

This section describes resource options and technologies that are alternatives to traditional electricity generation. Many of these projects and resources are *Green*, defined in BC Hydro's Green Energy definition as energy that is renewable, environmentally and socially responsible and licensable. The B.C. Energy Plan describes a category of resources referred to as "Clean Energy." Alternative or emerging supply-side resources are described in this section, therefore cogeneration, Resource Smart and low-impact hydro generation although they could be classified as Clean in many instances, have not been included in this section.

Section 3 of Appendix A includes the definitions for the Clean and Green attributes.

5.1.1. Small and Micro Hydro

The geography of British Columbia, with its numerous steep mountain creeks and rivers, provides many opportunities for small and micro hydroelectric generating facilities. Micro hydro refers to hydroelectric power plants with a capacity of less than 2 MW, and small hydro refers to hydroelectric power plants whose capacity is greater than 2 MW and less than 50 MW. In order for small and micro hydro plants to be classified as Green under BC Hydro's definition, the projects must be run-of-river, which means that the streamflow passing through the powerhouse is basically the same as the natural streamflow. This implies that there is no (or minimal) storage reservoir.

The technology for small and micro hydro is well established, and there are a number of small or micro hydro power plants in B.C. operated by BC Hydro, and many by IPPs. In general, a small or micro hydroelectric generating facility consists of an intake structure, water conduit, powerhouse, tailrace, substation and power lines. The intake structure may consist of a small dam to create a headpond. A water level monitor located at the intake is wired into the plant controller at the powerhouse. Changes in water level signal the turbine gates to open or close to maintain a constant water level, with the power output changing accordingly.

Pingston Creek Small Hydro Project, owned by IPPs Canadian Hydro Developers, Inc. and Brascan Power

Most small or micro hydro projects use a penstock to convey the water from the intake to the powerhouse. At the powerhouse, a turbine converts the water pressure to mechanical energy in the form of a rotating shaft, which in turn drives the generator and produces electricity. The water is then returned to the stream channel by the tailrace. The tailrace is usually a short open channel, but could also be a pipe or tunnel.

Different regions of B.C. have very different hydrologic characteristics. Interior creeks, for example, tend to have low flows in the winter when most of the precipitation is falling as snow, while coastal creeks display a "flashy" response to heavy rainstorms during the winter. Without a storage reservoir, small and micro hydro power plants can generate electricity only when they receive the water, and the power output follows the level of water. As a result, there are times when the turbines are not running at full capacity due to low flows, and other times when the turbines cannot use all the water that is available. In addition, there is considerable yearly variation in streamflow, which means a yearly variation in the amount of energy generated.

Aside from minimizing impacts on fish bearing streams, there are no major barriers to small and micro hydro development in B.C., since both the technology and the regulatory process are well established in the province.

Small Hydro Results

The detailed data presented in Appendix C was obtained from the B.C. Green Energy Study (BC Hydro, 2001; BC Hydro, 2002). For this study, Sigma Engineering developed an inventory of small and micro hydro in B.C. from maps and regional hydrology studies. General assumptions were made regarding site configuration, cost and energy production, and are described in Appendix C.

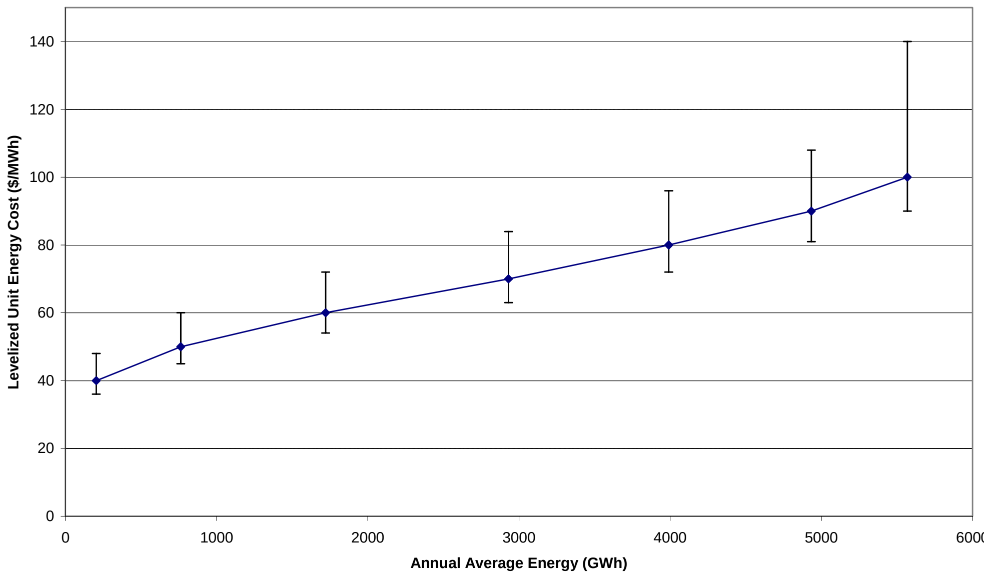
Over 800 small hydro projects have been listed in the resource options database. These projects are in addition to projects bid into BC Hydro's calls for tenders. They were bundled into price categories between \$40/MWh and over \$100/MWh, and are displayed in Figure 5.1.

A number of small hydro projects were identified with capacities greater than 20 MW, although the Sigma study focussed on smaller capacity projects. Figure 5.2 displays the unit energy cost estimates and supply assumptions for these projects.

Small hydro projects that were not located in one of BC Hydro's eight transmission regions were not been included in the resource option database. In general, extending transmission service for a significant distance to small hydro projects is not cost-effective. However, there is the potential to bundle a number of small hydro projects in order to make the transmission extension, and in turn the projects, financially viable. These projects have not been included specifically, but since the IEP is not for project selection but rather a resource planning process, this omission should not have a material effect on results.

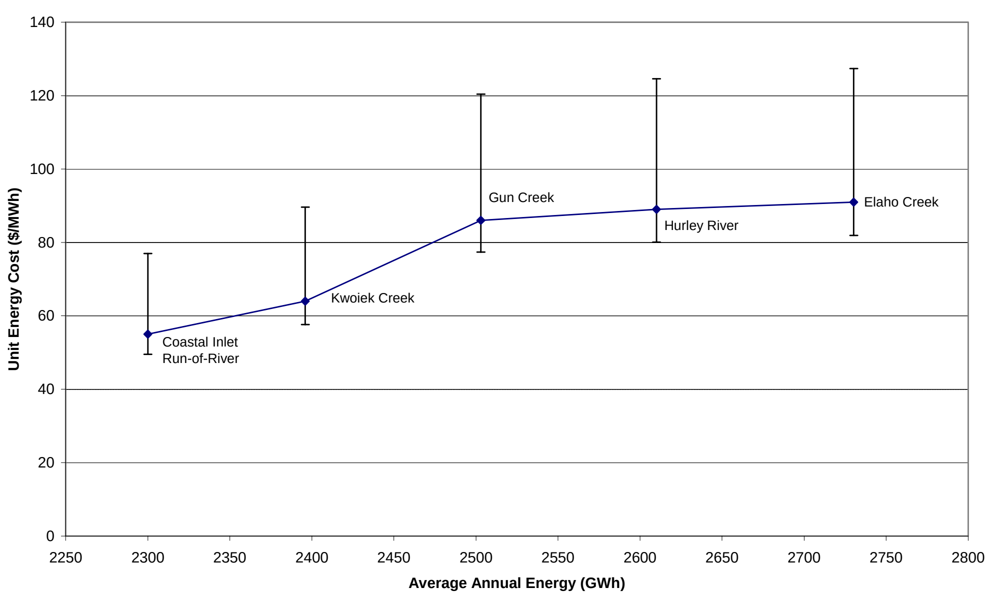
Environmental and social issues related to small and micro hydro development would be addressed as part of regulatory processes during development. Fisheries issues are usually the most important environmental issue and are assessed for individual sites. Small and micro hydro sites are generally located on small, steep creeks where fisheries impacts are low. Land impacts for run-of-river hydro plants are generally minor, since there is no storage reservoir. In some cases, the headpond created for the intake structure does flood some land, but the area is usually small. Impacts on wildlife are generally low for small and micro hydro development, although linear structures such as penstocks or canals, if not buried, may interrupt normal wildlife movement.

Figure 5.1. Small Hydro <20 MW Energy Supply Curve



Note: Cost range bands are displayed in the supply curves based on the price uncertainty ratings, and reflect uncertainty in the technical assumptions used to make cost estimates. Price uncertainty does not include uncertainty in market or fuel prices. Additional description of these price uncertainty ratings can be found in Appendix A.

Figure 5.2. Small Hydro >20 MW Energy Supply Curve



Note: Cost range bands are displayed in the supply curves based on the price uncertainty ratings, and reflect uncertainty in the technical assumptions used to make cost estimates. Price uncertainty does not include uncertainty in market or fuel prices. Additional description of these price uncertainty ratings can be found in Appendix A.

Because many of the small hydro development sites are located away from population centres, the social impacts are low and generally positive due to employment opportunities. Some sites may involve First Nations issues. Noise and traffic may be an issue during construction if the site is located close to an urban centre. Site development may impact recreational uses of the river or creek, such as kayaking or fishing.

5.1.2. Biomass

Biomass is organic material derived from plants. The chemical energy in biomass can be extracted through combustion to generate heat or electricity. The most abundant source of biomass fuel in British Columbia is wood residue, a by-product of sawmills and other forestry operations. Other biomass resources include municipal solid waste, demolition and land clearing waste, and agricultural waste. Anaerobic decomposition of organic material in landfills produces another source of biomass fuel, landfill gas, which can be burned to generate electricity.

Williams Lake Generating Station
Williams Lake, British Columbia

In British Columbia, over 600 MW of power is currently generated from biomass fuels, mainly at pulp and paper mills on Vancouver Island and the Coast. However, other biomass generation facilities have recently been completed, including:

- A turbine generator recently installed at the Burnaby incinerator that generates 22 MW of power from 250,000 tonnes of MSW each year; and
- A 5.6 MW landfill gas system that has recently been installed at the Vancouver landfill.

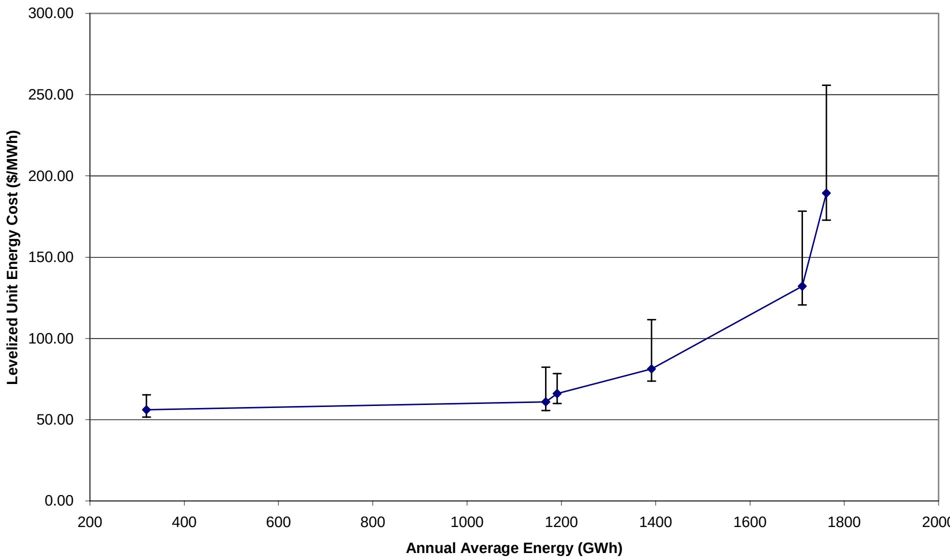
Biomass Results

The detailed data presented in the resource option database for six potential biomass projects represents a resource potential of 219 MW, and 1762 GWh per year at costs in the order of $56 to over $150/MWh (Figure 5.3).

Two of the identified projects were MSW, one project using biogas, and the remaining projects using wood residue. Generally, when a secure fuel supply contract is in place, the installed capacity of biomass projects is considered dependable and the annual energy production is considered firm.

Barriers to biomass generation in B.C. are usually related to fuel supply and project financing. Energy generation is not the primary interest for sawmills where most of the wood residue fuel is available, although Power Smart financial assistance for load displacement can encourage some projects to go ahead.

Figure 5.3. Biomass Energy Projects, Supply Curve



Note: Cost range bands are displayed in the supply curves based on the price uncertainty ratings, and reflect uncertainty in the technical assumptions used to make cost estimates. Price uncertainty does not include uncertainty in market or fuel prices. Additional description of these price uncertainty ratings can be found in Appendix A.

Wood Residue

The largest opportunities for biomass development are primarily for wood residue. Approximately 1.6 million bone-dry tonnes is incinerated in beehive burners, making no productive use of the resource and creating environmental and health problems. There are opportunities to use this residue for energy generation.

Municipal Solid Waste

Less than 10 per cent of the municipal solid waste (MSW) disposed of in landfills in B.C. is incinerated. Landfills continue to be the primary method for disposing of MSW in British Columbia because of their relatively low cost. While there is potential for more incineration and power production from MSW, based on the current cost of electricity it is unlikely that there will be significant additional power generation from MSW in British Columbia in the near future.

Biogas

Much of the landfill gas generation potential has been developed in B.C. For example, the Vancouver Landfill Gas Cogeneration Project, in Delta, B.C., went into operation in September 2003. This 5.6 MW (electric) and 6.7 MW (thermal) cogeneration facility generates electricity, which is sold to BC Hydro under a 20-year Green Energy contract. Thermal energy, in the form of hot water, is sold to the CanAgro Produce Ltd. greenhouses under a 20-year contract. In addition, the Victoria Hartland Road Landfill 3 MW project is under development.

Although small projects at landfill sites located in the Interior (e.g., Cache Creek Landfill) could be developed, collection systems would have to be installed for potential power generation projects to be feasible. Generally, landfill gas does not represent a significant source of power for the province.

Demolition and Land Clearing

An estimated 1.5 million tonnes of demolition and land clearing waste is available annually on the B.C. Mainland. The majority is delivered to landfills at a cost considerably lower than the fee that would be required to cover the cost of transporting, sorting and processing the demolition and land clearing waste so it would be suitable as a fuel. Unless disposal in landfills is restricted, it is unlikely that this biomass source will be a viable fuel in the foreseeable future.

Biomass Impacts

Sustainable biomass resources were considered Green and Clean Energy because they are renewable and do not contribute to global warming. (See Appendix D for additional discussion about emissions from biomass generation.) Because biomass projects are generally situated in developed and populated areas, they do not require long transmission line extensions, although the transmission or distribution may require system upgrades. As well, many biomass projects can contribute to economic development through employment and encouragement of industry.

