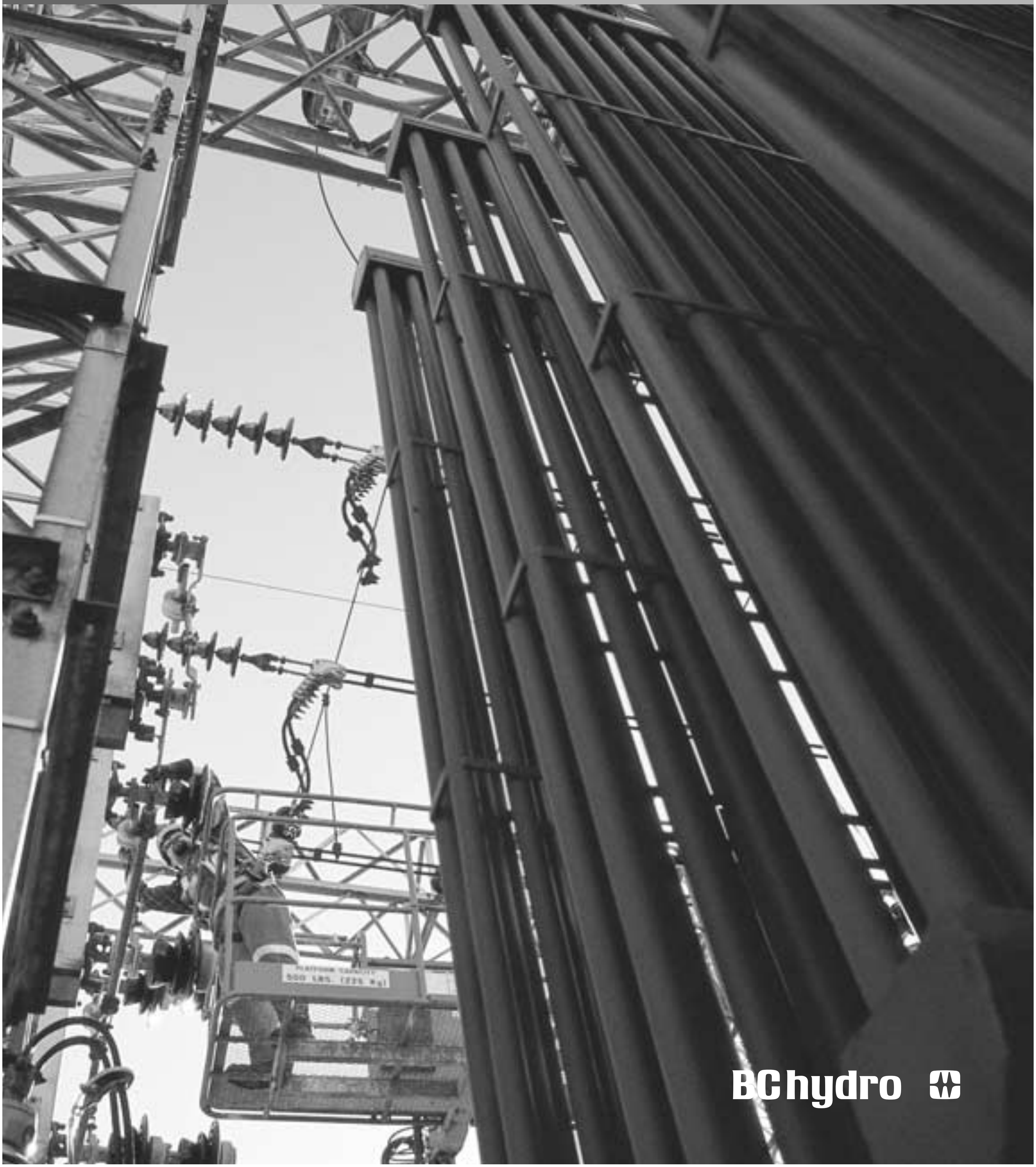
# Second Quarter Report

For the six months ended September 30, 2002




BC hydro

## INDEX

## 1. OVERVIEW

### KEY HIGHLIGHTS

### Financial

- Consolidated net income of $141 million for the six months ended September 30, 2002, was $23 million lower than for the same period in the previous year. A decrease in electricity trade margins, due to lower market prices, was the primary reason for the unfavourable variance. The decrease in trading margins was partly offset by the positive impact of higher water inflows into BC Hydro's reservoirs and to a decrease in finance charges.
- Net income of $101 million for the second quarter of this year was $11 million higher than for the same period last year. An increase in domestic revenues and a decrease in finance charges were the primary reasons for the increase in income. The impact of improved water inflow conditions helped offset the decrease in electricity trade margins.
- BC Hydro's forecast net income for fiscal 2003 is approximately $350 million. Based on this forecast, a transfer of approximately $65 million will be required from the Rate Stabilization Account (RSA) in order for BC Hydro to earn its allowed return on equity. This will leave approximately $22 million in the RSA at the end of the year. BC Hydro is subject to various risks and uncertainties that can cause significant volatility in the earnings. Factors such as the level of water inflows into its reservoirs, market prices for electricity and natural gas, interest rates, foreign exchange rates, weather and regulatory and government policies influence both the operation of the BC Hydro system and its earnings. As a result of these risks and uncertainties, BC Hydro's net income for fiscal 2003 could range from $285 million to $430 million under various plausible scenarios.

### Performance Plan

- BC Hydro's second quarter performance was better than expected. Eight out of the nine measures reported on either met (5) or exceeded (3) their quarterly targets.
- BC Hydro exceeded its quarterly financial goals. Net income was significantly better than target mainly as a result of higher residential revenues, due to weather induced demand, and industrial and commercial revenues, owing to an increased customer base, and higher industrial revenues, because of an increase in production in the pulp and paper, chemical and mining sectors.
- BC Hydro exceeded its quarterly safety goal by achieving more than its targeted reduction in the combination of medical aid injuries and disabling injuries.
- BC Hydro exceeded its quarterly environmental goal. Environmental incidents during this period were significantly lower than forecast.
- BC Hydro did not meet its quarterly reliability goal. The average number of hours per interruption was worse than expected, mainly due to three major weather events. Although most of these events took place in the last fiscal year, they impact the current results because reliability is measured over a rolling 12-month period. For the current results, this period was October 1, 2001 to September 30, 2002.

### Domestic Supply and Demand

- Year-to-date total energy sales were 424 GW.h or 1.9 per cent higher compared to the same period last year: Industrial sales were 121 GW.h lower; General sales were 266 GW.h higher; Residential sales were 294 GW.h higher; and Other sales were 27 GW.h lower.

- BC Hydro is a winter peaking utility because of residential electric space heating and peak demand is much lower in non-winter months. The domestic integrated system peak was at 6662 MW in September. This compares to a peak demand of 6452 MW in September 2001.
- The per cent of normal system energy for the 2002 water year (October 1, 2001 to September 30, 2002) was 108 per cent. System energy is the approximate value of the annual inflow volume. Peace River basin inflows for the February to September period were 24 per cent above average due to an above average winter snowpack as well as above average spring/ summer rainfall. These very high runoff conditions resulted in spills at our G.M. Shrum and Peace Canyon generating stations during the month of July. Columbia River streamflows were near average for the February–September runoff period; Kootenay River basin streamflows were slightly above average. Bridge River System streamflows were near average for the runoff period and reservoir levels are near normal for this time of year. Most of the Lower Mainland reservoirs had near normal inflows during the runoff period, with the exception of the Alouette basin which had above average water supply during February–September. On Vancouver Island, the Campbell River, Comox and Elsie reservoirs had very low water supply conditions due to a very dry spring and summer. Rainfall throughout southern B.C. during the late summer and early autumn period has been well below normal. As a result, Coastal project reservoirs are now generally below normal.

## Lines of Business

- By the end of the second quarter, one green IPP contract was executed and approximately 153 GW·h/yr was added to our total green energy purchased. The target for fiscal 2003 is five to ten new contracts, equalling 350 GW·h/yr in green energy. BC Hydro will issue another call for green energy in October 2002 for up to 800 GW·h/yr.
- Under its Customer-Based Generation (CBG) initiative, BC Hydro is seeking ten to 20-year agreements to supply new, competitively priced electricity totalling 800 GW·h/yr from customer-based generation. In response to a Request for Qualifications, BC Hydro received 38 proposals from customers from all sectors across the province. On September 6, a shortlist of 22 proposals was announced and these projects were invited to participate in the Call for Tender process. The standardized Electricity Purchase Agreement has been posted on BC Hydro's external Web site and a bidders workshop is set for November 4.
- The provincial Environmental Assessment Office (EAO) extended the timeline for review of the Vancouver Island Generation Project (VIGP) by 15 days to allow the maximum time for public comment. A further Ministerial extension was requested and granted to complete public consultation and accommodate First Nations consultation. The scheduled in-service date is still November 2004, but steps are being taken to limit commitments going forward until the Georgia Strait Crossing (GSX) Project regulatory approval becomes firm. The overall capital cost for the project has been re-estimated at $370 million, including an allowance for a fall 2005 in-service date should GSX be delayed.
- BC Hydro and the Williams Gas Pipeline Company (WGP) are jointly sponsoring the Georgia Strait Crossing (GSX) Project, which will provide firm natural gas transportation to Vancouver Island to supply the existing Island Cogeneration Project and the Vancouver Island Generation Project. The results of the recently completed detailed WGP and BC Hydro cost review shows a not-to-exceed cost of $340 million, based on 90 per cent probability of non-exceedance. BC Hydro's share of the cost is expected to be $171 million. These increases— which are still being reviewed and have not been approved by BC Hydro—are primarily related to a revised estimate for the original October 2004 in-service

date (including increased costs for scope changes, increased regulatory/environmental requirements and increased First Nations issues) and a potential delay in the in-service date to October 2005 due to delays in the hearing process. Regulatory applications for the project were filed with the National Energy Board (NEB) in Canada and the Federal Energy Regulatory Commission (FERC) in the U.S. in April 2001. The FERC process is complete and a certificate for the U.S. portion of the project was issued on September 20, 2002.

- In BC Hydro's Request for Expression of Interest (RFEI) process, BC Hydro and Accenture entered into a memorandum of understanding in July to establish a new entity and develop a new service agreement with BC Hydro. The new entity will assume Hydro's Customer Services, Information Technology Services, Network Computing Services, Human Resources Services, Financial Systems, Purchasing, Disbursement Services, Property Services, and Business and Office Services. The Materials Management Business Unit (MMBU) was initially proposed for inclusion with the other Shared Services units, but has now been removed from the RFEI. The other portion of the RFEI—Fleet Services—has been put on hold for the time being as it has not been possible to establish a memorandum of understanding with either of the two finalists.
- Due to the removal on July 1, 2002, of the BC Gas accounts from our Customer Information System, the second quarter was a transition period for both BC Hydro and BC Gas customers. During this period our call centre received and answered more than 14 000 calls regarding the conversion.
- Power Smart program results include savings of 314 GW·h towards this year's cumulative target of 360 GW·h of annual energy savings; of the 314 GW·h total, 295 GW·h came from business customers and 19 GW·h from residential customers.

## MANAGEMENT DISCUSSION AND ANALYSIS

The Management Discussion and Analysis reports on BC Hydro's consolidated results and financial position. This discussion should be read in conjunction with the Management Discussion and Analysis presented in the 2002 Annual Report of BC Hydro and the consolidated financial statements of BC Hydro for the six months ended September 30, 2002 and 2001. This report contains forward–looking statements, including statements regarding the business and anticipated financial performance of BC Hydro. These statements are subject to a number of risks and uncertainties that may cause actual results to differ materially from those contemplated in the forward–looking statements.

### Consolidated Results of Operations

Net income of $141 million for the six months ended September 30, 2002, was $23 million lower than for the same period in the previous year. A decrease in electricity trade margins, due primarily to the substantial decline in market prices experienced since June 2001, more than offset the positive impact of improved water inflow conditions and a reduction in finance charges.

Net income of $101 million for the second quarter of this year was $11 million higher than for the same period in the previous year. An increase in domestic revenues and a decrease in finance charges were the primary reasons for the increase in income. The impact of improved water inflow conditions also helped offset the decrease in electricity trade margins.

#### Domestic Revenues

Total domestic revenues of $1,125 million for the six months ended September 30, 2002, were similar to the prior year. The increase in residential revenues due largely to the cooler weather experienced during the first quarter of this fiscal year was more than offset by the decrease in miscellaneous revenues during the first half of this year. Miscellaneous revenues declined due primarily to a decrease in ancillary service revenues as a result of lower market prices for products such as energy loss compensation for transmission. Revenues from light industrial and commercial customers increased during the second quarter of this fiscal year mainly due to customer growth as approximately 1600 of those customers have been added to the system over the last 12 months. Revenues from large industrial customers also increased during the second quarter of this fiscal year. This increase was primarily due to the expiry of special programs in prior years that offered customers reduced rates under various programs initiated by either BC Hydro or the Provincial Government.

#### Electricity Trade Revenues

BC Hydro's electricity system is interconnected with systems in Alberta and the western United States. This interconnection facilitates sales and purchases of electricity outside British Columbia. Electricity trade activities are carried out by Powerex, a wholly owned subsidiary of BC Hydro. While engaged in electricity trade, BC Hydro ensures its ability to meet its domestic supply requirements is not put under undue risk as a result of these transactions. Electricity trade activities help BC Hydro balance its system by being able to import energy to meet domestic demand when there is a supply shortage in the system due to such factors as low water inflows. Exports are made only after ensuring domestic demand requirements can be met.

Electricity trade revenues for the six months ended September 30, 2002, were $1,015 million, a significant decrease of $2,092 million from the same period last year. The decrease was primarily due to a reduction in average sale prices which fell by 79 per cent from $278/MW·h last year to $59/MW·h this year. Market prices have declined to more traditional levels since June 2001. A 55 per cent increase in sales volumes from 11 194 GW·h in the prior year to 17 320 GW·h this year partly offset the decrease in sale prices. The increase in sales volumes is largely due to greater market opportunities for buy/resell transactions.

Powerex sales and purchases during the first half of the year were as follows:

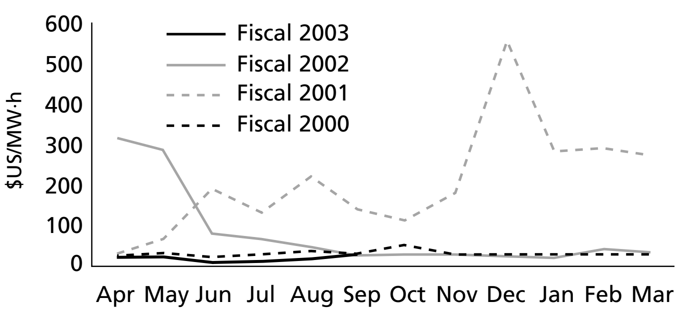
| | (in millions) | | Volumes (in GW·h) | | Average Prices ($MW·h) | |
|---|---|---|---|---|---|---|
| **1st Quarter (April-June)** | **2002** | **2001** | **2002** | **2001** | **2002** | **2001** |
| Sales | $358 | $1,860 | 6,995 | 4,940 | $51 | $377 |
| Purchases[1] | 342 | 1,608 | 9,614 | 7,665 | 36 | 210 |
| Net Import | | | (2,619) | (2,725) | | |
| **2nd Quarter (July – September)** | | | | | | |
| Sales | $657 | $1,247 | 10,325 | 6,254 | $64 | $199 |
| Purchases[1] | 496 | 1,062 | 9,348 | 8,087 | 53 | 131 |
| Net Export (Import) | | | 977 | (1,833) | | |
| **Total** | | | | | | |
| Sales | $1,015 | $3,107 | 17,320 | 11,194 | $59 | $278 |
| Purchases[1] | 838 | 2,670 | 18,962 | 15,752 | 44 | 170 |
| Net Export (Import) | | | (1,642) | (4,558) | | |

[1] These figures reflect energy purchases only and do not include any other component of energy costs such as transmission costs.