5.1.3. Geothermal

Geothermal energy refers to the natural heat source in the earth's crust. This energy can be extracted from the earth, usually in the form of hot water or steam that can be used for electricity generation. The IEP does not explore heat extraction for heating and cooling buildings, and geothermal energy has not been developed for electrical generation in B.C. However, it has been developed for this purpose in a number of locations world-wide, including the United States, Southeast Asia and New Zealand. In the western United States, existing geothermal operations typically vary in size from 10 MW to 300 MW.

Geothermal resources are most commonly associated with geologically young areas with recent volcanic activity or with crustal rifts. In B.C., areas such as the Garibaldi Volcanic Belt, the Mt. Edziza Complex, the Clearwater Complex or rifts such as the Lakelse Lake and Okanagan Region all have geothermal potential.

Superheated thermal water is recovered from geothermal reservoirs by drilling production wells connected by steam lines to a central power plant.

Off-the-shelf geothermal power plants are available from a variety of large suppliers and some speciality companies. Common turbine sizes are 2 MW, 10 MW, 20 MW, 55 MW and 100 MW, installed separately, in pairs or in other combinations.

Barriers to geothermal development in B.C. are primarily related to insufficient data about the geothermal resource. Costly exploration and confirmation drilling is necessary at the outset of a project to determine production characteristics and the ultimate commercial production capacity of a resource. Geothermal resources greater than 80^o Celsius are vested in the provincial government under the *Geothermal Resources Act.* Exploratory work is conducted under Crown permits, which may be converted to production leases. These permits may be issued either by competitive public tender or the provincial Cabinet may issue a permit by an Order-in-Council where a proponent has a solid proposal and is well capitalized. For example, the government is now requesting such proposals for unconventional development projects in the petroleum and natural gas sector.

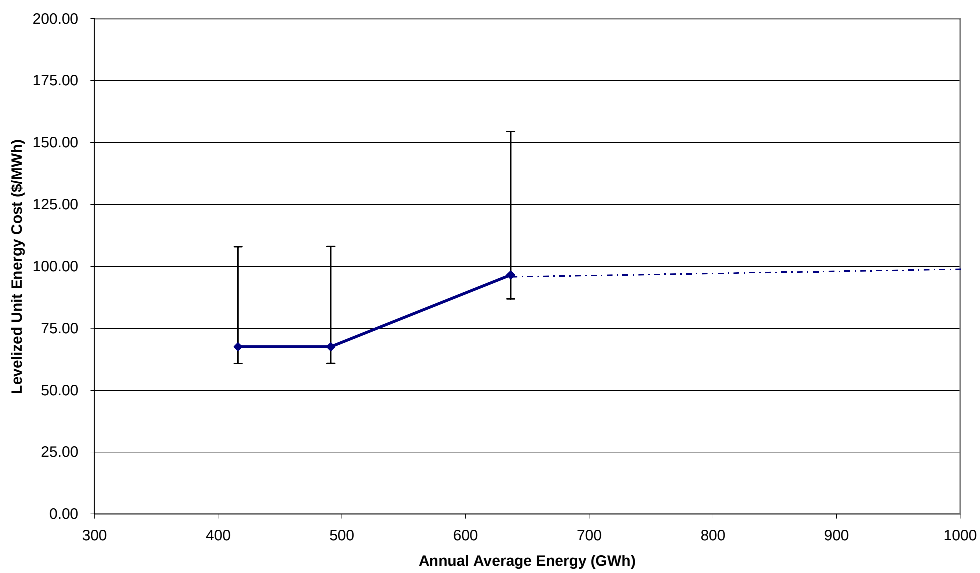
Geothermal Results

BC Hydro identified five sites that offered the greatest potential for commercial development of geothermal energy. Four sites had sufficient information to be included in the database.

Geothermal projects at Lillooet were not included in the database because there has been very little exploration work completed, even though the geothermal sites are close to major load centres. A limit to production for the Lillooet projects may be the low grade heat source. Fairbank Engineering recommended in 2002 Phase I and Phase II exploration be conducted to characterize the geothermal resource and cost estimates.

The geothermal resource potential for the identified sites is between 155 MW and 1,070 MW. The capacity factor of geothermal resources is 100 per cent and the availability of the plants was estimated at 95 per cent. This yields an energy production potential of between 1,300 and 9,000 GWh (Figure 5.4).

Figure 5.4. Geothermal Resources Supply Curve



Note:
1. Cost range bands are displayed in the supply curves based on the price uncertainty ratings, and reflect uncertainty in the technical assumptions used to make cost estimates. Price uncertainty does not include uncertainty in market or fuel prices. Additional description of these price uncertainty ratings can be found in Appendix A..
2. Supply curve has been extended to indicate potential geothermal resources not included in the database.

The levelized cost of geothermal energy is between $67/MWh and $90/MWh, as indicated in Figure 5.4. Since capacity factor and resource availability are both high, geothermal plants are ideally suited to supply base power requirements.

Geothermal power is environmentally benign. A typical flash steam plant emits minor amounts of sulphur and nitrous oxides and 10 tonnes CO_2/GWh). Binary plants, employed at moderate temperature geothermal fields, use both hot water and a secondary (hence, binary) fluid, and are essentially closed-loop and free of emissions. Spent geothermal fluid is commonly re-injected into the geothermal reservoir.

Land requirements for geothermal development, including land required for the power plant and well field, vary with the geothermal reservoir conditions. A well field to support a 100 MW development would require 200 to 2,000 hectares. However, while supporting the power plant, most of the land could still be used for other purposes. For the project footprint information in the resource option database, the area of the geothermal reservoir was used.

Projects must consider the cultural and religious significance of areas having geothermal potential. In addition, competing interests such as tourism facilities or First Nations traditional heritage sites may have concerns about geothermal facilities affecting the flow feeding hot springs.

5.1.4. Wind

Wind energy has not yet been developed on a large scale in British Columbia. Installations have typically been small-scale residential or farm installations in areas that are not connected to the electrical grid. However, wind energy is used widely in Europe and the United States, and the industry has grown considerably in the past 10 years. Wind turbine technology has seen many improvements over the last 20 years, resulting in improved efficiencies and subsequent cost reductions. The wind industry is now well established and the technology has proven reliable in many locations and different environments.

British Columbia is the first landfall in Canada for the prevailing westerlies, a broad west-to-east air current that crosses the North Pacific Ocean in the northern latitudes. The prevailing westerlies, with their embedded high- and low-pressure systems, are responsible for much of the wind energy that crosses the province. At lower elevations, the complex topography of the Coast and Interior mountain ranges channels the wind into set directions. Elevations of land such as hilltops and ridges experience accelerated wind speeds as the air becomes compressed crossing the obstruction. In other situations, winds may be funnelled by valleys and mountain passes. Local winds are also strongly affected by daily heating and cooling of the land, especially during the summer.

The major barrier to wind development in B.C. is the higher cost of wind energy relative to other Clean resources such as small hydro. Federal tax programs and production incentives have assisted growth in the wind industry in Canada to some extent. However, federal production incentives are lower than what is needed to stimulate a robust and large wind industry, and lower than those presently provided in Europe and the U.S.

Wind Results

Sites included in the database are primarily ones that were identified during BC Hydro's wind resource assessment program (2001 to 2004). This program focused on sites close to BC Hydro's integrated transmission and distribution system that could be developed with minimal impacts. These sites had moderate to good potential for wind development. Though by no means exhaustive, the program provides a useful characterization of the resource potential in B.C. for long-term planning purposes.

Wind monitoring has been conducted at most of the sites in the resource option database. The nine land based sites with monitoring could have a total installed capacity of over 600 MW and could produce approximately 1,800 GWh per year (Figure 5.5). Because of the intermittent nature of the wind resource in B.C., dependable capacity for wind sites is zero. Further monitoring or studies may provide information to allocate some dependable capacity to wind projects, but until then, these projects would provide primarily energy, with limited capacity.

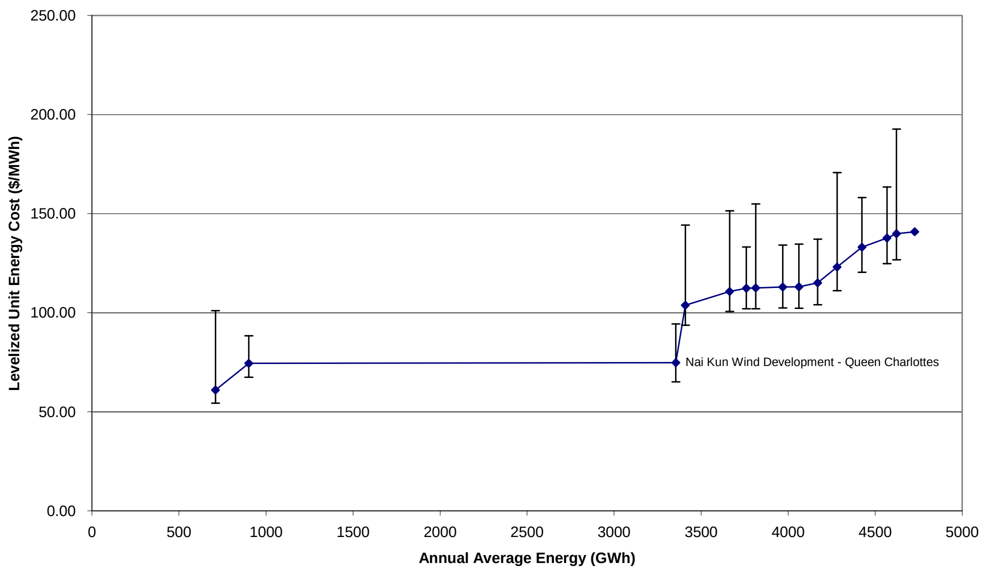
More recent wind speed monitoring conducted by private wind developers has been reported to have identified world class wind energy sites in select but more remote locations on the B.C. coast and in certain Interior regions. Private wind developers report that their best wind projects in B.C. include development sites with tested wind speeds in the highest ranked Wind Power Class 7 classification. The *Wind Energy Resource Atlas of the United States,* (U.S. Department of Energy) characterizes these newly discovered sites as Superb, with annual average wind speeds exceeding 8.8 metres/second at 50 metres elevation. Class 7 sites have been identified in the Peace River region of northeastern BC, and in northern Hecate Straits. Other commercial grade wind sites include those characterized as Class 5 and Class 6 sites, which have been located in the northeast Interior, and on north end of Vancouver Island. Capacity factors[4] on these new private sector B.C. wind energy projects are expected to range from 35 to 45 per cent or higher – values closely meeting or exceeding the best existing wind farms in the world, including new renewable wind developments in California, Washington, Oregon and Alberta. Although many of these sites are in remote locations, some are reported to have the potential to generate wind electricity at an energy price competitive with mid-range gas, coal and other clean technologies, including many small hydro projects.

Included in the database are two projects identified by IPPs: a 700 MW offshore wind development in Hecate Strait (Queen Charlotte Islands) and a 165 MW

[4] Capacity factor is the actual annual energy output divided by the theoretical maximum output, if the machine were running at its rated (maximum) power during all of the 8,766 hours of the year. Most wind farm capacity factors are in the range of 25 to 30 per cent.

wind development in the north-east region of B.C. Numerous other sites are being monitored or considered for development by IPPs in B.C.

Figure 5.5 Wind Energy Projects Identified, Supply Curve



Notes:
1. Based on identified projects. The extent of resource is far greater, but at unknown cost.
2. Cost range bands are displayed in the supply curves based on the price uncertainty ratings, and reflect uncertainty in the technical assumptions used to make cost estimates. Price uncertainty does not include uncertainty in market or fuel prices. Additional description of these price uncertainty ratings can be found in Appendix A.

Offshore wind development potential was assessed for BC Hydro off Vancouver Island (Tech-wise, August 2002). The two best sites identified could each accommodate a 50 MW development, and average energy at each site was estimated at 125 GWh per year.

Small-scale wind turbines that are suitable for residential, farm or small business applications are more popular in jurisdictions that allow small-scale renewable energy systems to interconnect with the utility. BC Hydro has received a net metering tariff from the BCUC for projects up to 50 kW. As part of the Green Energy Study for BC (BC Hydro, 2002), the potential for small-scale wind power production in B.C. was estimated at 25 GWh per year, based on 10 kW installations at 1,900 residential sites.

Wind Integration

Several detailed technical investigations of grid ancillary service impacts of wind energy power plants in the U.S.A. (Parsons et al, 2003). indicate that relatively large-scale wind operation will have an impact on power system operation and cost, but at the penetration rates expected in the foreseeable future, will be lower than initially expected. Reasons cited include the:

- Stochastic nature of grid systems, which routinely contend with uncertainties;
- Ability to forecast wind power output over short time frames;
- Actual wind farm power output characterization; and

- Geographical diversity resulting in aggregate smoothing.
- Technical integration of wind development in BC Hydro's system has not been analyzed at a detailed level, but the wind industry in B.C. has recently initiated some studies in conjuction with BCTC.

Wind Impacts

Wind energy meets BC Hydro Green Energy and B.C. Clean Energy criteria since it is renewable and has minimal environmental impacts. Potential impacts on birds are generally considered the most important. Visual impacts can be a concern, especially if the development is within view of communities. Other concerns can include noise, specific blade revolution visual disturbances ("disco effect"), and electromagnetic disturbance of communication paths. Generally, these and any other issues can be addressed by carefully siting the wind turbines.

The land area required for a wind development is larger than that for other Clean resources such as small hydro; however, other land use activities can coexist with wind development. Some of the sites in the database are on forest land, and issues related to the forest industry would need to be addressed before wind development could proceed.

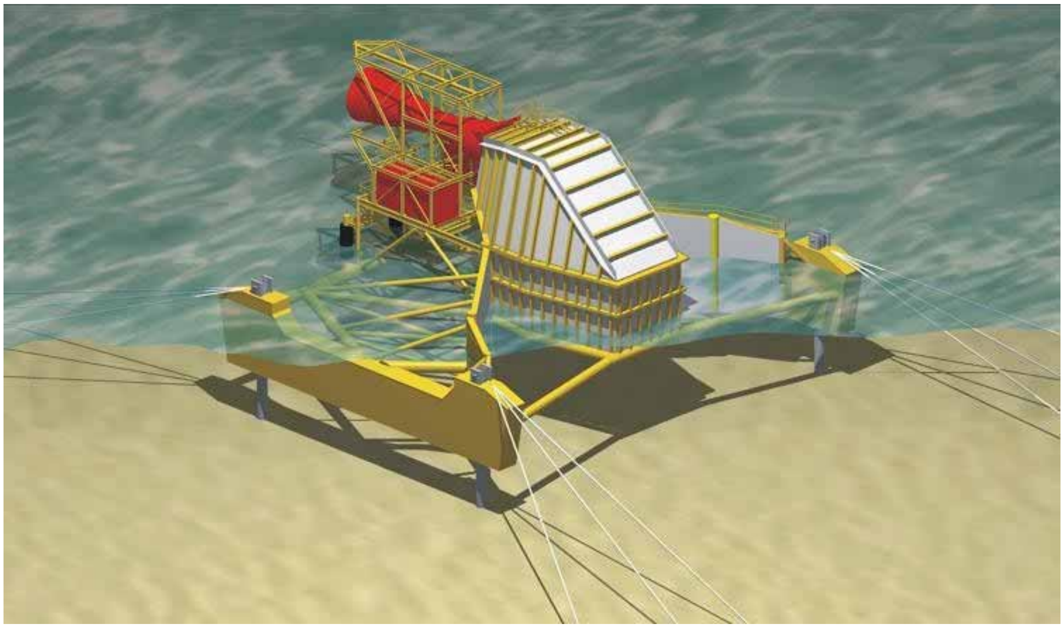
5.1.5. Wave

Ocean wave energy generation is an emerging technology in electricity generation. Ocean wave energy technologies capture the energy of waves and convert the energy to electricity. Geographic locations with the best wave resource are generally those in the mid to high latitudes, including the coastline of British Columbia. The potential wave resource in B.C. is much greater in the winter than in the summer months; this complements BC Hydro's energy demand pattern, which peaks in winter months.

Several different technologies are under development. Currently around the world, wave energy projects that are operating around the world are of the oscillating water column (OWC) type. These projects are generally research related and aimed at demonstrating the technology (Figure 5.6). There are no utility-scale wave developments installed anywhere in the world.

The OWC technology has a two-way turbine that is driven by the compression of air created by the up and down motion of waves, within a concrete caisson. Other technologies include hydropiezoelectric, wave run up (tapered channel) and sea-clam. An example of this technology is the Energetech wave device, which consists of a buoyant structure that is floated into place and moored down under tension, so that it rests on the seabed on four legs (unattached to the seabed).

Figure 5.6. Energetech Ocean Wave Oscillating Water Column



Wave Results

Two potential sites, at Ucluelet and Winter Harbour, have been studied and included in the database. This is not an exhaustive list of potential sites, but these two are considered the best in B.C. that are near load and transmission corridors. Each site has over 100 MW of potential wave power installed capacity and total annual energy of about 600 GWh per year. Cost estimates are based on Energetech's oscillating water column (OWC) technology and were updated for the IEP study by personal communication. An estimate of $100/MWh was included in the database for future evaluation purposes (Table 5.1).

In addition, the cost of emerging technologies, including wave, is expected to decline over the 20-year time frame of the 2004 IEP study. Cost reductions will come primarily from technology development and economies of scale as the industry matures.

Table 5.1 Wave Energy Supply Summary

Project Name	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	**Unit Energy Cost ($/MWh)**	**Unit Energy Cost Range ($/MWh)**
Ucluelet Wave Energy Development	100	300	100	90 - 160
Winter Harbour Wave Energy Development	100	330	100	90 - 160

Wave Impacts

The main concerns about the use of oscillating water columns are disturbance of the marine habitat during construction and visual or aesthetic concerns. The structure has a minimal environmental footprint, can be relocated or taken away, and does not extend to the seabed (other than with the four legs), so sediment transfer can still occur. The seabed area that is disturbed is small and the coast off Ucluelet and Winter Harbour is rocky, so disturbances of marine habitat are not expected to have a negative effect. The structure itself becomes an artificial reef and supports marine fauna, as evidenced by the increase in such life around existing OWC structures. Another potential issue is the impact on marine traffic. Careful siting of the structures is required to mitigate this potential impact.

5.1.6. Tidal Current

The energy inherent in coastal tides can be harnessed in several ways to produce electricity. Tidal barrages (or low dams) have been used in bays or estuaries to store water from high tides for release through hydraulic turbines during lower tides. These systems take advantage of large tidal ranges, such as those in the Bay of Fundy. Tidal barrage systems, however, have high financial costs and potentially significant impacts to the environment.

Tidal current energy, on the other hand, is derived from the flow of coastal ocean waters in response to the tides. Large tidal currents do not necessarily require a large tidal range. Two important factors that influence the magnitude of tidal currents are the phasing of the tides (location and timing of high and low tides) and the presence of narrow passages (concentration of tidal flow).

In British Columbia, some of the highest-velocity tidal current flows occur through the passages between the Strait of Georgia and Johnstone Strait. The tidal range is moderate (five metres), but the tides from the Pacific through Johnstone Strait are roughly 180 degrees out of phase with the tides entering the Strait of Georgia from the southern end of Vancouver Island. This phase difference may mean that tidal currents in BC could provide a more consistent source of electricity than typically provided by single-phase tidal projects.

Although tidal current energy has not yet been commercially developed anywhere in the world, several technologies could realize the potential of this resource. Each technology has a turbine or flow concentrator installed in the tidal stream. The energy in the flowing tide is transferred to a turbine, then converted to electricity by a generator. Some designs are similar to wind turbines, with fixed blades that rotate in the current. Another design consists of a self-contained, moderately buoyant turbine/generator that is suspended like a kite within the tidal stream. A Canadian company is developing an ultra-low-head underwater device that can extract energy from high currents. Another completely different approach uses the pressure differential in a venturi flume to drive a fluid (air or water) through a conventional pipeline turbine that can be located on the shore.

Tidal Current Results

The tidal current resource in B.C. is world-class. Over 50 sites with current speeds over two metres per second have been identified. Twelve sites yielded a total energy production of 2,700 GWh per year. The number and capacity of potential tidal current sites could increase as the application of the technology is advanced.

Because tidal current technologies are in the early stages of research and development, the energy production and cost estimate data are limited and have a high degree of uncertainty compared with those for the other resources. Case studies of two very different sites were conducted to produce a projection of what the resource might cost to develop. Discovery Passage near Campbell River was estimated to be able to accommodate an installed capacity of 800 MW, producing approximately 1,400 GWh per year. Installed capacity of 8.7 MW at Race Passage, located 20 kilometres southwest of Victoria in Juan de Fuca Strait, was estimated to produce 76 GWh per year. Production costs, though very preliminary, are displayed in Table 5.2. As tidal current technology develops, it is possible that the expected cost of generation would decrease.

Table 5.2. Tidal Current Unit Energy Cost Estimates

Project Name	Installed Capacity (MW)	Average Annual Energy (GWh)	Unit Energy Cost ($/MWh)	Unit Energy Cost Range ($/MWh)
Discovery Passage South Tidal Project	800	1,390	150	140 to 240
Race Passage Tidal Project	43	76	360	320 to 580

The cost of emerging technologies including tidal current is expected to decline over the 20-year time frame of the 2004 IEP study. Cost reductions will come primarily from technology development and economies of scale as the industry matures. As the technology is developed and the resource better defined, the costs are expected to decrease.

Only about five per cent of the installed capacity of a single tidal current installation can be considered dependable because during slack tide no energy is produced. However, tidal current energy peaks at different times along the coast, so while one project would experience slack tide, another project farther along the coast would be producing energy. A number of tidal current projects viewed as one system would have a higher dependable capacity. The advantages of tidal current energy are that it is regular and predictable. In addition, the same technologies being developed for tidal current energy could also be used for in-stream flow in rivers. The in-stream energy resource in B.C. has not been assessed.

Tidal Current Impacts

The environmental and socio-economic impacts of tidal current energy depend on location and specific physical site characteristics. Limiting these impacts would be a key consideration in siting, design and construction of each system. The effect of a tidal current development on the tidal regime is estimated to be low locally and negligible globally. Air quality impacts would also be negligible, with no greenhouse gas emissions. The main impacts would be on fish and marine mammals and on navigation and fishing operations. These impacts would depend on the technology used and the site development characteristics, and would require investigation on an individual basis.

5.1.7. Solar

Solar energy can be converted into other forms of energy, such as heat (e.g., for water heating) or electricity. Solar photovoltaic technology is the direct conversion of sunlight into electricity by solid state semi-conductor diodes called photovoltaic cells. A single photovoltaic cell produces only a few watts, so solar photovoltaic modules comprise several cells laminated into a single unit.

Canada’s photovoltaic market is still dominated by remote applications where photovoltaic energy is more cost-effective than operating diesel generators or extending the utility grid. In 2000, 1.5 MW of modules were sold in Canada; of that, only two per cent were installed in grid-tied applications. Although the $42 million photovoltaic industry in Canada is a small fraction of the world-wide $1.6 billion market, growth in Canada has kept pace with the rest of the world and module sales have increased by more than 20 per cent per year on average over the past 10 years.

A rapidly growing opportunity for photovoltaic applications lies in using photovoltaic modules in place of conventional building materials. These building-integrated photovoltaics (BIPV) reduce the overall cost of solar electricity by replacing the building material and providing other benefits such as acoustic and thermal insulation. BIPV can be used in a building in many ways. BIPV roofing incorporates solar cells into conventional roofing products such as tiles or metal roofing. Glass-based BIPV modules may be used in atria to replace overhead, semi-transparent glazing, or in sunspaces, greenhouses and medium to large skylights. Curtain walls represent an even larger market for BIPV modules.

The potential for solar energy in B.C. is not as great as in other locations such as the western United States. For example, Vancouver receives about two-thirds of the solar energy received by San Diego, California. The difference is mainly due to the high degree of cloud cover in B.C. during the winter, rather than the more northerly latitude of B.C. The fluctuation in seasonal weather patterns in B.C. weather produces large variations in the solar energy resource between summer and winter.

Barriers to the adaptation of photovoltaics in B.C. relate primarily to the high cost of the energy resource, and the availability and location of appropriate sites with sun exposure.

Solar Results

Table 5.3 presents a summary of solar energy results. The total potential generating capacity from residential BIPV on detached or semi-detached homes in British Columbia was estimated at 280 MW. However, due to the unfavourable economics of using solar electricity in British Columbia, an assumed uptake of 2.5 per cent of consumers with suitable sites leads to a potential generating capacity of 7 MW, which would produce approximately 7 GWh per year.

The maximum potential generating capacity from BIPV on commercial buildings in B.C. was estimated at 160 MW. Assuming an uptake of 2.5 per cent leads to a potential generating capacity of 4 MW. This would produce approximately 2.6 GWh per year.

The cost of BIPV is very high when compared with most other renewable energy applications, ranging from between $400 and $700 per MWh for commercial applications to between $900 and $1000 per MWh for residential applications. The cost of emerging technologies such as solar energy are expected to decline over the 20-year time frame of the 2004 IEP study. Cost reductions will come primarily from technology development and economies of scale as the industry matures.

Table 5.3. Solar Energy Results

Project Name	Installed Capacity (MW)	Average Annual Energy (GWh)	Unit Energy Cost ($/MWh)	Unit Energy Cost Range ($/MWh)
Commercial – Maximum Potential	160	104	750	680 to 1,000
Commercial – Early Adopter	4	2.6	690	620 to 960
Residential – Maximum Potential	280	280	1700	1,500 to 2,400
Residential – Early Adopter	7	7	1500	1,400 to 2,100

Note: Unit energy cost range displayed is based on price uncertainty rating.

Solar Impacts

BIVP development does not require any new transmission lines or roads because the technology is installed at existing residential or commercial buildings that are already connected to the electrical grid. Photovoltaic modules produce a net benefit to the environment, since the energy used in their production is recovered in two to four years, and the modules continue to produce Clean Energy for 20 to 30 years afterwards. Toxic materials are used in the manufacture of photovoltaic modules, but recycling or reclamation can mitigate the environmental impact of these materials.

5.1.8. Fuel Cells

Fuel cells are electrochemical devices that convert the chemical energy of a fuel directly to usable electricity and heat without combustion, through the electrochemical reaction of fuel and oxidant. Each cell is made up of two electrodes and an electrolyte, similar to a battery. However, unlike a battery, a fuel cell will continue to produce electricity as long as fuel and oxidant are provided from an external source. Fuel cells can be classed as Clean Energy sources in the 2002 B.C. Energy Plan, but this depends on the fuel and emissions.

While the concept of fuel cells has been around for more than 100 years, the first practical fuel cells were developed for the U.S. space program in the 1960s. Because of technology improvements in recent years and significant investment by automobile manufacturers, utilities, NASA and the military, fuel cells are now expected to have applications for distributed power generation within the next few years.

Fuel cells produce electricity at efficiencies of 40 to 60 per cent with negligible harmful emissions, and are extremely quiet. These characteristics, along with their scalability, high efficiency and modularity, make them particularly well suited to the distributed power generation market.

Fuel cells are classified by their electrolyte material. Currently, several types of fuel cells are being developed for applications as small as a cellular phone (0.5 W) to as large as a small power plant for an industrial facility or a small town (10 MW). At present, the only commercially available fuel cell in the 200 kW range that has proven reliability in stationary generation applications is a phosphoric acid fuel cell (PAFC).

Other emerging technologies with significant potential for stationery power generation are the proton exchange membrane fuel cell (PEMFC), solid oxide fuel cell (SOFC) and molten carbonate fuel cell (MCFC). These four types have currently demonstrated the most potential and so are described as future resource options.

The resource option database includes only the fuel cells about which enough information was available to characterize the resource:

- Solid oxide fuel cell (SOFC);
- Proton exchange membrane fuel cell (PEMFC), and
- Phosphoric acid fuel cell (PAFC).

Not enough information was available to include MCFCs.

Fuel Cell Energy and Economics

Present generation systems are limited to 5 to 10 MW. Because this industry is undeveloped, estimates of price per kilowatt installed are limited and depend on the application and the type of fuel cell (proton exchange membrane fuel cells are expected to have a capital cost between US$500 to $1,000/kW, with costs for fuel additional). Descriptions of the fuel cells, energy and economics can be found in Appendix D.

Small-scale, modular fuel cells have been included as a distributed resource option. In future, fuel cells may play a larger role in satisfying supply requirements. In addition, the cost of emerging technologies including fuel cells is expected to decline over the 20-year time frame of the 2004 IEP study. Cost reductions will come primarily from technology development and economies of scale as the industry matures.

5.2. Thermal

B.C. has fossil fuel resources, including natural gas, oil, coal-bed methane (CBM) and coal. The 2004 IEP includes potential projects for electricity generation using these fossil fuels. Projects ranged from specific projects for which pre-feasibility studies have been conducted (e.g., Quinsam Coal) to generic projects based on industry standard information. Projects were described using standard generation unit sizes from under 50 MW to 500 MW, and set in general locations around the province.

B.C.'s oil and gas resources are largely untapped. Table 5.4 lists the volumes of oil and gas that industry analysts estimate could be discovered. Most of the industry's activity is in northeastern B.C., where about 2,800 oil and gas pools have been identified and approximately 13,000 wells have been drilled so far.