BC Hydro did not require any imports to meet its domestic load requirements for the six months ended September 30, 2002. The 1642 GW·h of net imports purchased during the first half of the year will be used for future resale in the electricity trade market. The cost of these purchases has been expensed in the period of purchase for GAAP reporting purposes. BC Hydro was a net exporter of 977 GW·h in the second quarter.

The following graph compares the electricity market prices over the last few years. Market prices at the mid-Columbia multi–lateral trading hub in central Washington state are shown as they are indicative of prices in the Pacific Northwest.

MID-COLUMBIA FLAT INDEX




Electricity trade average sale prices were significantly higher than the market prices in the second quarter of last year largely because Powerex sold forward at higher prices.

### Expenses

Energy costs of $1,228 million for the six months ended September 30, 2002, decreased by $2,020 million from the same period last year. This decrease reflects the decrease in the price of energy purchases, used primarily for future resale in the electricity trade market, and the positive impact of improved water inflow conditions.

Energy purchase prices averaged $44/MW·h for the first half of this year compared to $170/MW·h for the same period last year, a 74 per cent decrease. A decrease in electricity trade transmission costs due to lower market prices also contributed to the decrease in energy costs. An increase in purchases used for buy/resell transactions in the electricity trade market partly offset the impact of the decrease in purchase prices.

Water inflows into BC Hydro's reservoirs increased by 25 per cent over the prior year, allowing for an increase in low-cost hydro generation of approximately 5000 GW·h and the replenishment of reservoir levels. The availability of low-cost hydro generation has a significant impact on energy costs as the variable cost of hydro-generation is substantially less than the cost of electricity purchases or the cost of thermal generation. The combined storage in BC Hydro reservoirs at September 30, 2002 was 109 per cent of average with the Williston Reservoir on the Peace River system at 111 per cent of average and the Kinbasket Reservoir on the Columbia river system at 106 per cent of average. This compares to the combined storage at September 30, 2001 of 97 per cent of average with the Williston Reservoir at 109 per cent of average and the Kinbasket Reservoir at 73 per cent of average. By October 31, 2002, the reservoir levels had declined somewhat to 109 per cent of average at Williston and 99 per cent of average at Kinbasket.

Operations, maintenance and administration (OMA) expenses of $252 million for the six months ended September 30, 2002, decreased by $11 million from the same period last year. This decrease was largely due to a decrease in emergency maintenance costs caused by a failed unit at the Burrard Generating Station in the prior year, timing differences in spending on various programs and to targeted cost reductions. OMA expenses increased by $9 million in the second quarter of this year compared to the same period in the previous year due largely to an increase in employee future benefit costs based on a July 2002 actuarial valuation of BC Hydro's pension liability which reflected increased obligations due to employees retiring earlier and living longer. A decline in the value of the pension fund assets due to the dramatic decline in the stock markets also contributed to the increase in OMA costs. Legal and other associated costs increased by $5 million from the same period last year due to a number of lawsuits, investigations and regulatory proceedings arising from claims related to the electricity wholesale market in California in 2000 and 2001. BC Hydro, along with Powerex and other power companies, has been added as defendants by cross-complaint (i.e. by a defendant) in these lawsuits. BC Hydro continues to believe the terms of Powerex's sales in California were just and reasonable and there was no illegal or improper conduct by Powerex. Powerex intends to vigorously defend its position that it has always transacted in California in accordance with the rules and approved tariffs of the California markets.

### Taxes

Taxes, which are comprised of school taxes, grants in lieu of taxes and the corporation capital tax, decreased by $13 million from the same period last year. This decrease was primarily due to lower corporation capital taxes as a result of a reduction in the corporation capital tax rate in September 2001.

### Depreciation and amortization

Depreciation and amortization charges of $201 million for the six months ended September 30, 2002 increased by $13 million from the same period last year. This increase was primarily due to more assets in service.

### Finance Charges

Finance charges of $244 million decreased by $39 million from the same period last year primarily due to lower short–term interest rates. Interest rates on Canadian variable rate debt declined by 44 per cent to an average of 2.5 per cent for the first six months of this year compared to 4.4 per cent for the same period in the prior year.

## Investing Activities

Capital expenditures, including demand–side management programs, for the six months ended September 30, 2002 amounted to $357 million compared with $224 million for the same period last year.

| (millions of dollars) | 2002 | 2001 | Change Increase (Decrease) |
|---|---|---|---|
| Generation replacements and expansion | $116 | $49 | $67 |
| Transmission lines and substations replacements and expansion | 79 | 34 | 45 |
| Distribution improvements and expansion | 78 | 72 | 6 |
| General–computers, vehicles, etc. | 65 | 68 | (3) |
| Power Smart (Demand–side management) | 19 | 1 | 18 |
| Total | $357 | $224 | $133 |

Sustaining capital expenditures on existing assets amounted to approximately $160 million while expenditures for growth totaled approximately $197 million for the six months ended September 30, 2002.

The increase in generation related expenditures was primarily due to expenditures for the Vancouver Island Generation Project, a new high–efficiency natural gas–fired electricity generation facility to be built at Duke Point near Nanaimo. Expenditures for the six months ended September 30, 2002 totalled approximately $39 million and related to the payments towards the purchase of a gas turbine and steam turbine. The Seven Mile Unit 4 project which involves the design, supply, and installation of a fourth generating unit at BC Hydro's Seven Mile dam and powerhouse on the Pend d'Oreille River near Trail also contributed to the increase in generation expenditures. Expenditures for the six months ended September 30, 2002 totalled approximately $24 million and related to the installation of the hydraulic turbine, generator and related equipment necessary for generation by April 2003.

Expenditures for transmission line replacement and expansion include costs for the Lower Mainland and Vancouver Island South Microwave System Replacement project. The Lower Mainland and Vancouver Island South microwave system is the core of the microwave network and links with the Peace and Columbia power systems. The current equipment consisting of radios, multiplex equipment, batteries and chargers was deteriorating due to age and was becoming increasingly unreliable. The expenditures for the six months ended September 30, 2002 totalled approximately $9 million and related to the purchase and installation of fibre optic cables and also the purchase of digital microwave radios ready to be installed. The Pingston Creek IPP Interconnection project which involves the construction of a new 69 kilovolt (kV) transmission line from Shelter Bay to the Illecillewaet substation also contributed to the increase in transmission line replacement and expansion expenditures. Expenditures for the six months ended September 30, 2002 totalled approximately $7 million and related to the installation of a 230/66 kV transformer at Illecillewaet, the purchase of transmission line material and construction of the overhead line from Walter Hardman to Pingston Generating Station.

BC Hydro's Power Smart energy efficiency program expenditures for the six months ended September 30, 2002 totalled approximately $19 million. Current year activities emphasize incentive–based programs for business customers throughout the Province and residential customers on Vancouver Island.

## Financing Activities

During the six months ended September 30, 2002, BC Hydro issued three Canadian and two U.S. bonds totalling $1,007 million. The proceeds from these issues were primarily used to redeem US bonds totalling $375 million and to fund capital and operating activities. BC Hydro also took advantage of low interest rates to pre–fund some capital expenditures.

## Segmented Results

Consistent with industry trends and best practices, BC Hydro management made a decision to move to a "Lines of Business" structure within the company as the best way to become more competitive, focus resources on distinct customer groups and more effectively meet those customers' needs. Starting this fiscal year, Generation, Transmission and Distribution Lines of Business (LOB's) have been created along with two service groups – Field Services and Engineering Services. Together with the existing Corporate Operations, Shared Services and subsidiaries including Powerex, the company began operating this way as of April 01, 2002.

The Generation, Transmission and Distribution LOB's have been created as profit centres, while the Service Organizations have been created as cost recovery centres. The Service Organizations will be transitioned to profit centres in the future. The costs of the corporate groups are allocated to the LOB's on a reasonable basis.

The main components of the LOB business model for fiscal 2003 include:

### External Revenues

- All domestic retail energy sales, including sales to residential, commercial and industrial customers, are recorded in Distribution. Wholesale energy sales are recorded in Generation.
- Electricity trade sales are recorded in Powerex, BC Hydro's wholly owned power marketing subsidiary.
- Third party wheeling revenues are recorded in Transmission.
- External revenues for BC Hydro's other subsidiaries (including Westech and Powertech) are recorded in Other.

### Inter–segment revenues

- Transmission provides point–to–point and network transmission to Generation and Distribution respectively and charges based on the tariff rates approved by the British Columbia Utilities Commission. As Transmission has open access to its transmission system, third parties are charged the same tariff rates for use of the system.
- Generation provides Distribution with electricity needed to meet Distribution's load requirements and charges based on a negotiated transfer price.
- Generation and Powerex also have a transfer pricing mechanism to charge for sale and purchase transactions between the two units.

For more information on the LOB's and Service Groups, please refer to page 35 to 53.

The transfer pricing methodologies and business model used to determine the revenues and costs of the LOB's are under review this year. The results may be prepared on a different basis in the future depending on factors such as the final outcome of the Provincial Government's Energy Policy.

The following are the segmented results (in $ millions) as of September 30, 2002. As this is the first year of operating under this "Lines of Business" structure, there is no comparative information for the prior year.

### Six months ended September 30, 2002

(millions of dollars)

| | Distribution | Transmission | Generation | Powerex | Other | Consolidation Adjustments/ Eliminations | Total |
|---|---|---|---|---|---|---|---|
| External revenues | 1,081 | 5 | 23 | 1,029 | 25[3] | (23)[3] | 2,140 |
| Inter-segment revenues | – | 392 | 584 | 30 | 283 | (1,289) | – |
| Net income (loss) | (2) | 145 | 45 | 108 | (84) | (71)[3] | 141 |
| Total assets | 2,973 | 3,127 | 5,131 | 1,403[1] | 687[2] | (1,260) | 12,061 |

### Three months ended September 30, 2002

(millions of dollars)

| | Distribution | Transmission | Generation | Powerex | Other | Consolidation Adjustments/ Eliminations | Total |
|---|---|---|---|---|---|---|---|
| External revenues | 533 | 3 | 11 | 671 | 9 | (16)[3] | 1,209 |
| Inter-segment revenues | – | 201 | 284 | 5 | 139 | (629) | – |
| Net income (loss) | (4) | 77 | 11 | 58 | (43) | 23 | 101 |

1 Primarily consists of inter–segment receivables of $1,045 million.

2 Mainly consists of capital assets such as office buildings, vehicles, computer equipment and deferred Demand Side Management Programs.

3 These adjustments mainly relate to the difference between BC Hydro's Management reporting, used for risk management and performance measurement purposes, and GAAP (Generally Accepted Accounting Principles). For Management reporting purposes, energy purchases bought for future resale are inventoried in a Trade Account and expensed when the energy is sold. The balance in the Trade Account is also marked to market at the end of each month and a gain or loss recorded. For GAAP reporting purposes, energy purchases bought for future resale are expensed in the period of purchase.

4 Includes Engineering Services, Field Services and Shared Services Organizations and Corporate costs. The Service Organizations charge the cost of their services to the Lines of Business and Powerex.

## Business Risks/Uncertainties

BC Hydro is subject to various risks and uncertainties that cause significant volatility in its earnings. Factors such as the level of water inflows into its reservoirs, market prices for electricity and natural gas, interest rates, foreign exchange rates, weather and regulatory and government policies influence both the operation of the BC Hydro system and its earnings. While these risks cannot be eliminated, as they are largely non–controllable, some may be mitigated to a certain degree.

## Future Outlook

BC Hydro's net income for this fiscal year is expected to be $350 million before any transfers to/from the Rate Stabilization Account. This is the same as forecast in BC Hydro's Service Plan of January 2002. BC Hydro's income can fluctuate significantly due largely to non–controllable factors such as the market price of energy, weather, interest rates, and water inflows. The range of income under plausible scenarios is estimated to be between $285 million and $430 million.

## Basis of Presentation

The accounting policies and methods of application used in the preparation of these interim consolidated financial statements are consistent with the accounting policies used in the Company's year–end audited consolidated financial statements of March 31, 2002, except for the method for amortizing gains and losses arising from the translation of long–term foreign currency denominated monetary items. These consolidated financial statements do not include all disclosures required for annual financial statements, and therefore these statements should be read in conjunction with the consolidated financial statements for the year ended March 31, 2002, as set out in the 2002 Annual Report.

On July 11, 2002, the British Columbia Utilities Commission approved, under Order Number G–47–02, the continued deferral and amortization of foreign exchange gains and losses on the translation of foreign denominated long-term monetary items, using the straight-line pooled method of amortization, for the fiscal year beginning April 1, 2002 and future periods. Under the straight–line pooled method, foreign exchange gains and losses are amortized based on the weighted average remaining term to maturity of foreign denominated monetary items. The amortization method used in prior years was a reverse sum–of–years methodology, with straight–line amortization in the last four years. The change in methodology increased net income by approximately $5 million for the six months ended September 30, 2002.

## Legal Contingency

A discussion of claims against Powerex is included with the notes to the March 31, 2002 financial statements. Since this date, BC Hydro and Powerex, along with various other energy providers, have been added as defendants by cross-complaints (i.e. by a defendant) in the California electricity consumer class action lawsuits. Those suits allege that the California wholesale markets were unlawfully manipulated and that the energy prices were excessive. On September 19, 2002, BC Hydro applied to the Federal Court in California to have the case against BC Hydro dismissed on the basis of sovereign immunity. A decision on this application is still outstanding.

In April 2002, the California Attorney General commenced an action in the California Superior Court against Powerex seeking statutory penalties for violation of the California *Business and Profession Code*, which establishes certain 'unfair business practices'. (Some 12 similar actions were brought against other energy sellers.) The action alleged that Powerex sold electricity into the

California market during the period from late 2000 to 2001 in violation of the *Federal Power Act* (FPA), such alleged violations of federal law also constituting alleged violations of the California Code. The violations of the FPA alleged were i) failing to file rates and charges (i.e. Powerex's market-based sales data) with the Federal Energy Regulatory Commission (FERC) and ii) charging rates that were "unjust and unreasonable". In August 2002, the action was withdrawn against Powerex only (not the other energy sellers) by the California Attorney General on a "without prejudice" basis. It could therefore be refiled at any time.

BC Hydro continues to believe the terms of Powerex's sales in California were just and reasonable and do not reflect any alleged market manipulation. BC Hydro and Powerex continue to defend itself vigorously in the court proceedings. Due to ongoing developments in regulatory and legal proceedings, BC Hydro cannot reliably predict the outcome of the various claims against both BC Hydro and Powerex.