About 3,000 gas wells and 1,000 oil wells are currently in operation, with 29 facilities processing natural gas. In 2001, a record 850 oil and gas wells were drilled. About one trillion cubic feet of natural gas and 17 million barrels of oil were produced. Much of this fuel is destined for export to the U.S. Pacific Northwest, the U.S. Midwest states and California. B.C. is also a major supplier of gas to eastern Canada.

Table 5.4. B.C.'s Oil and Natural Gas Potential

Region	Natural Gas (trillion cubic feet)	Oil (billion barrels of oil)
Northeast	50	0.8
Unexplored Basins (Bowser-Nechako and Fernie)	23	7.69
Offshore	42	9.8
Total Resource	115	18

Source: http://www.gov.bc.ca/em/popt/factsheet_oil_gas_resources.htm

Oil and gas exploration and development are advancing in northeast B.C. In F2002, the industry generated more revenue for the province than any other industry.

Several combustion technologies are available that can burn fossil fuels to generate electricity. Table 5.5 describes some common technologies.

Table 5.5. Thermal Turbine Technologies

Conventional Steam Turbines	Conventional steam turbines burn the fuel in a boiler to heat water, which creates steam to drive a steam turbine.
Simple- and Combined-Cycle Combustion Turbines (SCGTs and CCGTs)	Combustion turbines are based on jet engines. In a combustion turbine, the fuel is burned under pressure to produce hot exhaust gases, which spin a turbine to generate electricity. Simple-cycle configurations release exhaust gases to the atmosphere. In a combined-cycle configuration, the exhaust gases from the gas turbine are directed to an unfired Heat Recovery Steam Generator (HRSG), producing steam for steam turbine generators.
Internal Combustion Engines (Reciprocating Engines)	An internal combustion or reciprocating engine converts the energy contained in a fuel into mechanical power. This mechanical power is used to turn a shaft in the engine.
Cogeneration Technologies	Cogeneration involves thermal power generation and a steam/thermal "host" to use the excess heat produced from the generating process. Steam/thermal hosts may include industries and institutions that need heat such as pulp mills, greenhouses or hospitals.

These combustion technologies can use a variety of fossil fuels. For example, a conventional steam turbine can be fuelled by coal, oil, natural gas or coal-bed methane. Table 5.6 presents some common pairings of fuel type to thermal generation technologies.

Table 5.6. Fuel Type and Combustion Technology Matrix

Fuel type	Technology: Conventional Steam Turbine	Simple Cycle Combustion Turbine	Combined Cycle Gas Turbine	Internal Combustion Engine	Cogeneration
Coal	✓				✓
Fuel Oil	✓	✓		✓	✓
Diesel		✓	✓	✓	
Natural Gas	✓	✓	✓	✓	✓
Coal-Bed Methane	✓	✓	✓	✓	✓

The 2004 IEP categorizes thermal resource options from a fuel perspective, selecting fuel-technology matches to determine air emission factors for thermal resource options. The following combinations of fuel and technology were characterized and included in the database, based on the best available data at the time of study:

- Natural gas
    - Simple- and combined-cycle gas turbines
    - Internal combustion engines
    - Cogeneration
- Coal
    - Conventional steam turbine (pulverized, subcritical)
- Fuel oil
    - Simple-cycle combustion turbine
    - Mobile combustion turbines
- Diesel
    - Internal combustion engines

5.2.1. Natural Gas

Natural gas is broken down into two broad categories depending on the source. Conventional natural gas accompanies oil deposits, whereas coal-bed methane is found in coal deposits. Natural gas is formed as a direct result of “cooking” oil at high temperatures; the longer hydrocarbon chains (oil) begin to break down into shorter chains (natural gas) at roughly 200 degrees Celsius (400 degrees Fahrenheit).

True natural gas out of the ground varies in composition, but a representative mix is roughly 83 per cent methane, 8 per cent ethane, 4 per cent propane, 1.7 per cent n-butane and various other trace elements. After processing for commercial and residential applications, it is composed almost entirely of methane.

Natural gas is also produced industrially as a by-product of the refining of fossil fuels. Historically, this by-product was flared (burned) on site, as is still the practice in many regions of the world. However, as natural gas is being realized as a cleaner alternative to other fossil fuels, the trend is now to capture and use it rather than waste it.

There are varying industry perspectives on how future natural gas supply and demand will unfold and, consequently, uncertainty about future gas prices. Generally, most industry experts believe that North America's long-term natural gas supply markets will respond to price levels to meet future demand and will adjust for declining traditional natural gas supplies through several major developments. These include development of coal-bed methane, development of new natural gas areas (e.g. Arctic and offshore) and development of liquefied natural gas (LNG) facilities to import natural gas from other parts of the world.

Because there is future gas price uncertainty, BC Hydro does not rely on a single natural gas price forecast for longer-term electricity planning purposes. Rather, BC Hydro uses a scenario-based approach employing a range of future natural gas prices that are derived from publicly available sources. BC Hydro develops price forecasts for natural gas based on five market scenarios. The four that are based on natural gas prices are shown in Table 5.7. Part 5 provides details on the development of the forecasts presented in Table 5.7 and Figure 5.7.

Table 5.7. Natural Gas Prices (Sumas - $CDN/GJ)

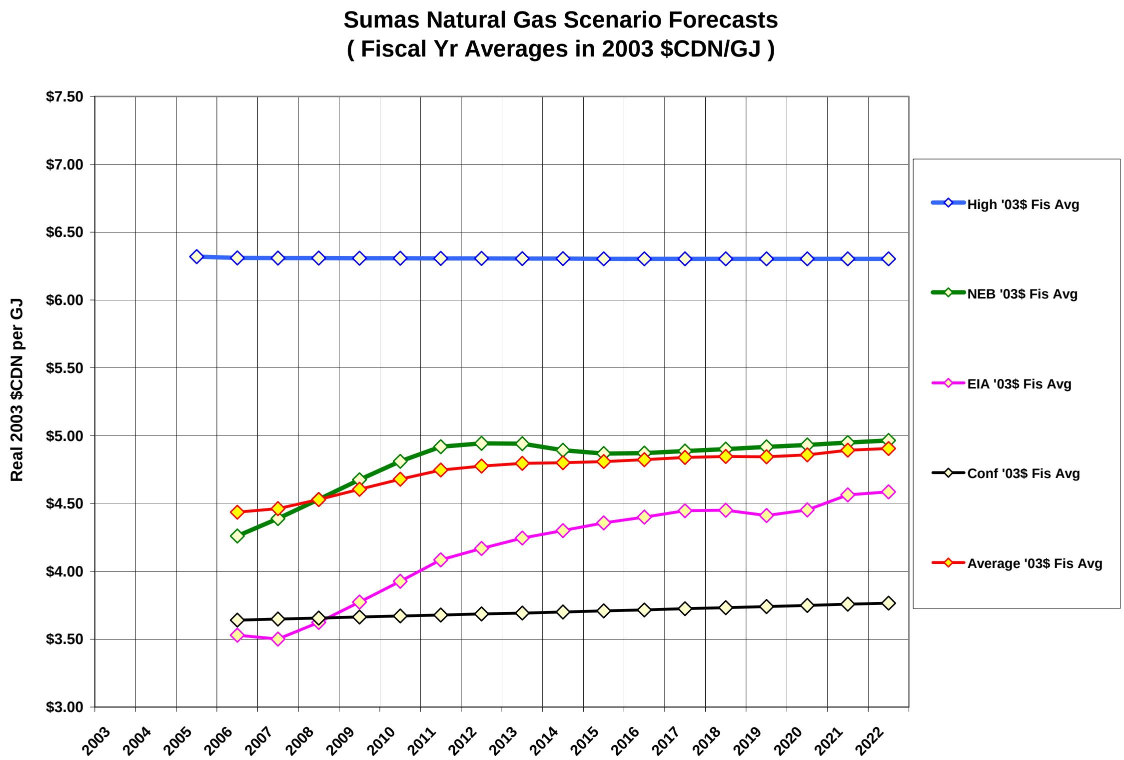
Gas Price Forecast Case			
High Gas	EIA	NEB	Confer
$6.3	$4.0	$4.9	$3.7

Notes:

1. Levelized in Real 2003 dollars over 15 years from earliest operating year.
2. A base exchange rate for the Canadian dollar of 0.75 $CDN = 1.00$US was used for price conversions.

An average of the four scenarios was used to create a representative case for natural gas prices and electricity forecasting in the Resource Option database. The High Gas case is considered an upper limit for worst case scenario analysis, and was also included in this average representative case. A levelized price for natural gas of $4.8/GJ was used in unit energy cost estimates as it was assumed that a large natural gas plant (different from the Vancouver Island Generation Project) would not come on-line until sometime after 2008.

Figure 5.7 Natural Gas Price Forecast (Sumas)



Conventional Natural Gas Options

This section describes four generic natural gas plants assumed to be located at new and unidentified, or “greenfield,” sites. These plants are non-site-specific, but are assumed to be located near a natural gas pipeline. The generic projects included in the resource option database were a representation of what would be expected for a new plant from a financial, technical and economic basis in the typical configurations described below

The preferred methods for generating electricity from natural gas are through the use of simple-cycle gas turbines (SCGTs) or combined-cycle gas turbines (CCGTs).

In simple-cycle technology, the generation of electricity from natural gas occurs as follows:

- Natural gas is burned in a combustion turbine;
- Thermal energy is converted into mechanical rotational energy within the turbine; and
- Mechanical energy is converted into electricity in a generator.

In combined cycle technology, the waste heat from the combustion turbine is captured and converted into supercritical steam by a heat recovery steam generator (HRSG). Expanding this steam through a steam turbine generator set provides a second stage of electricity generation. SCGTs are used to meet peaking requirements; CCGTs are more complex and costly, but run more efficiently and are more suitable to meet baseload energy requirements.

Greenfield Simple-Cycle Gas Turbine Plant

This project assumes a 47 MW (nominal) simple-cycle gas turbine. This General Electric turbine is the industry standard for SCGT plants; larger capacity plants use multiple GE LM6000 units.

Greenfield Combined-Cycle Gas Turbine Plant

Key data for the three power plant configurations were included in the database as follows:

- 60 MW – The project consists of a CCGT (LM6000 1x1x1)[5] with nominal net output of 57 MW.
- 250 MW – The project consists of an F Class 1x1x1 combined cycle gas turbine configuration with nominal net output of 250 MW.
- 500 MW – The project consists of an F Class 2x2x1 combined cycle gas turbine configuration with nominal net output of 500 MW (2x2x1 indicates there are two gas turbine gensets, two HRSGs and one steam turbine).

Unit energy costs for the 60 MW project were estimated using the same assumptions as other thermal projects (coal, oil, diesel). Unit energy costs for the 250 MW and 500 MW CCGT were estimated based on the BC Hydro price forecast and project assumptions, but using an 91.3 per cent assumed dispatch rate to be consistent with other thermal resource characterization. The modelling used assumptions the would be typical for an IPP.

Figure 5.8 displays the relative unit energy cost estimates for thermal resources. Unit energy cost estimates for natural gas projects are illustrative and may be updated through modelling and evaluations of costs and fuel price forecasts. See Appendix E for further details about these resource options.

Vancouver Island Generation Project

In 2003, Vancouver Island Energy Corporation (VIEC), a wholly owned subsidiary of BC Hydro, applied to the BCUC for permission to build and operate the Vancouver Island Generation Project (VIGP), a natural gas-fired CCGT.

The VIGP represented in the resource option database as two projects; the first with the cost estimates and financial assumptions provided by VIEC to the BCUC, and the second as an evaluation employing assumptions recommended by the BCUC in its decision on the VIGP hearing.

[5] 1x1x1 refers to one natural gas turbine genset, one HRSG and one condensing steam turbine genset.

Figure 5.8 Relative Unit Energy Cost Estimates - Thermal Resources

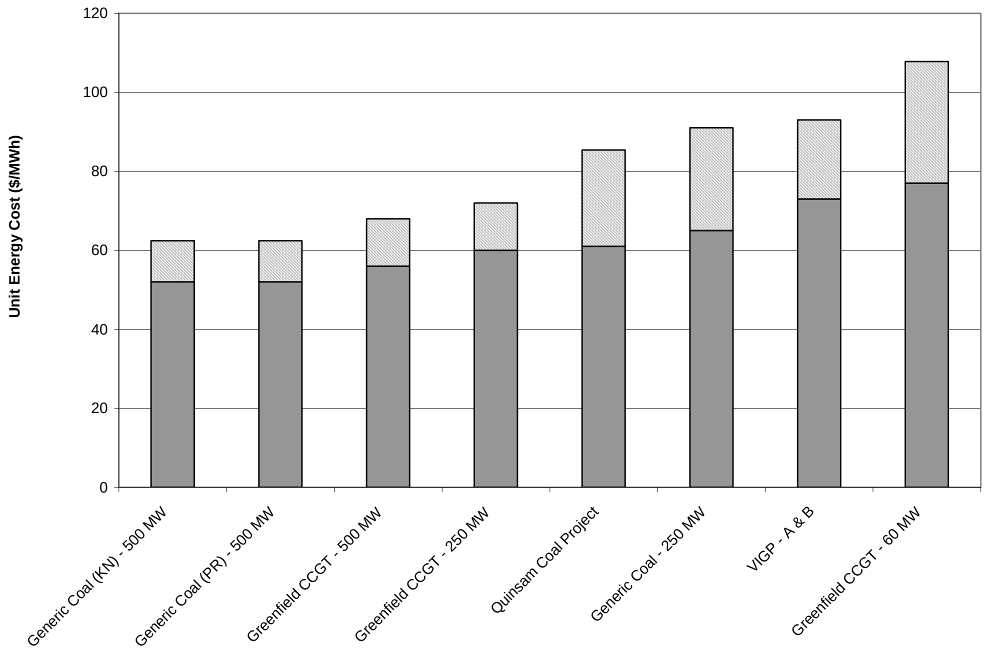


Figure Notes: Lighter sections represent price uncertainty. Coal, oil and diesel price uncertainty was estimated based on level of study and information available. Price uncertainty for natural gas projects, including VIGP, was based on the four gas price scenarios.

The project’s installed capacity is either 265 MW or 295 MW, depending on whether duct-firing is used. BC Hydro planned to employ duct-firing technology, and the cost estimates reflect this assumption.

Previous estimating exercises by VIEC and BCUC indicated that unit energy costs for the project would be in the range of $73/MWh to $93/MWh, depending on the analysis, financial assumptions, fuel transport and toll assumptions and value of the Canadian dollars.

NorskeCanada Natural Gas Cogeneration

During the VIGP hearing, NorskeCanada put forward a proposal for a suite of energy projects at its Vancouver Island facilities that could provide a total winter power capacity of approximately 364 MW.

NorskeCanada also indicated its interest in the BC Hydro’s Vancouver Island call for tenders by registering these projects into the call. The resource option information included in this report reflects information made public through the VIGP hearing. As part of the NorkseCanada Energy Project (NCEP), NorskeCanada proposes to install new electric power facilities at its Crofton, Port Alberni and Elk Falls pulp and paper mills on Vancouver Island. The equipment and installed capacity of each project is described in Appendix E and summarized below:

- At its Crofton mill located near Duncan, NorskeCanada proposed to install a cogeneration system, including two gas turbines (92 MW) and one condensing steam turbine (15 MW), for a total addition of 107 MW.
- At its Port Alberni mill, NorskeCanada proposed to install one gas turbine, for a total of 46 MW.
- At its Elk Falls mill located north of Campbell River, NorskeCanada proposed to install a cogeneration system, including two aeroderivative gas turbines (92 MW) and one condensing steam turbine (12 MW), for a total addition of 104 MW.

The NorskeCanada projects, as presented in the VIGP hearing, were included in the database. See Thermal (Natural Gas), in Appendix E.

Natural Gas Internal Combustion Engines

Internal combustion engines were included as a resource option to reflect the potential that these stand-alone, small diesel-type engines could be used at a small scale for distributed generation.

Reciprocating or internal combustion engines are the most common and technically mature of distributed energy technologies. They are available from small sizes (e.g., five kW for residential back-up generation) to large generators (e.g., 7 MW). When used in combination with a one to five minute uninterruptible power supply, the system is able to supply seamless power during a utility outage. In addition, large internal combustion engine generators may be used as baseload, grid support or peak shaving devices.

An internal combustion engine converts the energy contained in a fuel into mechanical power, used to turn a shaft in the engine. A generator attached to the engine converts the rotational motion into power.

Depending on the application, natural gas, diesel or fuel oil may be used to fuel an internal combustion engine. Natural gas-fired and diesel-fired engines were selected for characterization in the database. Each fuel type has advantages and disadvantages. Natural gas is usually less expensive than diesel fuel for the same heat content. If the internal combustion engine is to be used for a large number of hours per year, the total cost to operate the gas unit may be lower. Natural gas may not be available at all locations, while diesel can be transported anywhere. However, diesel engine emission levels are higher and their use is significantly restricted in some areas. Issues regarding liquid fuel storage would need to be resolved for diesel. Fuel oil-fired internal combustion engines may be inexpensive to operate, but tend to have higher emissions than diesel-fired engines. Unit energy cost estimates for smaller thermal generation projects are included in Table 5.8.

Table 5.8. Small Thermal Generation Unit Energy Cost Estimates

Project Name	Installed Capacity (MW)	Average Annual Energy (GWh)	Unit Energy Cost ($/MWh)	Unit Energy Cost Range ($/MWh)
Simple Cycle Gas Turbine – 47 MW	47	78	110	100 to 130
Natural Gas-Fired internal combustion Engines	7	12	170	150 to 210
Oil Fired Simple-Cycle Combustion Turbine	42	70	130	120 to 230
Mobile Oil Distillate Generators	161	39	N/A	N/A
Diesel-Fired internal combustion Engines	7	12	200	180 to 250

Note:

1. A dispatch rate of only 20% was assumed for these peaking plants, making unit energy costs quite high.
2. Values are rounded to two significant figures.
3. N/A: not applicable. The mobile generators were assumed to be solely for backup capacity, and would only be run approximately 10 days per year, making unit energy cost calculations not comparable and quite high.
4. Average annual energy and unit energy costs were not provided by NorskeCanada for its proposed projects; therefore, they were not included.
5. Price ranges are based on price uncertainty rankings and do not incorporate uncertainty in the price of fuel.

Coal-Bed Methane

Coal-bed methane (CBM) is the natural gas found in most coal deposits. CBM is created when plant material is converted into coal over millions of years. Under most circumstances, CBM consists of pure methane. It may also contain carbon dioxide, nitrogen and very small quantities ethane and propane.

The use of CBM is in its infancy in Canada and to date there is little or no information on commercial production or applications in this country. However, there is considerable knowledge of the make-up and analysis of CBM as a fuel, and a number of existing thermal plant technologies could use CBM for electricity generation. These include firing in conventional gas-fired boilers and as a sole fuel, or mixed with natural gas for combined-cycle gas turbine and diesel/natural gas dual-fuel engine generators.

CBM potential is present in many areas in British Columbia, including parts of Vancouver Island and the Interior, the Northeast and the Southeast of the province. The exploration and development of coal-bed methane in British Columbia is currently being investigated by the private sector and the Ministry of Energy and Mines to estimate reserves, economic impact, regulatory requirements and environmental impacts.

CBM has not been included in the database as a fuel option. However, BC Hydro will continue to monitor the development of this fuel.

Environmental Issues

Because CBM typically approaches pipeline quality upon production, has fewer impurities than coal, oil or conventional natural gas, and does not require extensive processing, it can reduce the impacts on local air quality when displacing conventional thermal fuel sources such as gas, coal and oil. However, it does contribute to greenhouse gas emissions.

The production of CBM may involve large quantities of water. To make CBM flow, the natural pressure in the coal seam must be decreased by de-watering the coal. A pump located at the wellhead removes the water that naturally occupies the coal seam. This lowers the pressure along the coal seam, draws the gas out of the coal and allows it to flow into the well bore. Effective de-watering may take anywhere from several months to several years.

Water quality, treatment and disposal methods are the key impacts of CBM development. Depressuring the coal seam may generate large volumes of water of varying quality. Generally, this water would be tested for quality and disposed of through surface drainage or ponds to seep back into the soil or evaporate naturally, or be re-injected into the ground. The B.C. Oil and Gas Commission, in consultation with the Ministry of Water, Land and Air Protection, reviews the water quality issues and discharge options on a case-by-case basis.

5.2.2. Cogeneration

Cogeneration was included in the appropriate resource category according to the base fuel used for the thermal generation (e.g., natural gas or biomass), rather than as a separate resource type.

Cogeneration, also termed combined heat and power (CHP), is the simultaneous production of electrical and thermal energy from a single fuel. Cogeneration involves thermal power generation and a steam/thermal host to use the excess heat produced from the generating process. Steam/thermal hosts may include industries and institutions that need heat, such as pulp mills, greenhouses or hospitals.

A range of technologies and fuels can be used for cogeneration, including biomass, municipal solid waste, biogas and fossil fuels. There are opportunities to incorporate cogeneration into existing systems near a thermal host by:

- Adding a generator to heating/cooling systems; or
- Developing a stand-alone generation plant.

The efficiency of conventional generation of electricity in large thermal power stations is normally only 30 to 40 per cent (55 per cent at the most), excluding transmission losses. These conventional electricity-only stations release large amounts of energy as waste heat. By using the waste heat in a process that requires heating, the efficiency of a cogeneration plant may reach 90 per cent or greater. This 35 to 60 per cent gain in efficiency is a direct result of using the waste heat that would otherwise typically be provided by natural gas.

Although cogeneration is not considered green when fuelled by fossil fuels, it provides a net environmental improvement compared to conventional thermal energy because of the efficiency gain. The B.C. Energy Plan defines cogeneration as B.C. Clean.

Cogeneration Potential Assumed in the 2004 IEP

Cogeneration potential for B.C. was estimated in a national study for Natural Resources Canada in April 2002. This study focused on cogeneration using natural gas as a fuel, although some biomass-fired cogeneration was also included. A summary of the relevant data from this study is provided in Appendix E.

Cogeneration opportunities in B.C. have typically used biomass (woodwaste, biogas, municipal solid waste) as fuel because it is a low-cost fuel with a stable, predictable price. Given the voluntary 50 per cent Clean target from the new B.C. Energy Plan, it is possible that more biomass cogeneration capacity will be added in the B.C. Interior in the next few years. The resource option database includes 105 MW from these biomass cogeneration projects. See Appendix D for details.

The resource option database includes the NorskeCanada Crofton and Elk Falls facilities cogeneration components with approximately 27 MW of cogeneration in condensing steam turbines (15 and 12 MW respectively). See Appendix E for details regarding these cogeneration projects.

Maxim Power Corporation provided estimates of cogeneration potential in B.C. at the VIGP hearing. Maxim suggests that there may be 370 MW of small-scale cogeneration opportunities using natural gas in the Lower Mainland and Vancouver Island at universities, hospitals and greenhouses, at a price of $70 to $75 per MWh, if BC Hydro is willing to take the gas price risk.

Natural gas-fired cogeneration projects face some economic challenges in B.C., including the high capital cost of new high-pressure boilers that are often required to maximize power production, and the uncertainty associated with natural gas prices. Therefore, natural gas-fired cogeneration beyond specific projects identified (e.g., NorskeCanada) was not included in the 2004 IEP.

Power Smart programs include an estimate for expected energy savings from load displacement, energy efficiency or self-generation projects that may be classified as cogeneration. The Power Smart 2 program also includes an approximate estimate of 100 MW of cogeneration potential at various industrial facilities across B.C. See Appendix B for details regarding these Power Smart programs.

In summary, the 2004 IEP resource options include estimates for a cogeneration potential of 232 MW, as follows:

- Biomass cogeneration projects (105 MW);
- NorkseCanada projects (27 MW); and
- Power Smart 2 (100 MW).

These projects leave the unaccounted potential of approximately 50 MW in the “business as usual” cogeneration forecast for the year 2015 in the Natural Resources Canada study. Therefore, there may be approximately 50 MW of potential for new small-scale, natural gas-fired cogeneration not identified in the resource option database. However, this 50 MW is counted as follows:

- Power Smart 3, 4 and 5 assumes some capture of additional cogeneration opportunities, which may account for all or some of the unaccounted potential.

- Existing cogeneration projects that have been implemented since the Natural Resources Canada estimate (Vancouver Iona, Kelowna Riverside, Mackenzie Abitibi and others).

B.C.-specific studies are being conducted to define the cogeneration potential in B.C. more accurately, and results will be incorporated into subsequent IEPs.

5.2.3. Coal

British Columbia has large thermal coal reserves in the East Kootenays, Hat Creek (Clinton area), Peace and Vancouver Island areas. In the scenario of forecast natural gas supply constraints, coal may play a larger role in the next round of power plant construction in North America.

Coal resource options included in the 2004 IEP are as follows:

- A generic 250 MW mine-mouth pulverized coal conventional steam station located in the East Kootenays;
- A generic 500 MW mine-mouth pulverized coal conventional steam station located in the Peace Region;
- A generic 500 MW mine-mouth pulverized coal conventional steam station located in the Clinton area to represent the Hat Creek resource; and
- The 60 MW Quinsam coal project on Vancouver Island, as presented in the VIGP hearing.

The 250 MW and 500 MW plants were assumed to use a pulverized coal-fired unit of subcritical steam cycle a common industry design. Coal gasification technology is advancing and could be employed to reduce emissions and increase flexibility in fuel supply.

BC Hydro developed the data to describe the mine-mouth options based on results from other IEPs in the Western Electricity Co-ordinating Council. The results were then reviewed by the engineering firm of Black and Veatch Corporation (BVC).

Unit energy prices for coal are expected to range from \$45/MWh to \$70/MWh, with an average of approximately \$55/MWh, based on examples from Idaho, PacifiCorp and Puget Sound. More specific coal unit energy prices using a coal price forecast specific to British Columbia are included in Appendix E. Environmental information including estimates for local air emissions and GHG's are also included in Appendix E.

In the VIGP hearing, Quinsam Coal, a wholly owned subsidiary of Hillsborough Resources Limited, proposed a 60 MW coal-fired generation project on Vancouver Island. In their review of project costs, BVC advised that the cost estimates appeared to be low. This may be due to the plan to use used equipment or due to lower coal generation operating costs in B.C. versus the U.S.. SNC Lavalin Inc. indicated that U.S.-based cost estimates are higher than the estimated cost for plants to be built in Canada, with labour costs and productivity being significant factors. The recent appreciation of the Canadian dollar also helps to reduce the cost of plants built in Canada as many major components are likely to come from the U.S. Quinsam Coal was included in the resource option database, with operations and maintenance estimates provided by BVC.

Coal Gasification

Advancements in coal gasification technology combined with natural gas price volatility have renewed interest in coal-fired generation plants. Research studies investigating "clean coal" technology continue, and typically involve coal gasification and carbon sequestration (or storage). The gasification process involves converting coal to combustible gases (primarily carbon monoxide and hydrogen, called syngas), using steam and oxygen/air under high temperature and pressure conditions.

For electricity generation applications, integrated gasification combined cycle (IGCC) is a component of "clean-coal" technology. IGCC incorporates steam and gas turbines with the gasification process. The gas turbine is fuelled by the syngas, and the steam produced from burning the syngas is then used to generate the superheated steam that drives the steam turbine. IGCC is able to use a variety of feedstocks, including biomass, to produce syngas.

By-products of the gasification process include hydrogen sulphide, ammonia, mercury, carbon dioxide and other trace metals (dependent on coal composition). Carbon dioxide can be separated from the product gases and stored or buried. Storage possibilities for carbon dioxide include sequestration in depleted oil and gas reservoirs and deep saline aquifers, although the safety, permanence and effectiveness of sequestration has not been proven.

This gasification system, when carbon sequestration is included, is more of a closed loop system that produces less particulate than a traditional coal-fired electricity plants, and is thus termed "clean coal."

Other Coal Technologies

Other advanced coal-fired technologies offer higher thermal efficiency, improved control of air emissions and reduced water consumption. These include supercritical steam cycles and atmospheric fluidized-bed combustion.

Supercritical units are more commonly used in Europe and Japan than in North America because the North American installations of the 1960s and '70s have had a poor reliability. Atmospheric fluidized-bed technology is in commercial use, but has been generally limited to smaller units using waste or low-grade coal. Coal gasification has been commercially employed in the petrochemical industry, but electric power applications are in the demonstration phase.

In the 1990s, the generally superior competitive position of natural gas has been a major factor impeding more widespread adoption of advanced coal technologies. If more aggressive attempts at reducing carbon dioxide production are made, advanced coal technologies will be increasingly attractive because of superior energy conversion efficiency.

These advanced technologies have not been characterized in the IEP because of limited information. On the other hand, coal-fired conventional steam

generating stations are a mature technology, with many units in North America and other utilities and energy planning jurisdictions using the conventional stations in their planning efforts.

5.2.4. Oil

Oil-fired generation is of interest where natural gas is restricted or unavailable. An oil-fired simple-cycle combustion turbine (SCCT) of approximately 40 MW was included as a resource option in the 2004 IEP and characterized in the resource option database.

The oil-fired SCCT project assumes a General Electric LM 6000PC Aeroderivative gas turbine generator fired on oil distillate fuel (Oil #2). Nitrogen oxide emissions are controlled by water injection into the gas turbine and selective catalytic reduction on the exhaust. Costs for oil distillate fuel are approximately $6/GJ.