## CONSOLIDATED STATEMENT OF OPERATIONS *(UNAUDITED)*

| *for the three months ended September 30 (in millions)* | **2002** | 2001 | | |
|---|---|---|---|---|
| *for the six Months ended September 30 (in millions)* | | | **2002** | 2001 |
| **Revenues** | | | | |
| Residential | **$ 176** | $ 175 | **$ 381** | $372 |
| Light industrial and commercial | **217** | 211 | **430** | 423 |
| Large industrial | **129** | 120 | **251** | 249 |
| Other energy sales | **17** | 18 | **35** | 37 |
| Miscellaneous | **13** | 23 | **28** | 45 |
| | **552** | 547 | **1,125** | 1,126 |
| Electricity trade | **657** | 1,247 | **1,015** | 3,107 |
| | **$1,209** | $1,794 | **2,140** | 4,233 |
| **Expenses** | | | | |
| Energy costs | **712** | 1,304 | **1,228** | 3,248 |
| Operations and administration | **72** | N/A | **134** | N/A |
| Maintenance | **60** | N/A | **118** | N/A |
| Total OMA | **132** | 123 | **252** | 263 |
| Taxes | **37** | 43 | 74 | 87 |
| Depreciation and amortization | **99** | 94 | **201** | 188 |
| | $ **980** | $1,564 | **$1,755** | $3,786 |
| **Income before Finance Charges** | **229** | 230 | **385** | 447 |
| Finance charges | **128** | 140 | **244** | 283 |
| **Net Income** | **$ 101** | $ 90 | **$ 141** | $ 164 |

## CONSOLIDATED STATEMENT OF RETAINED EARNINGS *(UNAUDITED)*

| *for the six Months ended September 30 (in millions)* | **2002** | 2001 |
|---|---|---|
| Retained earnings, beginning of year | **$1,529** | $1,459 |
| Net income | **141** | 164 |
| Payment to the Province | **(110)** | (133) |
| | **$1,560** | $1,490 |

## CONSOLIDATED BALANCE SHEET *(UNAUDITED)*

| (in millions) | ***as at Sep 30*** **2002** | *As at Mar 31* 2002 |
|---|---|---|
| **ASSETS** | | |
| **Capital Assets** | | |
| Capital assets in service | **$14,788** | $14,608 |
| Less accumulated depreciation | **5,724** | 5,557 |
| | **9,064** | 9,051 |
| Unfinished construction | **580** | 459 |
| | **9,644** | 9,510 |
| **Current Assets** | | |
| Temporary investments | **123** | 17 |
| Accounts receivable and accrued revenue | **309** | 409 |
| Materials and supplies | **90** | 88 |
| Prepaid expenses | **125** | 111 |
| Unrealized gains on mark-to-market transactions | **9** | 19 |
| | **656** | 644 |
| **Other Assets and Deferred Charges** | | |
| Sinking funds | **1,075** | 1,073 |
| Demand-side management programs | **109** | 103 |
| Deferred debt costs | **526** | 587 |
| Foreign currency contracts | **31** | 32 |
| Loan receivable | **20** | 17 |
| | **1,761** | 1,812 |
| | **$12,061** | $11,966 |
| **LIABILITIES AND EQUITY** | | |
| **Long-Term Debt** | | |
| Long-term debt net of sinking funds | **$7,392** | $6,906 |
| Sinking funds presented as assets | **1,075** | 1,073 |
| | **8,467** | 7,979 |
| **Foreign Currency Contracts** | **7** | 16 |
| **Current Liabilities** | | |
| Accounts payable and accrued liabilities | **501** | 708 |
| Accrued interest | **116** | 107 |
| Accrued Payment to the Province | **110** | 333 |
| Unrealized losses on mark-to-market transactions | **9** | 17 |
| | **736** | 1,165 |
| **Deferred Credits and Other Liabilities** | | |
| Provision for future removal and site restoration costs | **164** | 159 |
| Deferred revenue | **234** | 238 |
| Rate stabilization account | **87** | 87 |
| Contributions arising from the Columbia River Treaty | **207** | 212 |
| Contributions in aid of construction | **599** | 581 |
| | **1,291** | 1,277 |
| **Retained Earnings** | **1,560** | 1,529 |
| | **$12,061** | $11,966 |

## CONSOLIDATED STATEMENT OF CASH FLOWS *(UNAUDITED)*

| *for the three months ended September 30 (in millions)* | **2002** | 2001 | | |
|---|---|---|---|---|
| *for the six Months ended September 30 (in millions)* | | | **2002** | 2001 |
| **Operating Activities** | | | | |
| Net income | **$101** | $90 | **$141** | $164 |
| Adjustments for: | | | | |
| – Depreciation and amortization | **99** | 94 | **201** | 188 |
| – Other non-cash items | **(7)** | 2 | **(5)** | (4) |
| | **193** | 186 | **337** | 348 |
| Working capital changes | **(115)** | (294) | **(92)** | (440) |
| Cash provided by (used for) operating activities | **78** | (108) | **245** | (92) |
| **Investing Activities** | | | | |
| Loan receivable | **(3)** | 22 | **(5)** | 22 |
| Capital asset expenditures | **(197)** | (151) | **(358)** | (279) |
| Contributions in aid of construction | **16** | 19 | **35** | 32 |
| Demand side management programs | **(13)** | (1) | **(19)** | (1) |
| Future removal and site restoration costs | **(3)** | (2) | **(6)** | (3) |
| Proceeds from property sales | **–** | – | **1** | 1 |
| Cash used for investing activities | **(200)** | (113) | **(352)** | (228) |
| **Financing Activities** | | | | |
| Bonds, notes and debentures: | | | | |
| – Issued | **606** | – | **1,007** | – |
| – Retired | **(345)** | – | **(579)** | (104) |
| Revolving borrowings | **(191)** | 84 | **72** | 85 |
| Sinking fund changes | **39** | (15) | **21** | 46 |
| Premium, discount and issue costs | **8** | – | **3** | – |
| Settlements of financial instruments | **22** | – | **22** | – |
| Cash provided by financing activities | **139** | 69 | **546** | 27 |
| **Payment to the Province** | **–** | – | **(333)** | (372) |
| Increase (Decrease) in Cash | **17** | (152) | **106** | (665) |
| Cash at Beginning of Period (Note 1) | **106** | 173 | **17** | 686 |
| **Cash at End of Period (Note 1)** | **$123** | $21 | **$123** | $21 |
| **Supplemental disclosure of cash flow information** | | | | |
| – Interest paid | **$168** | $195 | **$263** | $304 |

[1] Cash at the beginning and end of the period consist of temporary investments.

## OPERATING HIGHLIGHTS *(UNAUDITED)*

| *for the three months ended September 30 (in GW·h)* | **2002** | 2001 | | |
|---|---|---|---|---|
| *for the six Months ended September 30 (in GW·h)* | | | **2002** | 2001 |
| **Electricity Sold** | | | | |
| Residential | **2,800** | 2,784 | **6,093** | 5,958 |
| Light industrial and commercial | **4,072** | 3,974 | **8,087** | 7,937 |
| Large industrial | **3,748** | 3,638 | **7,362** | 7,492 |
| Other energy sales | **265** | 280 | **591** | 626 |
| | **10,885** | 10,676 | **22,133** | 22,013 |
| Electricity trade | **10,325** | 6,254 | **17,320** | 11,194 |
| | **21,210** | 16,930 | **39,453** | 33,207 |
| Number of domestic customers | | | **1,618,942** | 1,601,713 |
| Number of employees | | | **6,064** | 6,202 |

### Business of BC Hydro

British Columbia Hydro and Power Authority (BC Hydro) is a provincial Crown corporation. Our mission is to provide integrated energy solutions to our customers in an environmentally and socially responsible manner.

As one of the largest electric utilities in Canada, BC Hydro serves more than 1.6 million customers in an area containing over 94 per cent of British Columbia's population. Between 43 000 and 54 000 gigawatt-hours of electricity are generated annually, depending upon prevailing water levels. Electricity is delivered to customers mainly through an interconnected system of more than 72 000 kilometres of transmission and distribution lines.

BC Hydro's Board of Directors is appointed by the Lieutenant-Governor in Council and is responsible for the overall direction of the company.

### Regulation

BC Hydro is regulated by the British Columbia Utilities Commission (the Commission), and they are both subject to directions issued by order of the Province. Under Special Direction No. 8, the Commission must allow BC Hydro to achieve a return on equity equal to the return allowed, on a pre-income tax basis, by the most comparable investor-owned energy utility. In the event that BC Hydro's actual return on equity is in excess of that allowed by the Commission, a transfer from net income to the Rate Stabilization Account (RSA) is required for the excess. Where BC Hydro earns a return on equity below that allowed, and there is a balance in the RSA, a transfer from the RSA is required to offset the need for a rate increase. Under Special Directive No. 4, BC Hydro is required to make an annual payment to the Province equal to approximately 85 per cent of its net income, after any Rate Stabilization Account transfers.

L.I. (Larry) Bell
Chair and
Chief Executive Officer

Michael Costello
President and
Chief Operating Officer

## 3. PERFORMANCE MEASURES

### GOALS, OBJECTIVES, AND KEY STRATEGIES

BC Hydro's vision centers on the concept of sustainability. Sustainability is about focusing on financial, environmental, and social value to address the challenges and opportunities BC Hydro faces.

BC Hydro continues to focus on its strengths in financial performance, service quality, environmental management, and employees. Financial Performance means targeting first quartile costs when compared with similar utilities. Service Performance means focusing on customer satisfaction and reliability. Environmental Performance means continuing to manage priority environmental and social issues. Employee Performance means ensuring safety and providing incentives to achieve corporate and personal development goals.

### FINANCIAL PERFORMANCE

BC Hydro's profits are greatly influenced by such uncontrollable factors as precipitation and market prices for electricity. Therefore, to help face the challenge of earning its allowed rate of return, BC Hydro continues to focus on what it can control including cost, optimizing the productivity of its assets, and export and trading opportunities. Additionally, BC Hydro continues with its plans to capitalize on competitive services and alternative delivery opportunities.

### QUALITY OF SERVICE

BC Hydro's service objective is to be a top quartile performer in terms of customer satisfaction and service reliability. This objective will be accomplished by optimizing the utilization and health of Hydro's physical assets including dams, generating stations, transmission and distribution systems, and information technology. BC Hydro also continues to ensure it has public support by maintaining the high reliability of its power system and providing service excellence. BC Hydro's pending partnership with Accenture to provide non-core services includes service agreements that ensure BC Hydro will maintain the same high quality of service.

### ENVIRONMENT

BC Hydro's environmental objective is to be a top quartile performer in terms of sustainability by continuing to manage priority environmental and social issues. This objective will be accomplished by operating in an environmentally and socially responsible manner. Additionally, BC Hydro is changing its future resource mix to focus on effective Power Smart, customer co-generation and self-generation, green energy, and alternative energy. Power Smart is a demand side management program aimed at energy conservation.

### EMPLOYEES

BC Hydro's objective regarding employees is to reinforce the importance of safety and pride in service. This objective will be accomplished by aligning BC Hydro's role and activities as guided by the BC Government Energy Policy and Core Services Review. Additionally, BC Hydro continues to ensure and promote safety. BC Hydro has a Strategic Workforce Planning initiative underway to ensure it maintains a skilled workforce in the face of pending retirements. Since the initiative began, 199 Strategic Workforce positions have been filled. By the end of the year, this total is expected to be 222.

Performance Measures, Targets, and Results

Performance measurement is an integral part of BC Hydro's Strategic Management Process. The tool that BC Hydro uses to assess performance is the Balanced Scorecard. The Scorecard is used to translate Hydro's mission and strategy into tangible measures and targets that drive action. The Scorecard contains a combination of both financial and non-financial indicators.

The development of performance measures is an evolving process. As business needs change, so also must the related measures change. Performance measures have been identified for the majority of BC Hydro's strategic objectives. The following report provides the results for BC Hydro's Q2 fiscal 2003 performance measures against current targets and, where available, historical performance.

**Net Income** (in millions)

| | Actual | Target |
|---|---|---|
| Q2 02/03 | $140.5 | $82.3 |
| Q2 01/02 | $164.3 | $542.7 |

Net Income is an outcome measure of financial performance. Its purpose is to indicate how well BC Hydro is increasing shareholder value by managing the profit side of the economic bottom line. Net Income is defined as total revenue less total expenses.

Net Income was better than target mainly as a result of higher residential revenues due to weather induced demand, higher industrial and commercial revenues due to an increased customer base, and higher industrial revenues due to an increase in production in the pulp and paper, chemical, and mining sectors. An increase in electricity trade spreads (the difference between what BC Hydro pays the market for electricity and what it gets for the electricity it sells to the market) also contributed to the increase over target. Additionally, operations, maintenance and administration costs were slightly better than target primarily as a result of delays in initiatives and other work. Also, energy costs were lower than target due to low cost hydro-generation replacing other higher cost services of supply as a result of higher than average inflows into our reservoirs.

Net Income is projected to be on target by year-end. The higher year-to-date income is expected to be offset by an increase in pension costs as a result of a recent actuarial valuation. The positive variance is also expected to be offset by legal and other costs relating to defending lawsuits brought against Powerex (and other power marketers) by the State of California for allegedly overcharging the State during its power crisis. In addition, BC Hydro is anticipating higher than target finance charges due to expected increases in interest rates. Finally, margins for electricity trading are forecast to be lower than target due to an expected tightening of the electricity market.

Net income year-to-date was lower than for the same period in the previous year. A decrease in electricity trade margins as a result of reduced electricity trade market prices was the primary reason for the unfavourable variance. The decrease in trading margins was partly offset by decreases in operations, maintenance and administration expenses and finance charges.

**Total OMA Cost** (in millions)

| | Actual | Target |
|---|---|---|
| Q2 02/03 | | |
| Operations, Administration | $133.4 | $133.3 |
| Maintenance | $118.0 | $125.2 |
| Total | $251.4 | $258.5 |

Total OMA Cost is a measure of financial performance. Its purpose is to indicate how well BC Hydro is increasing shareholder value by managing the cost side of the economic bottom line. Total OMA cost is defined as the total of operations, maintenance and administration expenditures.

Total OMA Cost was slightly lower than target as a result of delays in initiatives and other work. This positive variance was offset by an increase in legal and other costs relating to the California situation (described in the Net Income measure explanation) and an increase in pension costs as a result of a recent actuarial valuation. As the positive variance is mainly timing related, it is not expected to continue.

### Cost per Customer Transaction (in millions)

| **Consolidated** | Actual | Target |
|---|---|---|
| Q2 02/03 | $ 50.75 | $ 50.48 |
| Q2 01/02 | $122.53 | $162.84 |
| **Domestic** | Actual | Target |
| Q2 02/03 | $ 47.05 | $ 49.38 |

Cost per Customer Transaction is an outcome measure of financial performance. Its purpose is to indicate how proficiently BC Hydro is increasing operating efficiencies and productivity relative to the level of service it provides. Cost per Customer Transaction is defined as total cost divided by total sales volume (megawatt hours sold). The definition of this measure in BC Hydro's Service Plan was based on consolidated numbers. Consolidated Cost per Customer Transaction includes costs and volumes related to electricity trade. The significant drop in the market price of electricity accounts for most of the difference between this year's and last year's results.

Domestic Cost per Customer Transaction does not include electricity trade. With energy trade transactions taken out of the domestic calculation, total domestic costs are lower than target (mainly OMA and energy costs as described in the Net Income measure explanation) whereas domestic sales volume is greater than target (primarily due to an increase in domestic demand also described in the Net Income measure explanation). The combination of these factors led to domestic Cost per Customer Transaction coming in better than target.

### Reliability

| **ASAI** | Actual | Target |
|---|---|---|
| Q2 02/03 | 99.955% | 99.970% |
| Q2 01/02 | 99.968% | 99.973% |
| **CAIDI** | Actual | Target |
| Q2 02/03 | 2.82 Hrs | 2.15 Hrs |
| Q2 01/02 | 2.09 Hrs | 2.15 Hrs |

Reliability is an outcome measure of service quality. Its purpose is to indicate how well BC Hydro is focusing on system dependability. This measure's result demonstrates how dependable BC Hydro's service has been. Reliability is defined as a combination of Average System Availability Index (ASAI) and Customer Average Interruption Duration Index (CAIDI). ASAI is the percentage of time power is available. CAIDI is the average number of hours per interruption. These indices are electric utility industry standards and are used by the Canadian Electricity Association (CEA) in their annual comparison of electric utilities. The indices are calculated on a 12-month rolling average basis.