The LM6000PC was selected because it is one of the most efficient generators operating in simple cycle. It can be shipped by truck to most locations, including remote sites, and could be operated remotely from a BC Hydro control centre.

In general, simple-cycle plants are most effective when run to meet the peak load, while combined cycle turbines are more effective when run constantly to meet base load energy requirements.

5.2.5. Diesel Internal Combustion Engines

Internal combustion engines were included as a resource option to reflect the potential for using these stand-alone small turbines on a small scale for distributed generation. Internal combustion engines are the most mature and robust distributed generation option currently available. Depending on the application, natural gas, diesel fuel or Bunker C may be used to fuel an internal combustion engine. The previous section on the Natural Gas Internal Combustion Engine describes internal combustion engine technology and its inclusion in the resource option database.

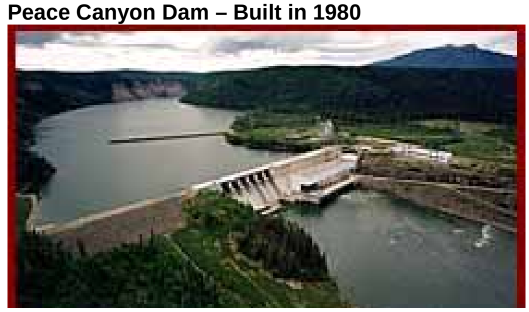
5.3. Large Hydro

Hydroelectric generation harnesses streamflow or falling water, channelling the water down a gradient and into a turbine, which generates current. The distinction between small hydro and large hydro varies, depending on the jurisdiction. At BC Hydro, small hydro is typically classed as under 50 MW, and large hydro is greater than 50 MW. Both class sizes can include run-of-river projects, or projects with storage.

Two technical conditions are required to generate hydroelectric power, and both are readily available in British Columbia:

- A source of flowing water; and
- A change in elevation to provide the water with potential energy.

Peace Canyon Dam – Built in 1980



A good hydroelectric generation site would also have low environmental impact and technical and economic feasibility (e.g., moderate terrain for construction, proximity to a transmission grid). Large hydro has faced increasing regulatory and public pressures due to social and environmental concerns. However, large hydro can provide dependable capacity that might otherwise have to be provided by fossil fuel.

The only significant cost of a hydroelectric power generation system is the capital cost of equipment, installation, design and engineering. The very low maintenance and operations requirements of hydroelectric systems give them an economic advantage. Because hydro systems can be almost completely automated, once they are installed and operational, they need little operator time and security needs are normally limited.

New opportunities for large hydroelectric generation include:

- New hydroelectric generation; and
- Pumped storage.

Hydroelectric generation, including Resource Smart projects on BC Hydro facilities, can provide dependable capacity and energy at a wide range of costs, as shown in Figure 5.9.

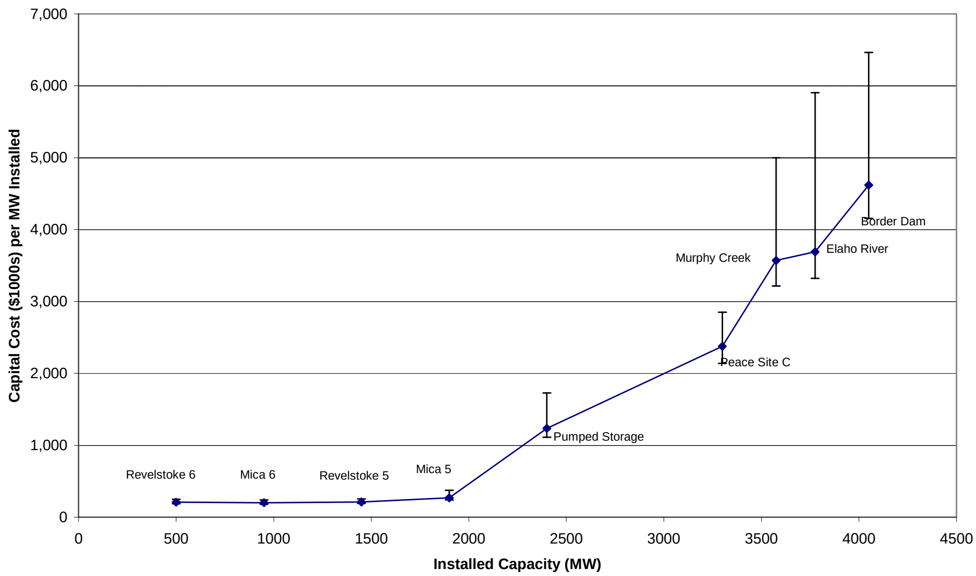
5.3.1. New Hydroelectric Generation

The large hydroelectric resource options considered are summarized in Table 5.9 and their costs in $/MW and $/MWh respectively are depicted in Figures 5.9 and 5.10. 1. Costs per MW represent a division of capital costs by dependable or installed MW, and have not been levelized. New hydroelectric projects in B.C. would likely require provincial cabinet approval.

Table 5.9. Large Hydro Generation Options

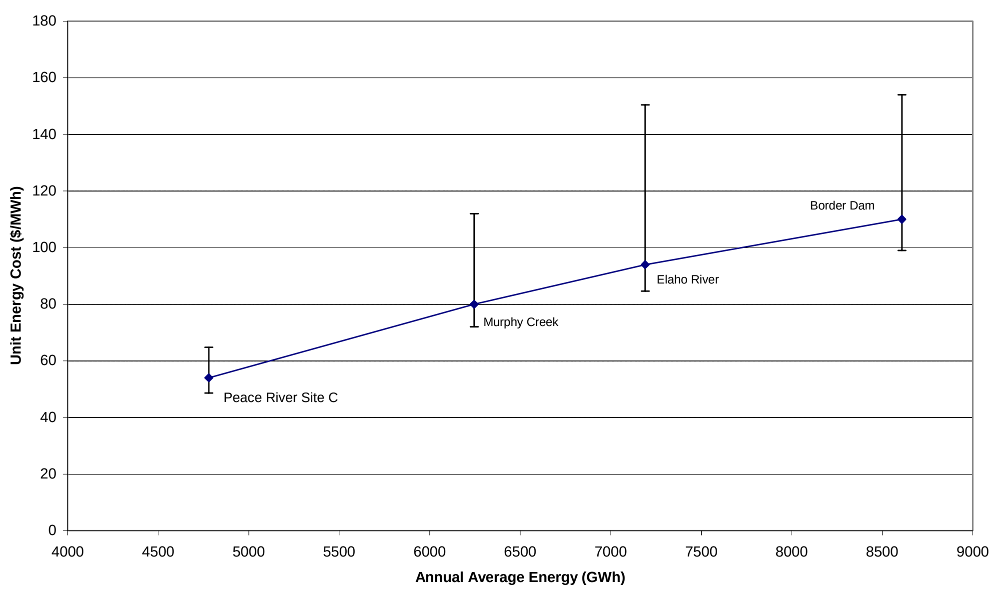
Project / River	Installed Capacity (MW)	Storage or Run-of-river
Site C – Peace River	900	Run-of-river
Border Project – Columbia River	275	Run-of-river
Elaho – Elaho River	200	Storage
Murphy Creek – Columbia River	275	Run-of-river

Figure 5.9. Large Hydroelectric Projects: Capacity Cost Curve ($/MW)



Note: Cost range bands are displayed in the supply curves based on the price uncertainty ratings, and reflect uncertainty in the technical assumptions used to make cost estimates. Price uncertainty does not include uncertainty in market or fuel prices. Additional description of these price uncertainty ratings can be found in Appendix A. New hydroelectric projects not at existing facilities would require provincial cabinet approval.

Figure 5.10. Large Hydro Supply Curve



Note: Cost range bands are displayed in the supply curves based on the price uncertainty ratings, and reflect uncertainty in the technical assumptions used to make cost estimates. Price uncertainty does not include uncertainty in market or fuel prices. Additional description of these price uncertainty ratings can be found in Appendix A.

These large hydro projects were assumed to be developed primarily by the private sector with public or bond debt financing. Unit energy costs for large hydro have been estimated with the financial assumptions described in Appendix A, using the spreadsheet-based model developed for alternative energy cost estimation.

BC Hydro and others have evaluated a number of large hydroelectric generation opportunities to add power to the B.C. system, including an Iskut River project and the Kemano completion project. These and other major hydroelectric development sites were excluded from the 2004 IEP resource inventory because of development challenges or risks, including potential fisheries impacts and locations in protected areas.

In addition to the projects included in the database, two large Columbia River hydroelectric projects have received some attention over the last decade: the Brilliant Expansion and Waneta Upgrades. The Brilliant Expansion has been included in the demand-supply outlook as an “existing and committed” resource because it is underway.

Teck Cominco completed an upgrade to its existing Waneta generating station in December 2002, and expects to complete two more upgrades by the end of 2003. Each upgrade adds 25 MW and up to 75 GWh per year of energy. The exact amount of energy recognized for the upgrades varies with water licence precedence and the number of upgrades completed.

A Waneta Expansion project is under study by Columbia Power Corporation and the Columbia Basin Trust (CPC/CBT). The project would obtain much of its water at the expense of the previous upgrades. If and when it is built, the energy gained by the upgrades drops off significantly. Project sizes up to 380 MW have been investigated. Waneta Expansion has not been included as a resource option as there was not enough information available at the time of writing.

5.3.2. Pumped Storage

Pumped storage is used worldwide for energy management, frequency control and provision of reserves.

Conventional pumped hydro uses two reservoirs, separated vertically. During off-peak hours, water is pumped from the lower reservoir to the upper reservoir. When required, the water flow is reversed to generate electricity. Underground pumped storage, using flooded mine shafts or other cavities or the open sea, is also technically possible.

Pumped hydro was first used in Italy and Switzerland in the 1890s. Adjustable speed machines are now being used to improve efficiency. Pumped hydro is available at almost any scale, with discharge times ranging from several hours to a few days. Their efficiency of pumped hydro is now in the 70 per cent to 85 per cent range.

There is over 90 GW of pumped storage in operation worldwide, which is about three per cent of global generation capacity.

BC Hydro explored pumped storage opportunities near B.C.’s main load centres, the Lower Mainland and Vancouver Island, as resource options in the 2004 IEP. The 2001 Vancouver Island Green Energy study investigated Vancouver Island pumped storage options to a limited extent. The resource option database includes options that were considered to have the lowest environmental impact and lowest cost, and to provide a maximum of 500 MW of pumped storage.

Although pumped storage schemes have been explored in the Lower Mainland (e.g., using Harrison Lake or Stave River power plant upper storage), these projects were not included in the 2004 IEP options because information was limited and over 20 years old. These projects require further study in order to be included as future resource options, and may be investigated in 2004 as part of an energy storage study being conducted by BC Hydro.

The financial costs of pumped storage were characterized by estimating capital and operating costs, exclusive of the cost of energy for pumping. The overall cost of capacity and energy from a pumped storage facility would depend on the cost of energy consumed during low-load pumping hours and the price of energy during heavy-load generation hours. BC Hydro would have to model this difference and usage in detail to estimate a unit energy cost. In general, the increased capacity provided by pumped storage is of greater interest.

5.4 Resource Smart

The Resource Smart program, initiated by BC Hydro in 1987, provides additional electricity to the BC Hydro generation system through physical and operational modifications to existing facilities. Economically attractive Resource Smart projects typically have very low or no environmental impact, no air emissions or, in the case of thermal facilities, reduced air impacts. Most projects provide a small amount of additional energy or capacity. Resource Smart involves projects in all parts of the province, contributing to local economic development.

Resource Smart projects may reduce the amount of energy consumed in generating stations or substations, or they may increase electricity production at existing generating stations or water storage reservoirs. Benefits of Resource Smart projects include:

Low Cost: Resource Smart projects are generally economic additions of energy and capacity, particularly since the project is part of an existing, accessible, licensed facility.

High reliability: Resource Smart projects are improvements to existing hydroelectric facilities and may result in replacement of less reliable equipment.

Clean and low environmental impacts: Resource Smart changes and improvements rarely result in unacceptable environmental impacts. For example, a tailrace excavation to reduce tail water heights and increase energy capability would be a carefully controlled activity to minimize impacts on fish.

Licensable: Resource Smart projects are typically licensable because the existing facility has gone through the major approvals and licensing process.

5.4.1. Hydroelectric Opportunities

Potential future Resource Smart projects include:

- Turbine upgrades;
- Tailwater improvements;
- New generating units; and
- Channel improvements.

Significant capacity additions are available at Mica and Revelstoke Generating Stations with the installation of two new units in the existing powerhouses at each facility. Both projects were designed and constructed with these fifth and sixth units in mind.

Over time, numerous Resource Smart projects have been rejected by BC Hydro as infeasible or uneconomic. For example, a second power plant at John Hart Generating Station on Vancouver Island (with a potential dependable capacity of 138 MW) and an additional generation unit at Puntledge Generating Station on Vancouver Island have been omitted from the 2004 resource option database. Both projects would require significant additional water flow to power the turbines, likely resulting in unacceptable streamflow impacts.

The best opportunities, as measured in economic return, size and ease of external permitting and internal approvals, have been completed or are in progress. Generally, these opportunities have been at BC Hydro's larger facilities. The remaining opportunities offer smaller gains and their economic performance is not as good, since they generally exist at the medium-sized, older plants.

In some situations, facilities are reaching the end of their lives, are no longer reliable or have high maintenance costs. In these cases, redevelopment of the project is proposed. BC Hydro is currently considering redevelopment of the Aberfeldie Generating Station and facilities.

5.4.2. Burrard Thermal

The Burrard Thermal Generating Station (Burrard) is a natural gas-fired steam turbine generating station located in the Lower Mainland. The plant comprises six units, which were constructed in the 1960s and 1970s. Burrard's output (net of its own energy requirements) is 913 MW. The 2004 IEP supply reflects a base case in which three units at Burrard are assumed to be available for operation in F2004 to F2006, and all six units available over the remainder of the 20-year planning horizon. Part 2 of the IEP discusses the base case for Burrard.

The Resource Options database presents information on several possible configurations for Burrard, including shutdown, and repowering with combined-cycle gas turbines. The cost estimates for these configurations assume cost savings from re-use of infrastructure at the existing Burrard site. These cost savings have been estimated to be approximately $150 million for the case where the site is fully repowered relative to the alternative of constructing new greenfield combined-cycle gas turbines in the Lower Mainland. Because the study that yielded this estimate was conducted approximately ten years ago, there is uncertainty about the current value.

A committee of members of the provincial legislative assembly is conducting a technical review of Burrard, including the possibility of phasing out the existing operation of the plant. At the time of publication of the 2004 IEP, the government has not announced what actions it will take on the findings of the review. The government's decision on this review could have implications for the existing operation and future options for Burrard.

5.5 Imports

Electricity supply options in B.C. include the possibility of acquiring additional energy from the electricity market. Options available include:

- Non-firm market purchases from outside British Columbia;
- Contracted purchases from outside British Columbia; and

The operation of the total BC Hydro system is optimized in part with economic use of non-firm imports and exports. Treatment of imports and exports in portfolio and system modelling is described in Part 5 of the IEP.

Although not considered as options by in the IEP, there are numerous electricity projects being planned in neighbouring jurisdictions. These projects include electricity generation associated with oil sands extraction in northern Alberta, natural gas-fired generation in the Pacific Northwest, and other developments.

5.6 Downstream Benefits

This section discusses the Canadian Entitlement to Downstream Benefits (DSBs) under the Columbia River Treaty. The province of British Columbia owns the Canadian Entitlement to Downstream Benefits (DSBs) from the Columbia River Treaty. Under an agreement effective April 1, 1999, the province assigned its right, title and interest in the Entitlement to Powerex, which the province receives the market value of this resource.

The DSBs resulted from the construction and operation of three Canadian Columbia River Treaty dams: Duncan dam, Hugh Keenleyside (also called Arrow) dam and Mica dam. These projects regulate river flows, providing downstream flood protection and increasing the generation capability at projects on the U.S. portion of the Columbia River. The Canadian Entitlement to the Downstream Benefits is half of the additional electricity potential in the U.S. projects on the Columbia River as a result of the operation of the Canadian Treaty dams. The DSB entitlement is based on a calculation prepared annually (Treaty Operating Plan Studies) by BC Hydro and the U.S. Entities, which takes into account variations in expected power demand and generation resources in the Pacific Northwest.

Currently, the DSBs are forecast to provide approximately 1,200 MW of dependable capacity. As of 2010, the DSB energy is forecast to be in the order of 480 average MW or 4,200 GWh per year and this amount is expected to decline by about 10 average MW per year.

The Entitlement is a “capacity rich” resource. Because it has 1,200 MW associated with only 4,200 GWh or less, its energy can all be scheduled into HLH. Therefore, the market value of the DSBs is based on HLH prices, which are higher than prices for flat or light load hours (LLH).

The market price of the DSB energy is greater than other market opportunities that BC Hydro would expect to be able to purchase (i.e., HLH price vs. flat or LLH price). However, the capacity associated with the DSBs is available to BC Hydro by requesting that Powerex not export energy at the time the capacity is required on the BC Hydro system. BC Hydro used this flexibility over the most recent winter peak (January 2004). Furthermore, BC Hydro could elect to purchase even more capacity flexibility from Powerex, by requesting a modification of preferred scheduling options to meet BC Hydro’s system needs.

6 Transmission Options

Transmission lines and other transmission upgrade resource options provide information on capacity or energy transfer capability. This transfer capability involves projects that increase capacity on existing lines in an integrated electricity system, or projects to build new lines to get electricity from new supply options to load centres. The British Columbia Transmission Corporation (BCTC) now plans, manages, and operates BC Hydro's transmission system. BCTC participated in establishing the resource options in the IEP by providing information for major transmission upgrades required by various supply portfolios.

The three basic types of transmission reinforcement options are:

- Transmission line options;
- Station and voltage support equipment options; and
- System control options.

6.1. Transmission Lines

The transmission line carries electricity from the generation source (whether a utility or independent power producer) to the load centre. Transmission network capacity (the ability to transmit power over long distances) is limited by:

- The thermal rating of the lines;
- Transient stability; and
- The supply of reactive power for voltage stability.

Deficiencies in transmission system capacity can decrease reliability, increase power losses and increase operating complexity. Adding a transmission line to the existing transmission network will increase the network's limits (thermal, transient and/or voltage stability), while at the same time reducing losses.

Building a new transmission line is a capital-intensive option with a long lead time and impacts on the local environment and communities. As a result, upgrading existing transmission lines, typically with shorter lead times because regulatory requirements are reduced, may be a more achievable option to increase transmission capability.

The capability of the existing network can be increased without a new line by:

- Installing series compensation on the existing transmission lines, reducing the resistance of the line to electrical flow and increasing its power transmission capacity;
- Installing new or larger conductors on existing lines to give them a higher current rating; and
- Installing phase-shifting transformers to optimize the power flow on the existing transmission network.

Many of these options have lower capital costs than building a new line, but they may result in higher system losses and lower system capability. In addition, they make system operations more complex.

6.2. Station and Voltage Support

The power transfer capability of a transmission system may be limited by voltage stability. By providing additional “reactive power” support in the system (measured in VAr, or Volt-Ampere reactive), the transmission system can raise its voltage stability, allowing an increased power transfer.

A number of non-line alternatives can provide additional reactive power, such as static VAr compensators, mechanically switched capacitors, additional series compensation on the existing transmission lines and synchronous condensers. These reactive options have lower capital costs and have less environmental impact compared to new lines, but increase system losses and usually provide lower capability increases.

6.3. System Control

Special protection and control system schemes, also known as remedial action schemes, are sometimes installed to increase the transfer capability of the transmission network. Automatic generation shedding, direct load shedding, direct tripping of remote transmission, and special system stability controls are commonly used. Competitive pressures and opposition to new transmission lines are causing utilities to rely more on alternatives such as protection systems to maintain reliability without reducing system transfer capability.

6.4. Options and Attributes

The IEP focused on three key bottlenecks in the bulk 500 kV transmission system:

- Kelly/Nicola (South Central Interior) to the Lower Mainland;
- Lower Mainland to Vancouver Island; and
- Selkirk Area (Kootenays) to Kelly/Nicola (South Central Interior).

Focusing on the bulk transmission system addresses the need for transmission resources to mitigate regional imbalances in demand and supply. Local reinforcements have shorter lead times, smaller capital costs and less impact on the environment and communities. These reinforcements would be developed as the specific loads and resources and their locations are identified.

A reinforcement in the North Coast region was not included specifically in the 2004 IEP resource options, but may be considered if planning portfolios suggest a need.

There is a wide range of potential reinforcement options for increasing the transmission system capability by relieving these bottlenecks (Table 6.1). Usually one option cannot be traded off against another, since the mix and sequence of options governs their selection for a particular resource portfolio.

Table 6.1. IEP Transmission Options

Reinforcement	Cost ($2003 million)	Capacity Transfer Capability
Kelly Nicola to Lower Mainland		
Kelly Lake to Cheekye 500 kV line (5L46) (Clinton to Squamish)	$249	1000 MW to 2850 MW
Nicola to Meridian 500 kV Line (5L83) (Merritt to Coquitlam)	$249	1750 MW to 2350 MW
Nicola to Ruby Creek 500 kV Line (5L80) (Merritt to 15 km east of Agassiz)	$140	1750 MW to 2350 MW
500 kV Transmission Line for Kelly/Nicola CCGT	Not known depends on location of generation	Adequate for generation capacity
Kelly Lake 500 kV Substation Reconfiguration	See Appendix G	Not applicable
Nicola 500 kV Reconfiguration – Timed with Revelstoke 5	$8	Not applicable
122.5 MVAr Shunt Reactor @ 500 kV Nicola substation	See Appendix G	Not applicable
150 MVAr Shunt Reactor @ 230 kV Ingledow Substation (Surrey)	See Appendix G	Not applicable
250 MVAr Mechanically Switched Capacitor @ 500 kV Nicola Substation	$5	Varies depending on project timing and resource portfolio.
250 MVAr Mechanically Switched Capacitor @ 500 kV Ingledow Substation	See Appendix G	Not applicable
250 MVAr Mechanically Switched Capacitor @ 500 kV Meridian Substation (Port Moody)	See Appendix G	Not applicable
250 MVAr Mechanically Switched Capacitor @ 500 kV Ashton Creek Substation (near Enderby)	$5	Varies depending on project timing and resource portfolio.
Series Capacitors /Interior to Lower Mainland (ILM) Thermal Upgrades	$144	> 425 MW
Lower Mainland – Static VAr Compensators (SVC)	$57	Varies depending on project timing and resource portfolio.

Lower Mainland to Vancouver Island		
Arnott Station to Vancouver Island Terminal Substation 230 kV AC (Delta to Duncan via Galiano and Saltspring Islands)	$309	600 MW to 1200 MW
Arnott Station to Vancouver Island Terminal Substation HVDC Replacement (Upgrade)	$212	540 MW to1080 MW
Vancouver Island		
Upgrade of 230 kV Dunsmuir-Sahtlam line to 500 kV (Qualicum to Duncan)	See Appendix G	1100 MW
Selkirk Region to Kelly Nicola		
5L91/98 Series Compensation	$85	~ 270 MW
Lines 5L71/72 Series Compensation (required to accommodate Mica new unit, #5)	$30	~ 450 MW
Lines 5L76/79 Series Compensation (accommodates Revelstoke Unit #6)	$51	~ 440 MW
Downie Station and Lines	$131	Would integrate Revelstoke Unit 6 and Mica Unit 6 reliably.
122.5 MVAR Shunt Reactor @ 500 kV Selkirk (Castlegar)	See Appendix G	Not applicable
Selkirk Transformer T2- Replacement of 673 MVA with 1200 MVA	See Appendix G	About 400 MW
Selkirk Transformer T3- Replacement of 673 MVA with 1200 MVA	See Appendix G	About 400 MW
Central Interior		
Williston -Tachick 230 kV Transmission line 2L357 (Prince George to Vanderhoof)	See Appendix G	300 MW
Peace River		
Site C – Peace Canyon 2 x 500 kV Transmission line (Hudson's Hope)	See Appendix G	Adequate for Site-C generation.

6.4.1. Vancouver Island Inter-regional Options

Table 6.1 also shows inter-regional options identified for Vancouver Island bulk electricity supply plans:

- 230 kV AC Arnott-to-Vancouver Island Terminal station interconnection. This includes replacement of the two-circuit 138 kV interconnection with two 600 MW, 230 kV submarine cable circuits built in two stages.
- HVDC (High-Voltage Direct Current) Replacement. This includes replacing the existing 312 MW Pole 1 with 540 MW Pole 3 terminal converter stations while using existing submarine cables in the initial stage. The second stage would include replacement of the existing Pole 2 with 540 MW Pole 4 terminal converter stations and new submarine cables.

An option to extend the life of the HVDC system was characterized as an operational measure and not reliable enough to be listed as a firm planning resource.

Several references were made during the hearings on the Vancouver Island Generation Project to intra-regional transmission reinforcement options to integrate additional generation in the central or northern Vancouver Island system, such as the proposed NorskeCanada and Green Island Power IPP projects. If these projects were developed to meet the load on Vancouver Island, it would be necessary to upgrade the existing Dunsmuir-to-Sahtlam 230 kV circuits to 500 kV operation (included in the database), and also to upgrade the transmission north of Dunsmuir. Other intra-regional transmission reinforcement options were not included in the 2004 IEP as resource options, and would likely be studied as part of feasibility or design studies for a specific generation project or group of projects.

7 Results Summary

7.1. Information Summary

The resource option database contains information on a wide variety of projects for which varying levels of detail are available. Many of the detailed studies were done previously by BC Hydro or external consultants, and additional detailed studies may be done in the future. Table 7.1 summarizes the level of information available for each project or resource type.

The resources and projects included in the IEP were not an exhaustive inventory; rather they were based on available information at the time.

Table 7.1. Information Level Summary

Level of Information	Resource Type	Approximate Annual Average [7] GWh
Well Studied[1]	Power Smart 2	4,000
	Resource Smart – Hydro (Planned Efficiency upgrades)	400
	Resource Smart – Hydro (Planned Capacity Increase)	90
	Resource Smart – Hydro (Revels. Capacity increase)	120
	Resource Smart – Thermal (Burrard) [5]	6,400
	Wind (Vancouver Island Rumble Ridge site)	54
	Large Hydro (Peace Site C)	4,800
	Vancouver Island Generation Project	1,900
	Downstream Benefits [8]	1,200
Industry Standards Used and/or Preliminary Studies[2]	Power Smart 3	2,600
	Resource Smart – Hydro (Other Efficiency upgrades)	170
	Resource Smart – Hydro (Mica Capacity increases)	100
	Biomass	1,800
	Wind (sites with monitoring)	1,700
	Natural Gas	8,200
	Coal	8,500
	Oil and Diesel	120
	Large Hydro (Border Dam & Murphy Cr.)	2,900
	Pumped Storage (capacity only)	-
High-Level Estimates[3]	Power Smart 4	2,600
	Small Hydro (< 20 MW)	8,600
	Small Hydro (> 20 MW)	2,700
	Geothermal	1,400
	Large Hydro (Elaho R.)	95
Future Prospects[4]	Power Smart 5	2,200
	Wind (sites with no monitoring)	3,200
	Wave	630
	Tidal	1,500
	Solar (maximum potential) [6]	380
	Fuel Cells	51

Notes:

1. Well Studied – includes the Level of Study categories from the resource option database of Design, Feasibility and projects "In progress."

2. Industry Standard and/or Preliminary Studies – incorporates projects with a site-specific pre-feasibility study that includes a rough resource estimate, and projects that use proven “off-the-shelf” technology.
3. High-Level Estimates – encompasses Pre-feasibility study (desk studies) category used in the database. These projects have been studied to some degree but are not yet at a detailed level of study.
4. Future Prospects – includes projects classified as Conceptual and “not yet proven” technologies.
5. Resource Smart – Thermal (Burrard) is an average of the four Burrard repowering options. The Burrard Generating Station – Immediate Shutdown option would result in a significant annual average energy decrease and has not been included in the average.
6. The Solar approximate average annual energy has been calculated as the sum of the averages of early adopter and maximum potential for both commercial and residential resources.
7. Total approximate annual average GWh has been rounded to the nearest ten.
8. MW available from Downstream Benefits vary from year to year.

7.2. Energy Summary

The results of the resource option characterization show that a wide variety of alternatives are available to BC Hydro, but at varying costs, different levels of dependability and reliability, and diverse environmental and social attributes, risks and uncertainties. Figure 7.1 shows the contribution of each resource type to the total energy potential of the projects included in the database. Figure 7.2 displays the resource categories and the range of unit energy costs estimated for each.