CAIDI was worse than target mainly due to three major weather events. Even though most of these events took place in the last fiscal year, they impact the current results because CAIDI is measured over a rolling 12-month period. For the current results, this period was October 1, 2001 to September 30, 2002. Over October 22-23, 2001, a windstorm hit the Lower Mainland and Vancouver Island that accounted for 4.0 per cent of the total customer-hours lost during this 12-month period and cost approximately $360,000 to repair. Winds averaging 72 km/hour with gusts of up to 104 km/hour were recorded off West Vancouver's Point Atkinson, 69 km/hour at Victoria and 59 km/hour at Vancouver International Airport. Over December 14-16, 2001, another windstorm struck the Lower Mainland and Vancouver Island that accounted for 34.8 per cent of the total customer-hours lost during this period and cost approximately $1.6 million to repair. Steady winds measured between 80 to 100 km/hour, gusting to more than

115 km/hour in some parts of the Fraser Valley. Icing caused the transmission lines to Vancouver Island to trip, resulting in outages affecting most Vancouver Island customers. On April 14, 2002, another windstorm hit the Lower Mainland and parts of Vancouver Island that accounted for 6.0 per cent of the total customer-hours lost during this period. Gusts of wind as strong as 100 km/hour were recorded in the lower mainland.

Excluding the windstorm of December 14–16, CAIDI would have been 2.26 hours. The severity and number of weather events in this period were in excess of historical levels that were used for setting targets. By the end of the year, many of the events that heavily impacted CAIDI will have dropped out of the rolling 12-month index. However, other events such as the severe storm that took place near Prince Rupert in the early fall will partially offset the positive impact on the index.

ASAI, also measured on a rolling 12-month basis, was impacted to a lesser degree by the above weather events. This means that over the 12-month period, the system was unavailable less than a total of four hours. For the same period in the previous year, the system was unavailable less than a total of three hours.

### Regulatory Compliance

| | Actual | Target |
|---|---|---|
| Q2 02/03 | 9 Incidents | 15 Incidents |

Regulatory Compliance is an outcome measure of environmental performance. Its purpose is to indicate how well BC Hydro is managing priority environmental issues and operating in an environmentally responsible manner. Regulatory Compliance is the number of externally reportable, preventable environmental incidents. This measure is the most visible indicator of environmental compliance to external stakeholders, including the public and regulators.

The target was based on an initial estimate of historical data. Since the measure and target were set, the definition of "preventable" has been further refined. This refinement may result in a lower number of incidents per quarter. This measure is an experiential measure in that it is a new measure for BC Hydro and it is intended to provide organizational focus on reducing preventable incidents.

### Incremental Green Gigawatt Hours

| | Actual | Target |
|---|---|---|
| Q2 02/03 | 0 GWh | 0 GWh |

Incremental Green Gigawatt Hours is an output measure of environmental performance. Its purpose is to indicate how well BC Hydro is managing priority environmental issues by changing its future resource mix to focus on green energy. Incremental Green Gigawatt Hours is defined as additional (not currently in BC Hydro's power system) contracted gigawatt hours from green sources that meet purchase price limits.

Changes to BC Hydro's Green Power acquisition process were recently implemented. The main change was the alignment of the Green Power acquisition to the Customer Based Generation acquisition process to ensure consistency and customer access to both calls for energy supply. This change will result in a delay to achieving our current year target until the second quarter of 2003/2004.

A call of Request for Qualifications took place on October 30. Qualifications will be evaluated to determine the eligibility of potential projects. After projects are qualified and short-listed, qualified bidders will be invited to submit priced bids.

### Incremental Conservation Gigawatt Hours

| | Actual | Target |
|---|---|---|
| Q2 02/03 | 77 GWh | 75 GWh |

Incremental Conservation Gigawatt Hours is an output measure of environmental performance. Its purpose is to indicate how well BC Hydro is managing priority environmental issues by efficiently managing demand for energy through Power Smart programs. Conservation Gigawatt Hours is defined as gigawatt hours saved as a result of economic demand side management.

### Improvement in All Injury Frequency

| | Actual | Target |
|---|---|---|
| Q2 02/03 | 7.6% | 5.0% |

Improvement in All Injury Frequency is an outcome employee measure. Its purpose is to indicate how well BC Hydro is reinforcing the importance of safety by guiding corporate mitigation strategies for managing and preventing all employee work-related injury. Improvement in All Injury Frequency is defined as the percentage reduction in the all injury incident frequency rate (occurrence of Medical Aid and Disabling Injuries). Medical Aid injuries are defined as those where a medical practitioner has rendered services beyond the level defined as “first aid” and the employee was not absent from work beyond time lost on the day of injury. Disabling injuries are defined as those that involve the employee being absent from work beyond the day of injury. The frequency calculation (# of injury incidents x 200,000 / hours worked) is based on injuries experienced at BC Hydro over the previous 12 months and relative to person-hours that have been worked over that same period.

BC Hydro’s All Injury Frequency was significantly better than target mainly due to tremendous organization-wide accident prevention efforts by all BC Hydro employees. BC Hydro’s Field Services organization led the way in the reduction of incident levels. Both medical aid and disabling injuries were reduced during the period, but the most marked improvement was in the more serious disabling category.

### Customer Satisfaction Index

| | Actual | Target |
|---|---|---|
| Q2 02/03 | 85% | 84% |

Customer Satisfaction is an outcome measure of service quality. Its purpose is to indicate how well BC Hydro is focusing on customer expectations in delivering service excellence.

Since the Service Plan was published last February, BC Hydro’s methodology for measuring customer satisfaction has changed. Originally based on a single survey, performed on three customer segments and reported quarterly, Customer Satisfaction is now a composite indicator. Thirty per cent of the measure comes from a survey using all customers as the population from which to draw a random sample. The other 70 per cent comes from transactional surveys using only customers who have had a service interaction with BC Hydro as the population from which to draw a sample. Satisfied customers are those that indicate they are either “satisfied” or “very satisfied”.

BC Hydro believes the new definition provides better insights into the drivers of customer satisfaction. These insights in turn will improve BC Hydro’s ability to take proactive and corrective actions relative to changing levels of customer satisfaction. Along with the definition change, the target was increased from 70 per cent to 84 per cent as the measure now focuses more on satisfaction with actual interaction with BC Hydro and is therefore potentially more controllable. The 84 per cent target corresponds approximately to first quartile performance in the Ipsos-Reid National Omnibus survey that BC Hydro is using as its proxy benchmark.

## ELECTRICITY LOAD

### BC Hydro System

#### Energy Sales

Compared to the previous fiscal year, year-to-date total billed sales were 424 GW·h or 1.9 per cent higher. Of this total, Large Industrial sales were 121 GW·h lower, General sales were 266 GW·h higher, Residential sales were 294 GW·h higher, and Other sales were 27 GW·h lower.

The potential for forecasting errors with Large Industrial sales was considerable due to economic uncertainty. Year-to-date Large Industrial sales were 170 GW·h above plan mainly because of the prudent approach used in developing the fiscal 2003 forecast. On a 12-months basis, Large Industrial sales to the end of September were 1120 GW·h lower than the previous year. Year-to-date Residential sales were higher mainly due to cool temperatures in the spring months.

#### Peak Demand

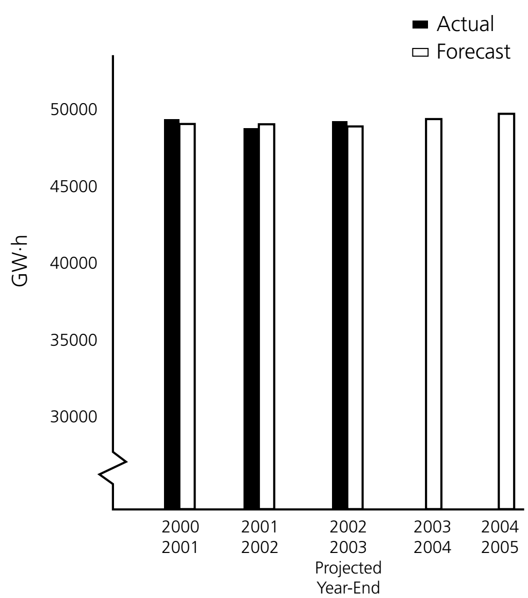
BC Hydro's integrated system demand from domestic customers reached a one-hour peak of 8692 MW on December 4, 2001, at a daily average temperature of +2.2°C.

BC Hydro is a winter peaking utility because of residential electric space heating, and peak demand is much lower in the non-winter months. The domestic integrated system peak was at 6662 MW in September. This compares to a peak demand of 6452 MW in September 2001.

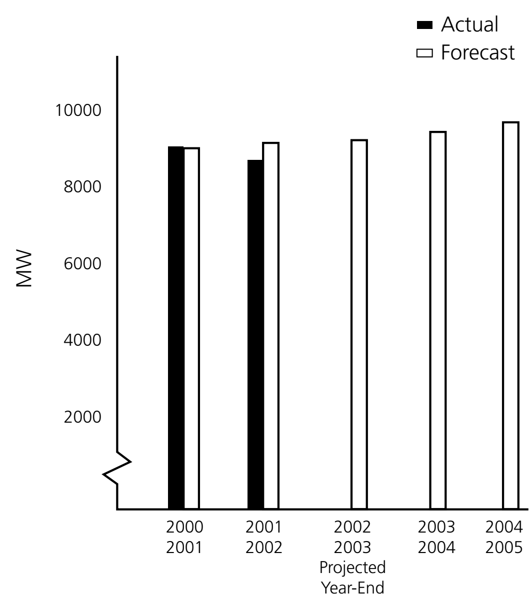
#### Short-Term Forecast

Outside studies and experts indicate that the Canadian economy is expected to continue to perform better than the U.S., and may result in growing needs to raise interest rates in Canada to curtail a potential escalation in inflation. Canada's resource-based exporters will be under increasing pressure to remain competitive.

BC HYDRO SYSTEM–BILLED SALES




BC HYDRO SYSTEM–PEAK DEMAND



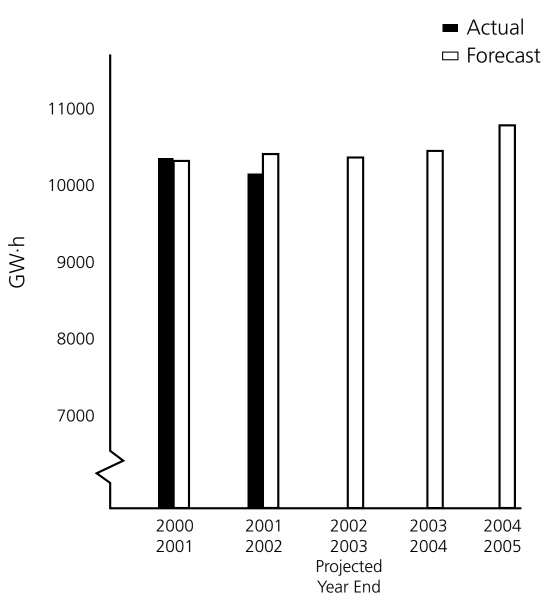
Similar sources indicate that BC's short-term economic forecast is affected by two additional factors: uncertainty over the countervail dispute and the lag between an economic recovery and an increase in commodity prices. Industrial electricity sales are projected to increase over the next six months due to the startup of a new sour gas processing plant, and the restart of a pulp mill under new ownership.

## Vancouver Island (VI)

### Energy Sales

Compared to the second quarter of the previous fiscal year, year-to-date total VI billed sales were 194 GW·h or 4.1 per cent higher. Of this total, Large Industrial sales were 90 GW·h higher, General sales were 45 GW·h higher, and Residential sales were 57 GW·h higher.

VANCOUVER ISLAND–BILLED SALES




Year-to-date Large Industrial sales were 21 GW·h above plan in the second quarter. Due to production curtailments by major VI industrial customers, Large Industrial sales were 282 GW·h or 7.3 per cent lower than the previous year on a 12-months basis. Year-to-date Residential sales were higher in the second quarter mainly due to cool temperatures in the spring months.

### Peak Demand

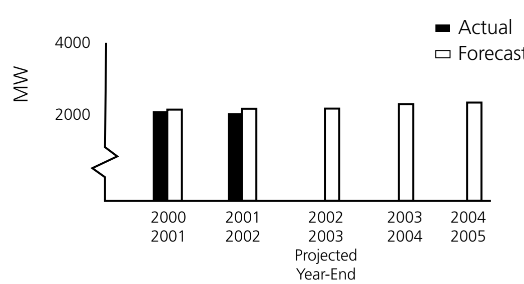
The actual peak for Vancouver Island was 2005 MW, which occurred on December 17, 2001 at an actual temperature of +3.8°C.

Electricity is the primary heating source of about 40 per cent of residential customers on VI. Peak demands are much lower in the non-winter months as a result, and was at 1368 MW in September. This compares to the peak demand of 1413 MW in September 2001.

### Short Term Forecast

Dominant industries on VI are all related to the forestry sector. Outside studies and experts indicate that difficult market conditions confronting VI's lumber production are expected to continue in the short-term, due to the countervail duty and a weak Japanese economy.

VANCOUVER ISLAND–PEAK DEMAND



## ELECTRICITY AND GAS PRICES

BC Hydro tracks market information that forms the basis for its future price forecasts for both natural gas and electricity.

### Forward Market Information

In the short term, BC Hydro tracks "forward prices," which are market price quotes on transactions for delivery at a specified time and delivery point. For electricity, the nearest (liquid) delivery point is Mid-Columbia, and in the case of natural gas it is Sumas.

Market forward quotes are readily available for a period of up to two years for electricity and for three to five years for gas. Forward prices for both electricity and natural gas can be volatile, but they provide an important near-term reference point since they reflect all the information currently available to market participants.

### Longer-Term Market Fundamentals

The longer-term forecast —available from a number of specialized forecasting groups—is based on representing the supply and demand for electricity and of cost drivers expected to prevail. Key factors in the long-term forecasts are:

- the expected stock and availability of generating units (especially new units);
- the expected level of fuel prices and other costs of operating generating units;
- the level of demand as driven by forecasts of economic activity, technology and conservation efforts; and
- the expected state of the regulatory or market environment.

BC Hydro acquires the output and market analysis of a number of third-party forecasts to supplement its long term forecasting activities.

### 2002 compared to 2001

Present prices for both electricity and natural gas remain low compared to 2001 but show signs of a modest recovery in late 2002, as suggested by the forward markets.

Among the reasons for this are:

- the U.S. recession (reducing demand for natural gas and electricity);
- significant new generating supply and natural gas wells coming into service;
- relatively high gas storage inventories (compared to last year and the average for the past five years); and
- improved hydro conditions.

Lower prices have resulted in lower high-load hour to low-load hour differentials, since these tend to be positively correlated with absolute price levels. Further, seasonal spreads have decreased as a result of an abundant supply of hydro resources in the Pacific Northwest combined with reduced industrial loads.

### 2002/03 Outlook

The economic outlook remains uncertain, clouded by recent stock market declines and prospects of war. Most observers continue to forecast positive economic growth by the end of the year, although at a slower pace. Exploration and drilling activity has slowed resulting in a decline in natural gas production, while the predicted improvement in the general economy would serve to tighten the supply-demand balance for natural gas and cause an upward pressure on prices.

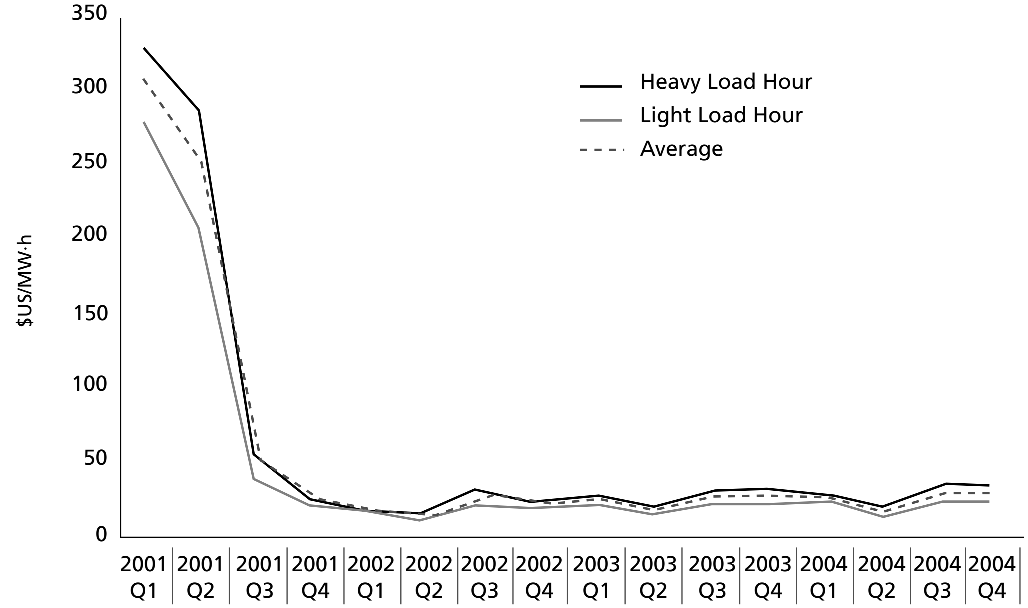
The onset of winter will increase demand for both gas and electricity.

The combination of higher prices for natural gas and increasing electricity demand should lead to an increase in electricity prices. However, other factors may impair the price recovery, including:

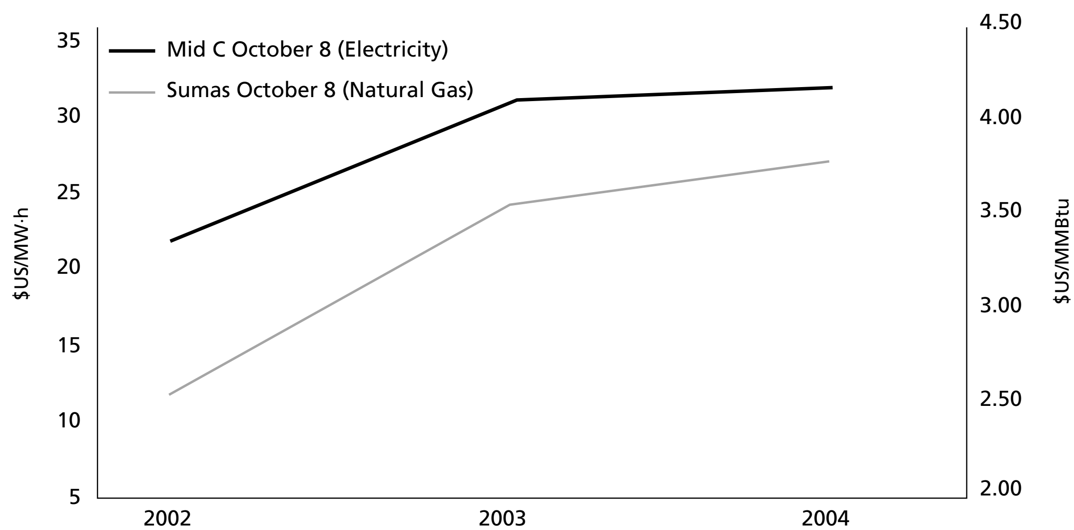
- economic recovery may be sluggish or fail completely;
- significant new generating capacity despite cancellations; and
- more normal regional hydro conditions.

In the longer term, price expectations are based on a supply-demand balance reflective of average economic growth and demand. Prices of both electricity and gas are expected to grow moderately, modulated by seasonal factors.

## HISTORIC MID-C ELECTRICITY PRICES AND MARKET FORWARDS



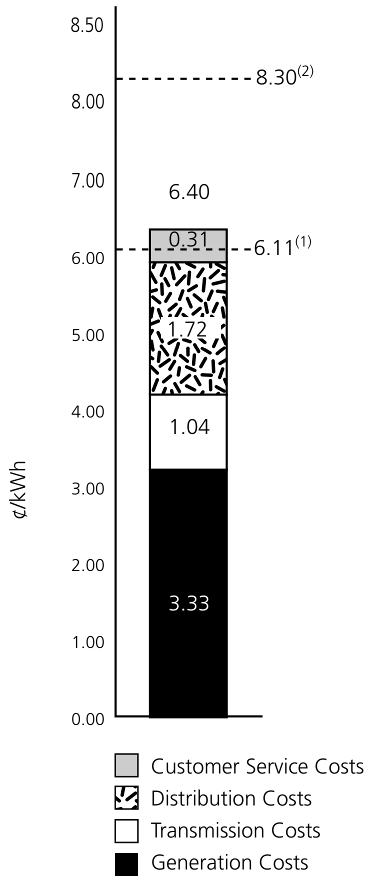

## MID-C ELECTRICITY MARKET FORWARD PRICES AND SUMAS NATURAL GAS



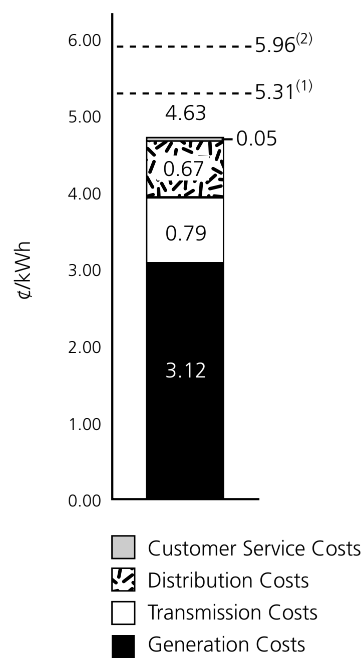
## BC HYDRO 2002 COST TO PROVIDE SERVICE

The following graphs present an estimate of the cost of providing service to each customer class (in cents / kWh), based on an allocation of BC Hydro's 2002 actual costs.  This analysis was done by applying the 1997 Fully Allocated Cost of Service Study, which was used in establishing BC Hydro's current Wholesale Transmission Services tariffs, to the 2002 actual costs. For comparative purposes, the existing BC Hydro Tariff for each customer class has been included and is represented by the dotted line accompanying each graph (see note 1).

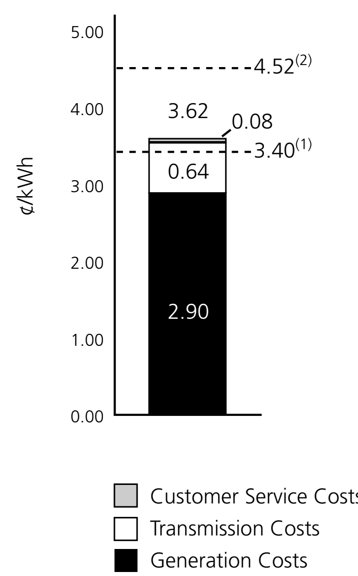
**Residential Class**
**(Single-family dwellings, e.g. detached house)**




**General Service Class**
**(small to large commercial properties, e.g. schools)**




**Transmission Class**
**(Rate 1821, where supply is 60000 volts or higher, e.g. pulp mill)**




(1) Existing BC Hydro Tariff.

(2) Estimated cost of service if the BC Hydro revenue requirements were recovered completely through domestic rates.

The information presented in this analysis is based on preliminary estimates and is derived through the use of historical allocation methodologies.

These charts are intended to show how BC Hydro's actual costs can be allocated to customer classes, based on the analysis outlined below. They are not intended to indicate what BC Hydro's rates may be after the expiration of the current rate freeze. Income from export activities and transfers from the Rate Stabilization Account (RSA) are included in the determination of Allowed Return on Equity, consistent with the terms of Special Direction No. 8 to the BC Utilities Commission. If these amounts were removed from the Allowed Return on Equity calculation, the cost of service would be significantly higher (see note 2). Generation costs for fiscal 2002 include costs for hydro and thermal generation, as well as purchases from independent power producers and the marketplace. Hydro generation (which has the lowest cost of production of the various energy sources) was lower than normal for fiscal 2002, due to lower opening storage levels and reduced system inflows during the year. This resulted in a greater portion of domestic energy requirements being met by thermal generation and the marketplace. If this analysis assumed average water conditions for hydro generation for fiscal 2002, domestic energy costs would have been significantly lower and the resulting cost of service amounts for each customer class would also have been lower.

This analysis does not reflect the reorganization of BC Hydro's operations into the Lines of Business structure. Under the Lines of Business structure, different allocation factors may be appropriate to accurately reflect cost causation.

The BC Hydro system is designed and operated in order to meet customers overall electricity requirements and peak demand loads. As such, Generation, Transmission and Distribution costs are allocated amongst the customer classes, based in part on the demand and consumption profiles of each customer class, in order to reflect the cost of providing service to that class. Generation costs include fixed and variable energy costs and are allocated amongst the customer classes based on demand profiles and also consumption profiles. Transmission costs are allocated amongst the customer classes based on the customer class demand profiles. Distribution costs are allocated amongst the customer classes based on demand profiles, customer numbers and the direct assignment of costs.

These graphs are presented as a matter of public information. The future determination and treatment of the rates to be charged to each customer class will be determined though the regulatory process.

## Snowpack

BC Hydro has large reservoirs on the Peace and Columbia River systems as well as smaller reservoirs on the Coast and Vancouver Island. Based primarily on snowpack measurements, water supply forecasts are made for the February through September period. The observed water supply for this year is summarized below.

## Peace River System

For the Peace River basin, in a typical year, snowmelt provides approximately 50 per cent of the annual runoff and spring/summer rainfall provides the other 50 per cent. Basin inflows for the February–September period were 24 per cent above average due to an above average winter snowpack as well as above average spring/summer rainfall. These very high runoff conditions resulted in spills at our G.M. Shrum and Peace Canyon generating stations during the month of July.

## Columbia River System

For the Columbia River basin, in a typical year, snowmelt provides approximately 70 per cent of the annual runoff and spring/summer rainfall provides the other 30 per cent. Streamflows were near average for the February–September runoff period; Kootenay River basin streamflows for the same period were slightly above average.

## Bridge River System

For the Bridge River system, in a typical year, snowmelt provides approximately 50 per cent of the annual runoff and rainfall provides the other 50 per cent. Streamflows were near average for the February–September runoff period and reservoir levels in the Bridge River system are near normal for this time of year.

## Coastal Projects

For the Coastal projects, in a typical year, snowmelt provides approximately 30 per cent of the annual runoff and rainfall provides the other 70 per cent. Most of the Lower Mainland reservoirs had near normal inflows during February to September. The exception to this was the Alouette basin, which had above average water supply for the February–September period.

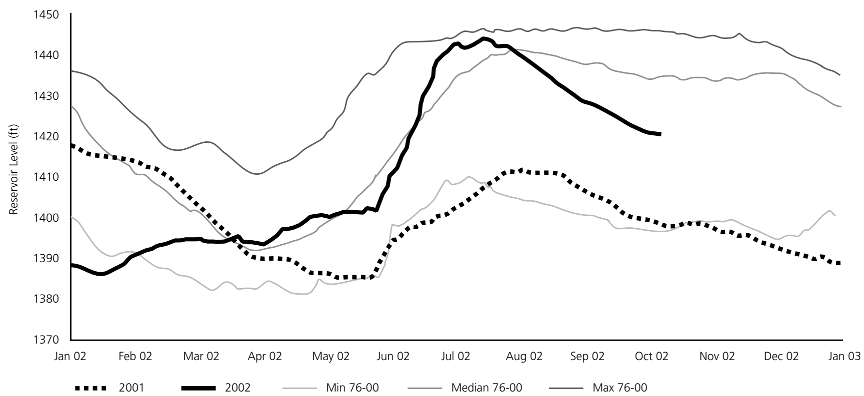
For Vancouver Island, in a typical year, snowmelt provides approximately 30 per cent of the annual runoff and rainfall provides the other 70 per cent. The Campbell River, Comox, and Elsie reservoirs had very low water supply conditions due to a very dry spring and summer.

Rainfall throughout southern B.C. during the late summer and early autumn period has been well below normal. As a result, Coastal project reservoir levels are now generally below normal. A number of the coastal reservoirs (Jordan, Campbell, Comox, Elsie, Coquitlam, Alouette, Stave) have levels that are well below normal for this time of year. Continued below normal rainfall (resulting in the driest October on record) resulted in critical water situations at many coastal facilities until the fall rains began in early November.

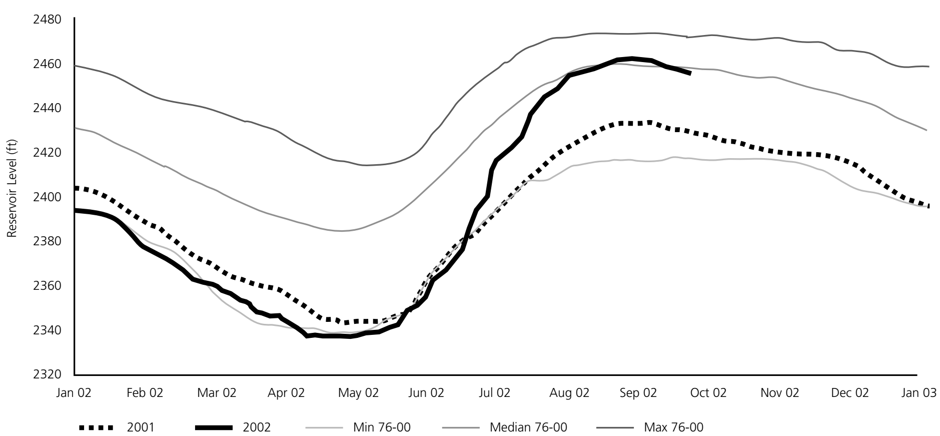
## Reservoir Levels

BC Hydro monitors the levels at all of its hydroelectric reservoirs to ensure the most efficient system integration and operation. The relative reservoir levels at any time are a function of precipitation (rain and/or snowmelt that fills the reservoirs) and electricity demand (as the water in the reservoirs is used to turn turbines and produce electricity).