Figure 7.1. Average Annual Energy (GWh) Identified by Resource Type

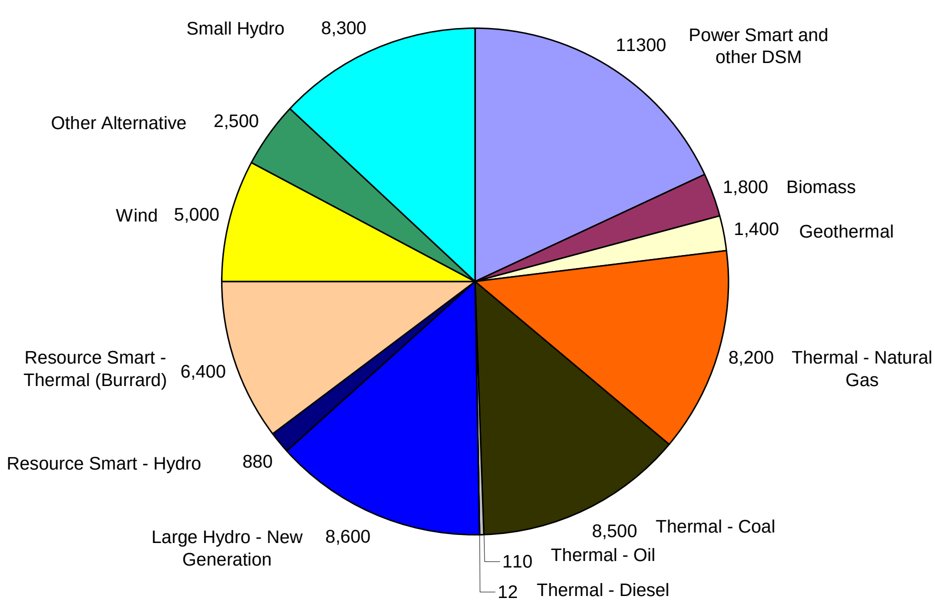


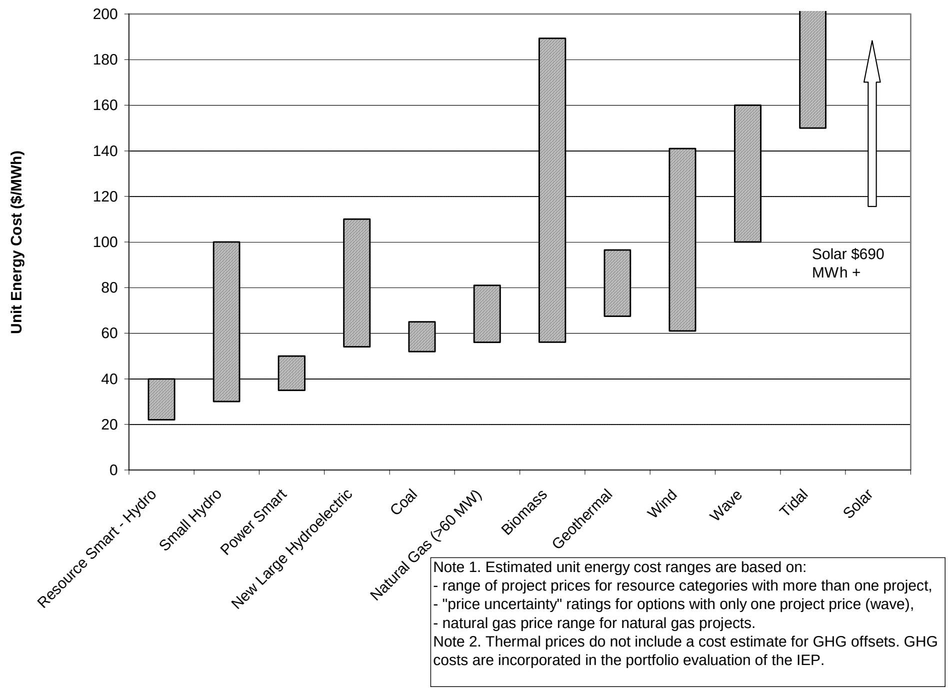
Table 7.2. Resource Option Summary

Resource Type	Annual Average Energy (GWh)	Unit Energy Cost ($/MWh) [1]
Power Smart [2]	11,300	35 – 50
Small Hydro (>20 MW)	2,730	55 – 91
Small Hydro (< 20 MW, <$70/MWh)	2,930	30 – 70
Small Hydro (< 20 MW, $70 to $100/MWh)	2,600	71 – 100
Biomass	1,800	56 – 190
Geothermal	1,400	67 – 97
Wind	5,000	60 – 140 [3]
Wave	630	100
Tidal	1,500	150 – 360
Solar [4]	400	700 – 1,700
Fuel Cells	50	N/A
Thermal – Natural Gas > 59 MW [5, 6]	8,100	56 – 81
Thermal – Coal [6]	8,500	52 – 65
Thermal – Oil [6]	110	130 [9]
Thermal – Diesel Internal Combustion Engine [6]	12	205
Large Hydro	8,600	54 – 110
Resource Smart – Hydroelectric	880	22 - 40
Resource Smart – Thermal (Burrard) [7]	6,400	N/A [8]
Imports [8]	-	-
Reference: BC Hydro Customer-Based Generation Call 2002	-	55

Notes:
Resource option information has been prepared for BC Hydro's electricity planning purposes only. This information should not be relied upon by others for design, financing or development decision-making. Actual technical and financial project information may vary from that shown here.

1. Range of cost estimates based on project information averages, not including price uncertainty.
2. Power Smart unit energy costs are total resource cost estimates that include the cost to BC Hydro (utility cost) and the cost to the customer (customer cost). Power Smart estimates include avoided transmission losses.
3. Small-scale wind projects have an estimated unit energy cost of $500/MWh.
4. Solar energy values represent the estimated maximum potential.
5. Unit Energy Cost estimates for natural gas projects are illustrative and may be revised through specific dispatch rates used in portfolio modelling and an evaluation of fuel price forecasts.
6. The energy assumed from thermal projects is not necessarily limited to the totals shown, but rather reflects multiple units or projects that could be developed for more energy.
7. Resource Smart – Thermal (Burrard) is the average of the repowering options.
8. N/A: Unit energy costs were not available and have not been estimated. Unit energy costs for mobile diesel generating units were not available.
9. Import energy availability costs and modelling assumptions are based on fluctuating spot market availability and prices and are discussed in IEP Part 5.

Figure 7.2. Selected Resource Option Unit Energy Cost Comparison



7.3. Dependable Capacity Summary

A distinguishing characteristic among the resources characterized was their ability to provide dependable capacity when electricity is specifically needed. Table 7.3 summarizes the resources that provide some dependable capacity, and the cost of their installed capacity.

Dependable capacity is an important resource attribute. Many Green and alternative resources provide an intermittent supply because they depend on an intermittent natural resource (e.g., wind, wave, tidal current). Figure 7.3 shows the contribution of each resource to the total dependable capacity options included in the database. It should be noted that the upper limit of thermal fossil fuel generation (typically based on the upper limit of fuel supply) has not been calculated, and thermal generation may be capable of supplying a greater portion of total dependable capacity.

Dependable capacity is an important resource attribute. Many Green and alternative resources provide an intermittent supply because they depend on an intermittent natural resource (e.g., wind, wave, tidal current). Figure 7.3 shows the contribution of each resource to the total dependable capacity options included in the database. It should be noted that the upper limit of thermal fossil fuel generation (typically based on the upper limit of fuel supply) has not been calculated, and thermal generation may be capable of supplying a greater portion of total dependable capacity.

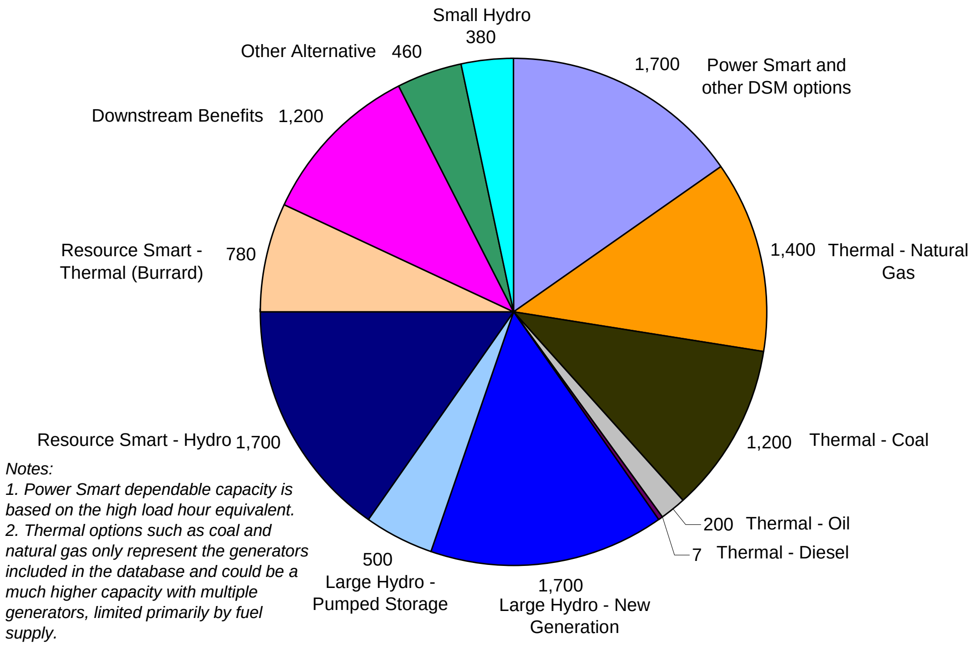
Table 7.3 Dependable Capacity by Resource Type

Resource Type	Installed Capacity (MW)[1]	Installed Capacity Capital Cost (1,000 $/MW)[2]	Dependable Capacity (MW)	Dependable Capacity Capital Cost (1,000 $/MW)[2]
Small Hydro (>20 MW) [3]	750	1,500 – 2,900	210	4,800 – 32,000
Small Hydro (< 20 MW, <$70/MWh) [3]	630	1,100 – 2,000	86	7,800 – 15,000
Small Hydro (< 20MW, $70 to $100/MWh) [3]	610	2,200 – 2,600	89	13,000 – 25,000
Biomass	220	1,500 – 6,300	220	1,500 – 6,300
Geothermal	190	3,000 – 4,200	190	3,000 – 4,200
Wind [4]	1,610	1,850 – 2,700	0	–
Wave	200	700 – 800	10	14,000 – 16,000
Tidal	840	1,400 – 3,400	42	28,000 – 66,000
Solar	440	3,000 – 11,000	0	–
Fuel Cell	6	880 – 3,500	6	–
Thermal – Natural Gas [5]	1,440	440 – 1,800	1,360	500 – 2,000
Thermal – Coal [5]	1,300	1,100 – 1,700	1,220	1,200 – 1,900
Thermal – Oil [5]	200	220 - 1,000	200	220 - 1,000
Thermal – Diesel [5]	7	570	6.7	600
Large Hydro – New Generation	1,650	2,400 – 4,700	1,650	2,400 – 4,700
Large Hydro – Pumped Storage	500	1,200	500	1,200
Resource Smart – Hydro	2,000	200 – 2,200	1,800	220 – 300
Resource Smart – Burrard Average of Repower Options	800	700 – 1100	780	780 – 1,100
Power Smart [6]	Not Calculated	–	1,655	180 – 1,100
Downstream Benefits [7]	1,200	–	1,200	–

Notes:

1. Costs per MW represent a division of capital costs by dependable or installed MW, and have not been levelized.
2. Values are rounded to two significant figures in most cases to represent the level of detail in assumptions and information. Energy estimates have been rounded to reflect the preliminary nature of the data.
3. Small hydro project bundles with zero or very low dependable capacity are $280,000,000/MW dependable capacity. These high values have not been shown for reader clarity.
4. Small-scale wind projects have an estimated cost of $5,100 per installed kW.
5. The installed capacity for thermal projects is not necessarily limited to the totals shown, but rather reflects multiple units or projects that could be developed for greater capacity.
6. Power Smart dependable capacities are an “equivalent” dependable capacity for savings during heavy load winter peak hours.
7. DSBs = Downstream Benefits from the Columbia River Treaty.

Figure 7.3. Dependable Capacity (MW) Identified by Resource Type



7.4. Regional Distribution of Resources

Projects and resources in the database were either site-specific, region-specific or applicable to the entire province. The non-site-specific projects include greenfield diesel and oil, where the project could be located in any region. Power Smart programs are characterized as non-regional-specific and provide province-wide energy savings, although the savings from Power Smart will be different for each region depending on population, load characteristics, and regional economy and industry. Figure 7.4 shows the regional distribution of the resources identified in the database, based on energy capability.

Figure 7.4. Average Annual Energy Potential By Region (% total GWh)

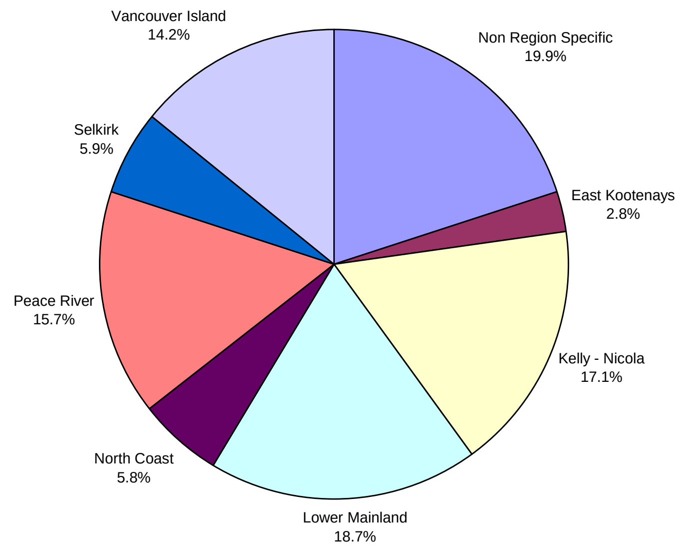
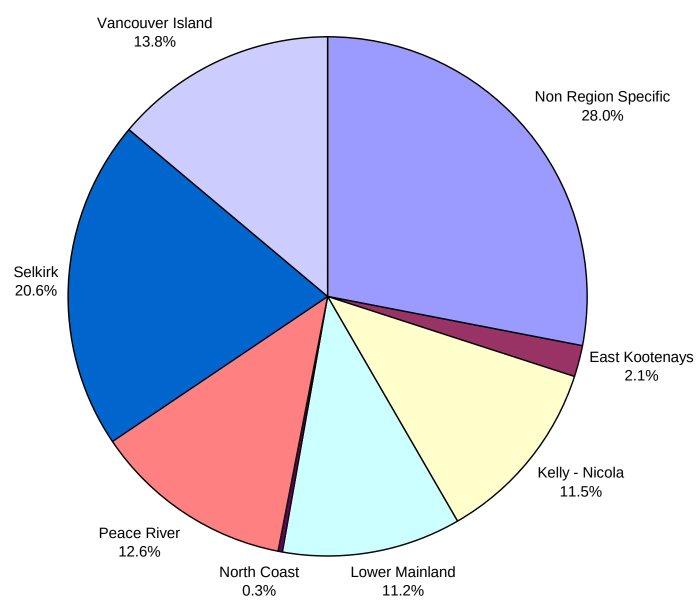


Figure 7.5 shows the dependable capacity as distributed throughout each region, with some of the dependable capacity being non-region-specific (generic non-site-specific projects and province-wide initiatives).

Figure 7.5. Dependable Capacity of Resources by Region (% total MW)



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