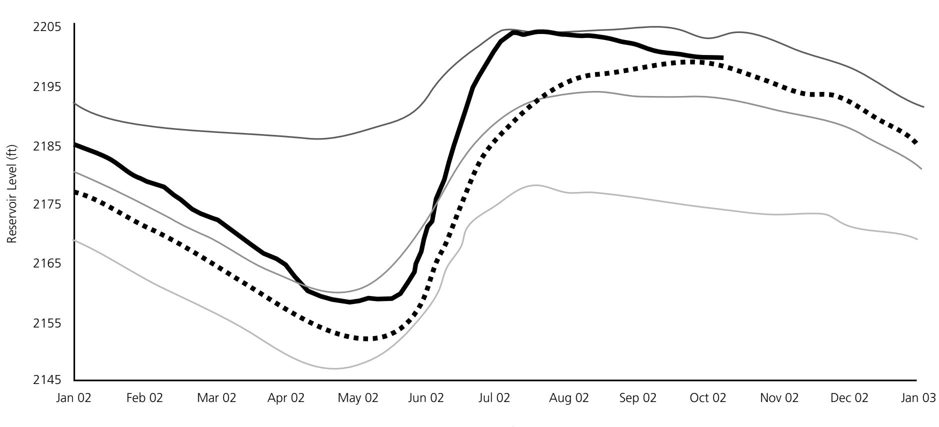
## ARROW RESERVOIR LEVELS




## KINBASKET RESERVOIR LEVELS




## WILLISTON RESERVOIR LEVELS



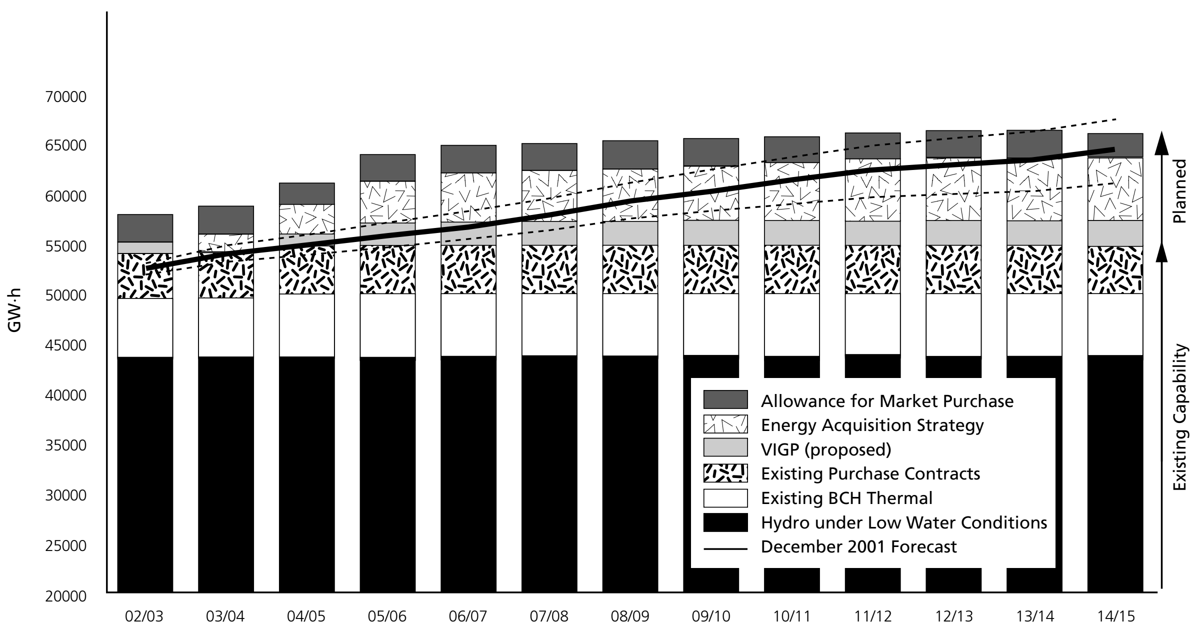
RESOURCES

## Load Resource Balance

BC Hydro plans and operates its system to ensure that it meets the electricity needs of customers both now and for the future. The goal is to make sure there is enough electricity supply to meet the "load" (or electricity demand) by using a range of existing and future resources. These resources—and their relative contributions to the BC Hydro system—are shown in the following charts. These charts reflect the capability of the resources in BC Hydro's supply portfolio rather than expected generation. In BC Hydro's annual planning cycle, these charts are typically updated during the second half of the fiscal year.

### SYSTEM FIRM ENERGY AND CAPACITY SUPPLY-DEMAND BALANCES

The System Firm Energy Supply-Demand Balance below compares annual energy demand (net of current Power Smart programs) to the energy capability of existing and planned new facilities.




## Assumptions

Under "Hydro under Low Water conditions":

- Lowest historical streamflow conditions which were experienced between September 1942 and April 1946.
- Full use of storage capability of the major reservoirs.
- Contribution from Arrow Lakes Hydro (formerly Keenleyside). Generation from Arrow Lakes Hydro is purchased from Columbia Power Corporation under a long-term purchase agreement starting from January 2003.

In "Existing BCH Thermal":

- Maintenance activities at Burrard Generating Station have increased due to the age of the facility. At the end of the second quarter, three units were available and the plant's energy capability for the balance of the fiscal year was about 1500 GW·h with a firm capacity of 450 MW. This capability will be adequate to meet domestic load this fiscal year. If economic, maintenance on the additional units could be accelerated. The fully restored annual capability of Burrard Generating Station is 6100 GW·h (and 912 MW net).
- Prince Rupert Generating Station (46 MW)

In "Existing Purchase Contracts":

- Pre-2001 IPP Contracts
- Alcan

In the "Energy Acquisition Strategy":

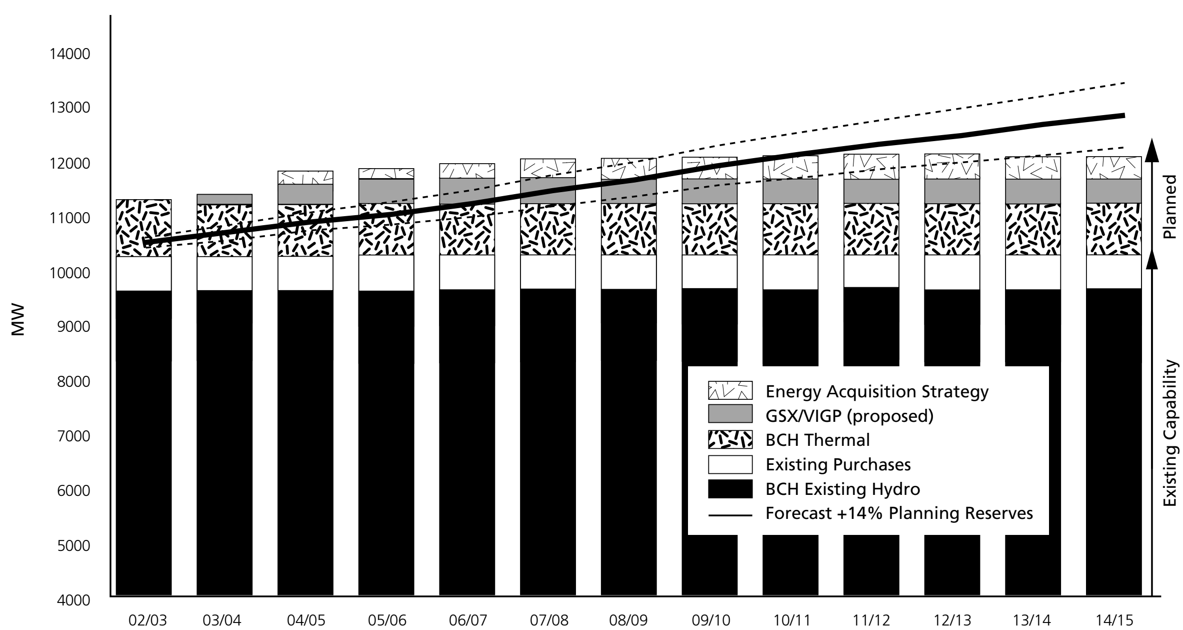
- The balance of planned Power Smart
- Additional Resource Smart
- New Green and the expected 800 GW·h (100 MW) from the current Customer Based Generation call for proposals.

In "December 2001 Forecast":

- Current Power Smart Programs

## SYSTEM DEPENDABLE CAPACITY SUPPLY-DEMAND BALANCE

The System Dependable Capacity Supply-Demand chart compares the forecast peak electricity demand (peak winter usage) – plus required capacity reserves – to the dependable capacity of existing and planned facilities.



## Assumptions

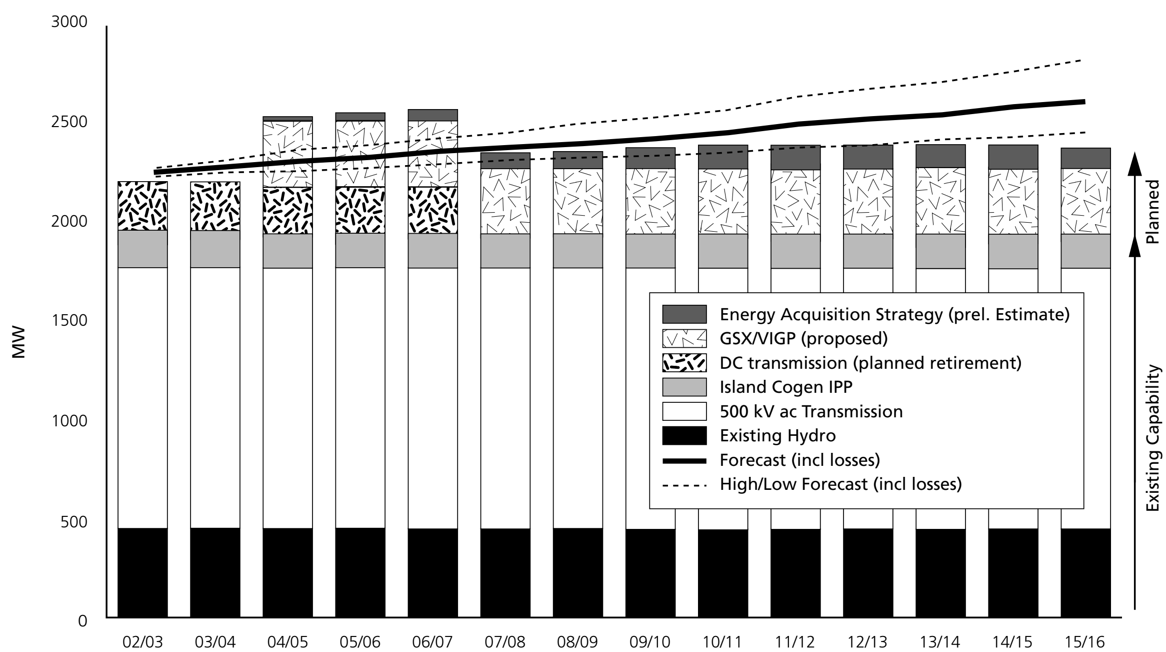
Capacity and Planning Reserves: BC Hydro is obligated to maintain operating reserves set by the Western Electricity Coordinating Council (WECC). For the BC Hydro system this is about 7-8 per cent of load. In addition, the WECC recommends that each utility carry sufficient capacity reserves to allow it to withstand the temporary outages of generating units. Based on loss-of-load analysis, for the BC Hydro system this criterion can be met by maintaining capacity reserves of approximately 14 per cent of dependable capacity supply. Since BC Hydro is interconnected with other systems, up to 400 MW of capacity from imports is assumed available.

The fall of 2004 has been the target in-service date for the Vancouver Island Generation Project and the Georgia Strait Crossing (GSX) pipeline to Vancouver Island. A more conservative in-service date of 2005 is shown here. This more conservative date has become a possibility due to delays by the National Energy Board in its regulatory review of GSX.

The Energy Acquisition Strategy dependable capacity contribution is conservatively estimated. That is because dependable capacity – the megawatt output a generator can reliably provide to meet peak electricity demands – is project specific. The dependable capacity contribution of a generator is based on an 85 per cent confidence level that its capacity (MW) output can be available coincident with winter peak demand. This estimate also includes the current estimate of the peak demand reductions attributed to Power Smart. Power Smart peak reductions will depend on the extent to which the electricity savings coincide with the system peak demand.

### VANCOUVER ISLAND DEPENDABLE CAPACITY SUPPLY-DEMAND BALANCE

Separate information is provided for Vancouver Island (VI) because that is where BC Hydro's customers are most urgently in need of new electricity generating resources for capacity (i.e. the total amount of electricity that can be produced and available at any one time).



## Assumptions

- "Forecast" is the December 2001 Forecast which includes approved Power Smart. Transmission losses have also been included.
- "Reliability Planning Criteria" are such that the system should be able to withstand loss of any single element with no loss of customer load. Therefore, VI firm supply is planned with the largest element - one alternating current (ac) cable circuit - unavailable.
- "Dependable Winter Capacity" of the existing VI hydroelectric system is 448 MW.
- "Continuous Rating" of the 500 kV cables is 1200 MW. Their short duration overload capacity is 1300 MW (shown here).
- "HVDC" is the high voltage direct current submarine cable system to Vancouver Island. Due to its deteriorating condition, its remaining firm (dependable) delivery capability is 240 MW, with expected end of life in 2007.
- "Island Cogen IPP" has a winter dependable capacity of 240 MW, but that is limited until GSX is in service and supplying gas or until the unit can be run on backup distillate fuel.
- The fall of 2004 has been the target in-service date for the Vancouver Island Generation Project and the Georgia Strait Crossing pipeline to Vancouver Island. A more conservative in-service date of 2005 is shown here. This more conservative estimate has become a possibility due to delays by the National Energy Board in its regulatory review of GSX.
- "Energy Acquisition Strategy" is expected to provide additional dependable capacity on Vancouver Island.

GENERATION

## Introduction

The Generation Line of Business is responsible for all of BC Hydro's integrated electricity generating facilities and reservoirs in the province.

## Initiatives

### Green Independent Power Producers (IPPs)

- By the end of the second quarter, one contract was executed and approximately 153 GW·h/yr was added to our total green energy purchased.  This contract was part of the fiscal 2002 call process and was applied against our green energy target for fiscal 2002.
- The target for fiscal 2003 is five to ten new contracts, equalling 350 GW·h/yr in green energy. BC Hydro will issue another call for green energy in October 2002 for up to 800 GW·h/yr. The intent of the call is to assure that BC Hydro can reach the 350 GW·h/yr target.
- In September 2002, BC Hydro launched its new Green Power Certificates (GPC) product for business customers. GPCs are a simple, practical and innovative way for organizations to tangibly demonstrate corporate values and help lead the way to a more sustainable future. The objective is to create market-driven demand for more green electricity development in B.C. Sixteen charter purchasers—ranging from municipalities to universities to businesses—purchased a total of 3950 MW·h of GPCs during the product launch. An additional sale has been made in the electricity marketplace to the Los Angeles Department of Power and Water. Residential customers continue to benefit through Hydro's commitment to meet 10 per cent of new demand through green sources.

## Alternative Energy

### 20MW Demonstration Project on Vancouver Island

| Project Component | Status to 30 September 02 |
|---|---|
| 10 MW Wind Energy Project | New Key Principles Agreement with revised roles for AXOR and BCH under development. This two-phased approach will involve a 3 MW test bench built by AXOR followed by scaling up if site proves viable.<br><br>Environmental and socio-economic studies submitted to Land and Water BC for review in support of BC Hydro's Crown Land Application. |
| 3-4 MW Wave Energy Project | Meetings conducted with Energetech and Ocean Power Delivery to discuss capitalization of the projects, royalties and sharing risk and debt recourse.<br><br>Risk assessment of Energetech's technology and construction processes conducted to mitigate any unmanaged risk.<br><br>Met with NRCan, Environment Canada and Industry Canada in Ottawa to discuss partnership and funding opportunities for projects. |
| 6-8 MW Micro Hydro Project | MOU signed with Synex with a second MOU with Innergex pending. The objective of the MOUs is for BCH to gather information about the development process as Synex and Innergex build their projects. |

### Customer-Based Generation

BC Hydro is seeking ten to 20-year agreements to supply new, competitively priced electricity totalling 800 GW·h/yr from customer-based generation. In response to a Request for Qualifications, BC Hydro received 38 proposals from customers from all sectors across the province. On September 6, a shortlist of 22 proposals was announced and these projects were invited to participate in the Call for Tender process. The Electricity Purchase Agreement (EPA) for BC Hydro's customer-based generation program has been standardized for all bidders and posted on Hydro's Web site and a workshop for potential bidders will be held on November 4.

### Resource Smart

The Resource Smart program was initiated in 1988 to identify and implement economic efficiency gains at existing BC Hydro facilities to provide more energy. To September 30, 2002, 1612 GW·h of restored and new energy have been brought into service. Currently there are 15 projects funded and underway, with four in the "Implementation Phase" (590 GW·h/yr) and 11 in the "Definition Phase" (445 GW·h/yr). The weighted average cost of energy from projects in the implementation phase is $2.1¢/kW·h. The weighted average cost of energy for projects in the definition phase is $2.95¢/kW·h.

Since March 2002, one project has been completed, Peace Canyon Tailwater Improvement Project (49 GW·h/yr), and two more of six units being upgraded at Bridge River (28 GW·h/yr) were completed. The last two units to be upgraded at Bridge River are planned for completion in mid-2003. The Seven Mile Unit 4 project is one year ahead of schedule and on track to come in under budget.

### Facilities

BC Hydro takes great care maintaining the hydro-electric and thermal generating facilities within its system. As much as possible, outages are scheduled to minimize any financial or customer impacts. The following are large unit outages planned for the Hydro system, through to December 31, 2002.

### Peace Generation Area

- *G.M. Shrum* – one unit on overhaul through to early December and one unit on overhaul through to mid-November.
- *Peace Canyon* – two units sequentially on outage for the first half of October.

### Upper Columbia Generation Area

- *Mica* – one unit on overhaul for three weeks in October /November.
- *Revelstoke* – one unit on overhaul in October for one week.

### Kootenay Generation Area

- *Seven Mile* – one unit on overhaul through late October.
- *Kootenay Canal* – two units on sequential overhaul over October and November.

### Thermal Generation Area

- *Burrard* – Burrard generation for fiscal year 2003 is currently forecasted to be approximately 160 GW·h, due to the current low prices of electricity on the market. Burrard is a critical resource for BC Hydro. Always a source of emergency generation close to the major load centre of the Lower Mainland, it traditionally operates between late spring and early fall to support and back-up Hydro's predominately hydroelectric facilities (which are dependent on rain and snow runoff). However, it should be noted that Burrard generation varies with system conditions, inflows, and the market price of potential energy imports. Burrard also plays a valuable role to stabilize voltage in the transmission system when operating in the "synchronous condense" mode.
  - Three Burrard units are available for generation and two units are available for system support (synchronous condenser operation) from now through to the end of December.

- A digital control system is being installed on the sixth unit, which will not be available until the end of March.

- ***Fort Nelson*** – A four-day outage is planned for the week of October 15.
- ***Prince Rupert*** – the plant is not operating due to the high cost of production versus the low cost for other available power.

## Dam Safety

In July 2002, the reservoir behind the WAC Bennett dam reached full pool for the first time since 1985. This was the highest reservoir level since the sink-holes were repaired in 1997. Consequently, during the period of high reservoir level, BC Hydro's Dam Safety staff closely monitored the performance of the dam by means of increased frequencies of physical inspections and instrument readings. As a prudent dam safety measure, the reservoir level was regulated from rising significantly above its full pool by releasing excess inflows from snowmelt and rainstorms through the spillway for several weeks. Environmental impacts due to spilling were carefully monitored and communicated to various agencies.

The anchoring project commenced at Seven Mile dam with the preparation and award of Phase 2 contracts. The anchoring work is part of a series of dam upgrades at Seven Mile which include improving the reliability of spillway operation and improving site systems related to dam safety. The dam upgrades are expected to be complete by 2005; the approved cost is up to $100 million. In addition, the prospectus for decommissioning Coursier dam was completed.

## Introduction

BC Hydro's high voltage transmission system transports bulk electricity from generating plants to substations across the province, and to interconnection points in the western North American grid to enable energy markets. The transmission system and associated facilities are the responsibility of the Transmission Business.

## Highlights

### RTO West

BC Hydro collaborated with nine western U.S. utilities to develop a model for a Regional Transmission Organization—RTO West—and filed a proposal with the U.S. Federal Regulatory Commission (FERC) at the end of March. FERC issued a Declaratory Order on the RTO West Stage 2 filing on September 18. The Commission was highly complimentary of the RTO West filing and the Order is generally beneficial to BC Hydro and Powerex. RTO West has between 90 and 120 days to make various filings to address issues raised in the Order. BC Hydro is participating actively in the RTO West process including establishment of implementation plan milestones to ensure coordination of BC activities. The BC implementation would be specifically tailored to the BC Energy Policy and FERC requirements for international participation. Involvement in RTO West provides continued opportunities for BC participation in a broader North American energy market.

FERC issued a notice of proposed rulemaking (NOPR) on July 31 directed at remedying undue discrimination through open access transmission service and standard market design (SMD). BC Hydro and Powerex have been actively engaged in FERC's consultation process leading to release of the NOPR. The SMD NOPR is a new set of standardized rules that will govern the wholesale electricity industry, intended to address current inefficiencies in the wholesale market and provide customers with the benefits of a competitive bulk power system. BC Hydro is reviewing the impacts of the NOPR, in consultation with RTO West, and may participate in FERC workshops related to the SMD. Although many questions remain to be answered and issues addressed through the consultation process, the new NOPR is a major step forward towards standardizing electricity market design across North America.

RTO West will coordinate regional transmission operations, providing more efficient access to all transmission facilities owned by the participating entities for bulk power transfers. The current regional planning process is fragmented and lacks investment due to divided responsibility among vertically integrated utilities. One of the key responsibilities of RTO West will be to plan necessary expansions to remove growing congestion on the transmission system and facilitate an effective investment and cost recovery process. This is expected to achieve the vision of an electricity common carrier in the region that will efficiently link generation resources to customers.

### Metropolitan Lower Mainland Transmission

A number of operational challenges have been experienced on the 230 kV underground transmission cables serving the metropolitan area of the Lower Mainland. Many of these cables were installed in the late 1950's and are reaching the end of their operational life. Failures have occurred on several circuits. The 230 kV system is vulnerable and has little flexibility for operation and maintenance, leading to increased risk of customer outages.

Underground cable circuit 2L64 failed on July 10, forcing South Vancouver and Point Grey customers connected to Sperling and Camosun substations to be supplied from a single cable circuit, increasing the risk of significant customer outages should this circuit fail before 2L64 is repaired. A temporary transformer was installed at Sperling substation to permit customers to be supplied if the remaining cable circuit fails. This involved the transportation of a 400 000 kg transformer from Surrey to Vancouver and several upgrades to the transmission and substation facilities, all completed over an extremely short time span of 11 days. The 2L64 cable circuit will be returned to service in early November.

Engineering, material acquisition and public consultation are underway for installation of a new underground 230 kV cable circuit 2L33 between Horne Payne and Cathedral Square substations. Application for a Certificate of Public Convenience and Necessity (CPCN) was also filed with the BCUC. This $43.8 million project will help to secure reliable supply to downtown Vancouver and is part of Transmission's long-term development plan for the metropolitan Vancouver system to address aging infrastructure and seismic concerns.

A new 230 kV underground cable, part of circuit 2L40 between Burrard Thermal generating station and Newell substation, was placed in service on September 23rd. A similar replacement of the cable portion of circuit 2L39 from Meridian substation to Newell substation was completed last year. This now secures the transmission supply to Burnaby customers supplied from Newell substation.

### Vancouver Island Supply

Several significant maintenance activities have been undertaken to improve reliability of transmission supply to Vancouver Island over the winter months. Insulators were washed on a section of the 500 kV AC lines exposed to salt spray and salt fog pollution. This involved helicopter access and development of new work methods. Capacity of the High Voltage Direct Current (HVDC) system had been reduced following the failure of one section of submarine cable earlier this year, and a second section of cable is at risk of failure. The remaining HVDC cables are being reconfigured to increase the capacity and reliability of the HVDC system.

### Other Transmission

An engineering review of transmission circuits 2L9 and 2L13 between the Squamish area and North Vancouver identified concerns with inadequate clearance between conductors and the ground. Emergency repairs were completed on 2L9 by August 24 and on 2L13 by August 31.

Portions of the transmission system in the Revelstoke area have been upgraded from 46 kV to 60 kV between Illecillewaet substation and Walter Hardman generating station. This work is in preparation for the 60 kV connection to the 30 MW Pingston IPP this fall.

DISTRIBUTION

## Introduction

There are over 55 000 kilometres of overhead, underground and submarine distribution lines in B.C. as well as 865 000 power poles. These are the responsibility of BC Hydro's Distribution Line of Business, which is part of the Crown corporation that directly serves our 1.6 million customers and 6000 non-integrated customers in nine remote communities.

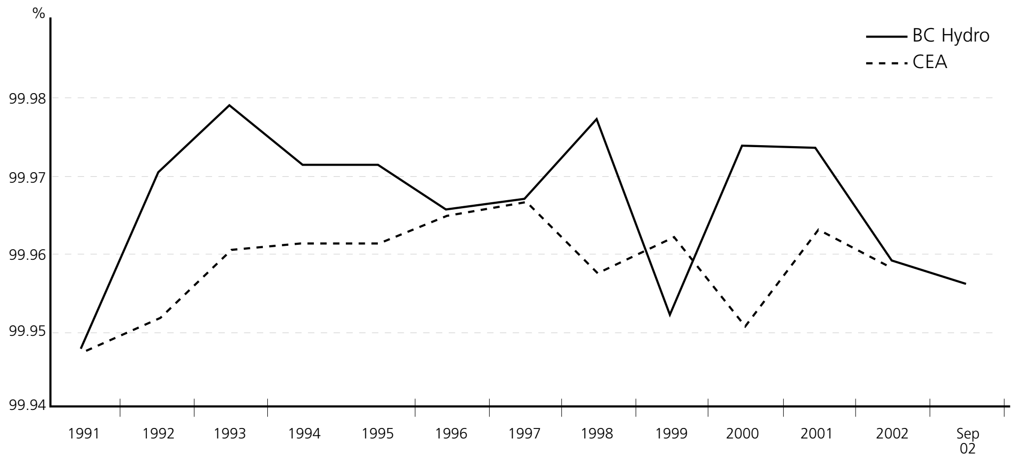
## Highlights

- PowerON, the computerized telephone access system, is being phased in and now services 1.4 million of our 1.6 million customers. Areas now served by PowerON include all of the Lower Mainland, Southern Interior, South Vancouver Island and Nanaimo, Parksville, Prince George and Mackenzie. Service to other districts will be phased in over the next six months.
- New customer additions totalled 9194 for the first two quarters, an increase of 16.4 per cent over the same period last year. This upward trend is expected to continue for the remainder of the fiscal year.
- As the BC Hydro distribution plant continues to age, we are seeing the need to increase maintenance costs in critical areas for both the overhead and underground systems. In addition, the average utilization factor for circuits around the province continues to increase and now averages 67 per cent overall. Many circuits in urban areas have registered a utilization exceeding 90 per cent, placing significant electrical and mechanical stress on the systems and reducing expected life and increasing maintenance costs. Specifically, Distribution has undertaken the following maintenance changes for fiscal 2003 to meet some of the challenges:
  - Maintenance inspections increase from $2.6 million to $3.3 million
  - Pole refurbishing increase from $0.8 million to $1.7 million
  - Cutout replacements increased from $2.0 million to $ 2.4 million
- A specific maintenance program has been completed for the Port Simpson area and, in the short-term, all of the faulty insulators identified through a recent infrared survey have been replaced. These insulators, which failed during the drier summer period, have been sent to Powertech labs for analysis and a program for complete replacement will be completed in the spring. In addition, all northern coastal communities are under review to ensure that similar insulator failures will not occur.

## Reliability

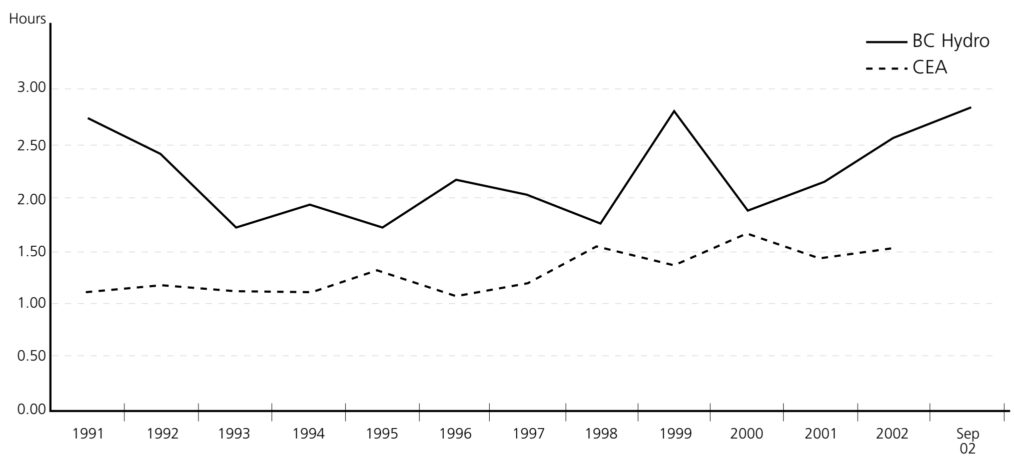
1. ASAI is a measure of overall system reliability, indicating the percentage of time power is kept on during a year.

AVERAGE SYSTEM AVAILABILITY INDEX (ASAI)




2. CAIDI is a measure of the amount of time an interrupted customer is without power during a year.

CUSTOMER AVERAGE INTERRUPTION DURATION INDEX (CAIDI)



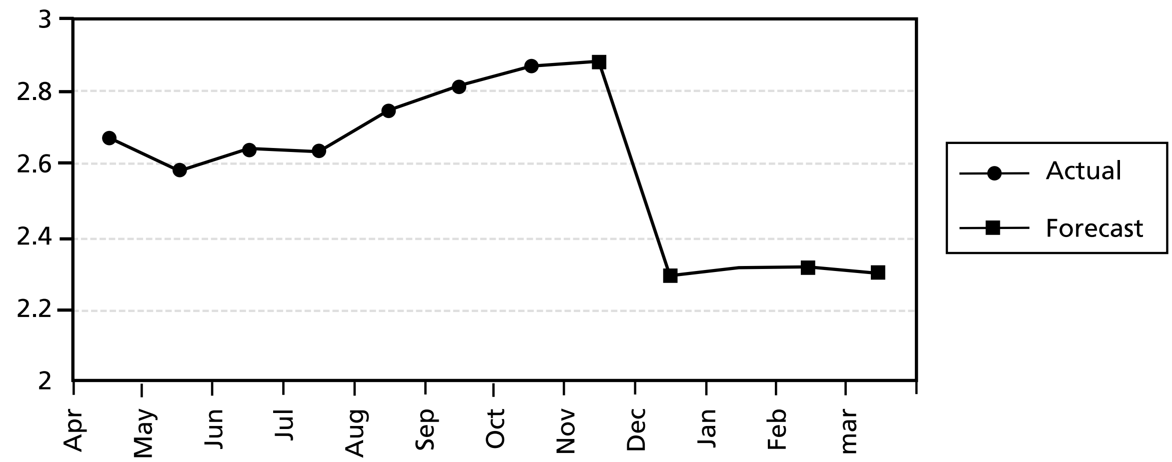

**Reliability (**12 month year-to-date (to September 30, 2002)

| | **Actual Reliability** | **Target Reliability** |
|---|---|---|
| ASAI | 99.955% | 99.970% |
| CAIDI | 2.82 hours | 2.15 hours |

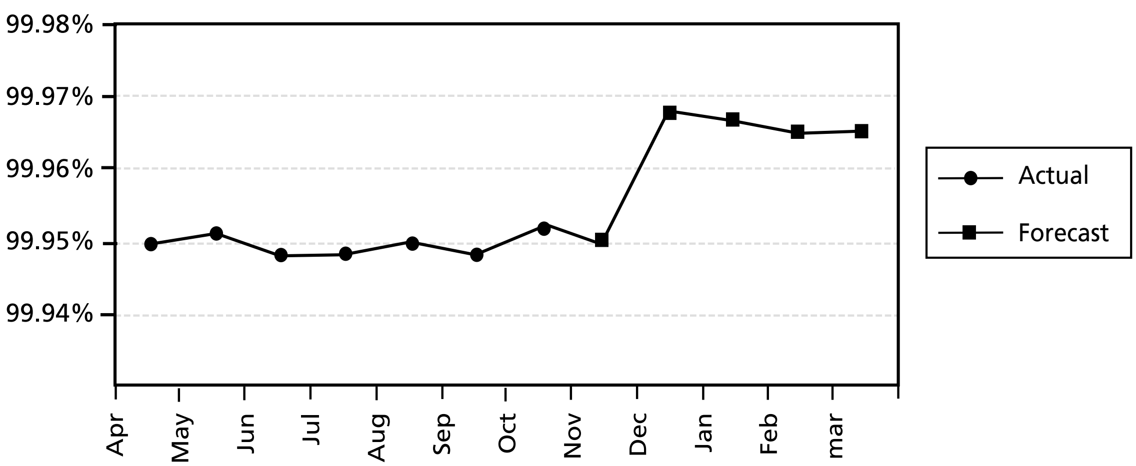
Distribution reliability has generally been improving over the past ten years, with ASAI and CAIDI averaging 99.969 and 2.08 hours respectively. BC Hydro uses a 12-month rolling average for these measures. Consequently, due to several major storms in December 2001, the statistics for the first two quarters of fiscal 2003 fell below the reliability targets. Excluding the storms of December 14–16, 2001, ASAI was 99.970 per cent and CAIDI was 2.26 hours.

Below are forecast charts for the end of the fiscal year for both CAIDI and ASAI.

ROLLING 12 MONTH CAIDI FORECAST




ROLLING 12 MONTH ASAI FORECAST



## Introduction

Engineering provides project management, maintenance, emergency response, design, contracts and construction management services to the Generation, Transmission and Distribution Lines of Business, and selected external clients. Second quarter activities have focused on the delivery of engineering services within scope, schedule, budget, and with appropriate quality.

## Projects

### Georgia Straight Crossing Project

- BC Hydro continued work on the Georgia Strait Crossing (GSX) Project, which will provide firm natural gas transportation to Vancouver Island to supply the existing Island Cogeneration Project and the new proposed Vancouver Island Generation Project. BC Hydro and the Williams Gas Pipeline Company (WGP) are jointly sponsoring the project. The results of the recently completed detailed WGP and BC Hydro cost review indicate a cost of $340 million, based on 90 per cent probability of non-exceedance. BC Hydro's share of this cost is expected to be $171 million. These increases are still being reviewed and have not been approved by BC Hydro. They are primarily related to increased costs for scope changes, increased regulatory/ environmental requirements, increased First Nations issues and a potential delay in the in-service date of the project from October 2004 to October 2005 due to delays in the National Energy Board (NEB) regulatory process in Canada. Regulatory applications for the project were filed with the NEB and the Federal Energy Regulatory Commission (FERC) in the United States in April 2001. The FERC process in the United States is complete and a certificate for the U.S. portion of the project was issued on September 20, 2002. The Canadian process is ongoing, and the date for a start of a public hearing is expected to be determined late in 2002. Accordingly, the public hearing will not commence until 2003.

### Vancouver Island Generation Project

- The Interim Agreement for jointly developing the project with Calpine has been terminated and, as a result, the overall project costs are now the responsibility of BC Hydro. The application to the Environmental Assessment Office (EAO) is being based on constructing the plant on land to be purchased from Pope & Talbot at the Harmac Mill Site. The application has been completed and submitted to the EAO on June 17, 2002, for review under existing legislation, although the new BCEAA Bill 38 has been passed but not put into effect. The timeline for review of the project for a Project Approval Certificate was extended by 15 days by the EAO to allow the maximum time for public comment. A further Ministerial extension was requested and granted to complete public consultation and to accommodate First Nations consultation. The public comments period was completed on October 22 and the referral period is scheduled to be completed on January 17, 2003. The environmental review will probably transfer to the new BCEAA – Bill 38, since it is expected to come into force before January 2003. The scheduled in-service date is still November 2004 but steps are being taken to limit commitments going forward until the GSX regulatory approval becomes firm. The overall capital cost for the project has been re-estimated at $370 million including an allowance for delay to a fall 2005 in-service date should GSX be delayed.

### Seven Mile Unit 4 / Dam Safety Improvements

- Manufacture of critical, large turbine parts, including the turbine runner was completed. The accelerated in-service date of March 31, 2003 remains feasible with the current multi-shift installation and commissioning program. Completion of the 210 MW generating unit is forecast to cost $92.8 million, which is $4.0 million below the approved budget. The 11-month project acceleration is forecast to generate at least $10.0 million in additional project benefits.
- The project scope to improve dam stability at Seven Mile, by use of post-tensioned anchors and provide assurance of spillway operation to current dam safety standards, is currently being reviewed to identify potential project efficiencies. The first priority dam anchoring work was awarded to Peter Kiewit Sons Ltd. for $13.0 million and construction work commenced onsite. The forecast project cost of $100.0 million was revised downwards to $87.7 million and now excludes the project scope reserve.

### Fort St. James Area Reinforcement

- The system in the Fort Saint James area is voltage limited and BCUC has mandated that BC Hydro undertake work in response to Apollo Forest Products' projected load increase. To maintain voltage within acceptable limits, an 8 MVA D-VAR system supplied by G. E. will be installed at the Fort St. James substation (FM2) at a cost of $4 million. G. E. have completed manufacturing of the D-VAR equipment and delivered it to site in late September. FM2 station modifications to accommodate the new equipment are underway. Commissioning of the new equipment is scheduled to be completed in November.

### External Work

Over the last five years, Engineering's revenue from external consulting activities with third parties (non-BC Hydro) has averaged about $2.5 million per year. Due to the shut-down of BCHIL and Engineering's re-organization, revenues fell to about $1.4 million in 2001/02 with a net margin of about $40,000. The current forecast for 2002/03 is $1.5 million revenue, with a $300,000 net margin. Current external clients include Yukon Energy Corporation, Aquila, GVRD, EPRI, and Luzon Hydro Corporation.

### Financial Performance

Key financial metrics for Engineering for fiscal 2003-Q2 are:

| Metric | FY03-Q2 | Year to Date |
|---|---|---|
| Utilization (hourly) | 82% | 78% |
| Billable hours | 206 k | 398 k |

Utilization is defined as the percentage of available hours (approx. 1600 hours per year) of all staff that has been charged to billable work (work authorized by LOB's or external clients).

## Introduction

Field Services provides all of BC Hydro's Service Restoration, Maintenance, Construction (Civil, Electrical and Mechanical), Telecommunications Maintenance, Public Safety, and Vegetation and Line Contractor Management services for Transmission and Distribution. Field Services' role is to work safely to keep the lights on while providing customers with high quality service at low cost.

## Employee and Customer Safety

Field Services' top priority for fiscal 2003 continued to be improved safety performance. A continued emphasis is being placed on having a management presence in the workplace with a focus on safety messaging and reinforcement of safe work behaviours.

Safety performance is improving. For the six month period ended September 30, 2002, Field Services had 17 fewer injuries as compared to the same period last year. This translates into the Field Services All Injury Frequency (AIF) being significantly down from 10.1 at the end of fiscal 2002 to 8.6 at the end of this second quarter.

Our delivery of public safety programs for schools and first responders continues throughout the province in an effort to reduce the risk of public incidents.

## Building a Strong and Capable Workforce

Field Services continues to move forward with building a highly skilled workforce through its continuing focus on the apprenticeship programs and effective technical and safety training programs.

Through the Strategic Workforce Planning initiative, Field Services plan to hire 32 new trade apprentice and managerial positions in fiscal 2003; this will bring the total trainees within Field Services to 94, or approximately eight per cent of the Field Services regular workforce.

Progress on the development of a pre-apprenticeship program for Power Line Technicians (PLT's) continues, in conjunction with the International Brotherhood of Electrical Workers (IBEW), the Electrical Industry Training Institute (EITI), the Line Contractors Association (LCA) and Kwantlen University College.

## Service Restoration / Customer Reliability

Field Services continues to focus on service restoration and customer reliability.

CAIDI (Customer Average Interruption Duration Index) is a measure of the average amount of time that an interrupted customer is without power during a year. Field Services is a key contributor to BC Hydro's CAIDI of 2.26 hours (excluding the severe windstorm of December 14–16, 2001), which is slightly above the BC Hydro year-end target of 2.15 hours.

Recent examples of Field Services' efforts involving service restoration and customer reliability include the following:

- A major BC Hydro industrial customer lost the use of their self-owned main substation-type transformer and was faced with this critical loss for a period of up to several months. With Field Services' involvement and cooperation, a mobile transformer was relocated to the customer site and temporary power restored within 24 hours.
- As a result of a recent failure in the Vancouver underground feeder system, Field Services participated in a cooperative BC Hydro effort to quickly relocate a spare transformer to Sperling substation and upgrade the 60 kV system. This action will mitigate a potential widespread outage should a further failure occur before repairs to the damaged feeder are completed .

### Field Services Recoveries

Field Services recoveries for the six month period ended September 30, 2002 was $119 million compared to a plan of $113 million. Recoveries reflect services provided to internal BC Hydro Lines of Business customers as well as third party customers who are external to BC Hydro. Internal recoveries account for over 98 per cent of the total recoveries. For the internal recoveries, approximately 70 per cent is derived from an internal BC Hydro workforce, with the remaining 30 per cent from Contractor workforces.

Internal workforce chargeable hours are tracking near Plan levels with 850 000 chargeable hours billed. The chargeable hours utilization (total number of chargeable hours divided by the total number of hours available) is approximately 80 per cent. Under current billing practices, management, supervisory and administrative time (this represents about 30 per cent of the total Field Services internal available hours) is not billed separately to customers but is factored into the chargeable hourly rate.

SHARED SERVICES

## Introduction

The Shared Services organization within BC Hydro provides a range of products and services that include Customer Services, Information Technology, Fleet Services, Financial Systems and Disbursement Services, Property and Office Services, Supply Chain and Human Resource Services.

## Customer Care

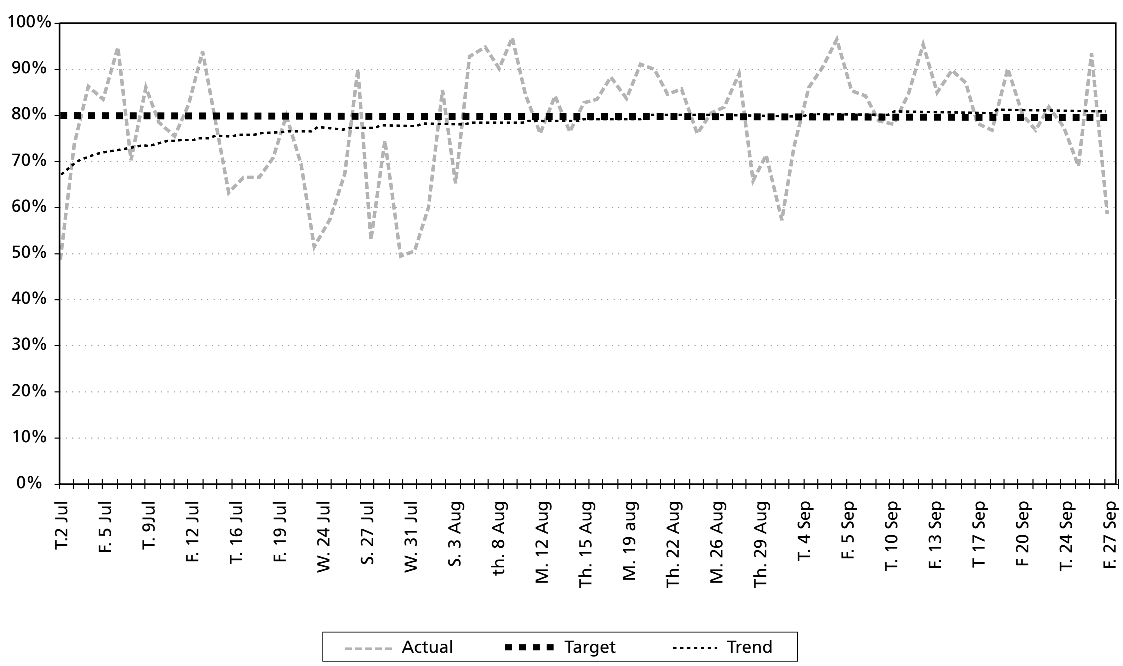
The Service Level chart shows the number of calls to the Customer Care line that were answered within 30 seconds of a caller requesting to speak to a Customer Service Representative (CSR) and exiting our Interactive Voice Response (IVR) system. The Percentage of Total Calls Abandoned shows the number of callers that hung up before being answered by a Service Representative.

### CUSTOMER CARE SERVICE LEVEL – JULY 1 TO SEPTEMBER 30, 2002

The second quarter of the current fiscal year was relatively busy, as a major software upgrade and increased call volumes challenged our resources. Total calls offered to the IVR for the second quarter of the current fiscal year were approximately 743 200, compared to 675 800 calls for the same period last year, an increase of 11 per cent (15 per cent YTD). The beginning of separate billing by BC Gas in July resulted in the increase in customer calls during July and August. Total calls answered by CSRs were over 483 400, compared to 450 400 for the same period last year, an increase of seven per cent (11 per cent YTD).

In the second quarter of the current fiscal year, the call center was only able to achieve an overall adjusted Customer Care service level of 76 per cent (77 per cent YTD), unfavourable to our target of 80 per cent.

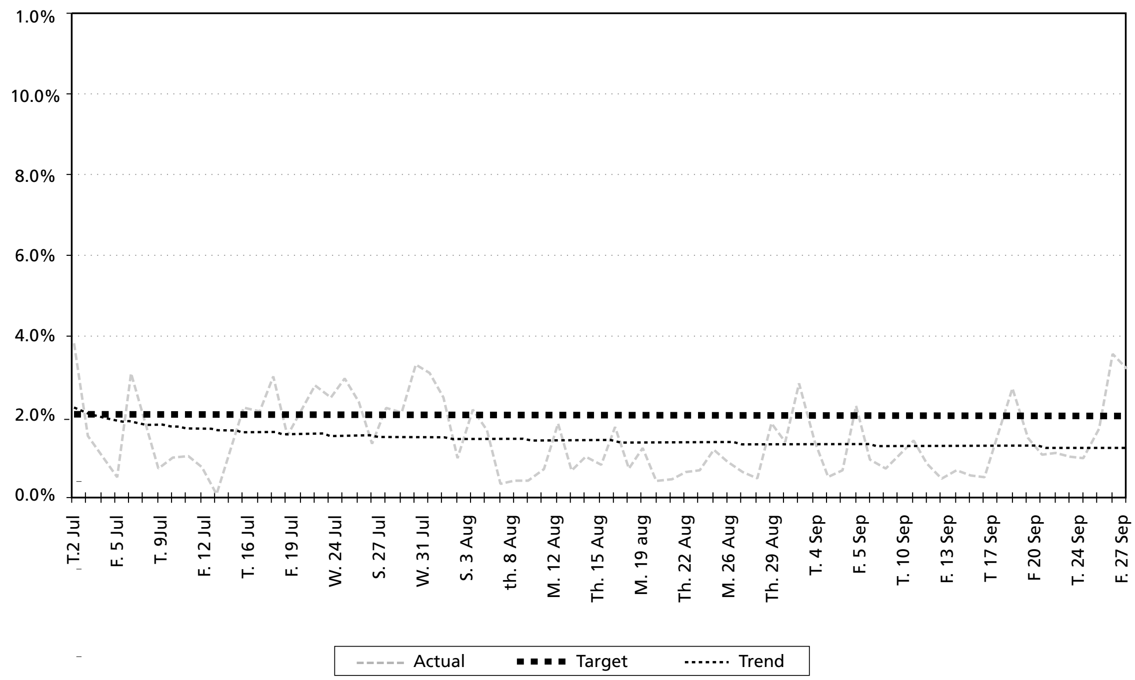
The challenge for the call centre as we move into high-bill and flu season will be to exceed our service level objective month over month to meet our annual objective.



## PERCENTAGE OF TOTAL CALLS ABANDONED – JULY 1 TO SEPTEMBER 30, 2002

Note: The increase in total calls abandoned during July and August was due to the increase in BC Gas customer calls following the change to separate BC Gas billing in July.

The adjusted abandonment rate of 1.3 per cent (1.5 per cent YTD) continues to compare favourably to our target of 2.0 per cent.




### RFEI Update – Combined Bid

Effective April 1, 2002, responsibility for project management of the RFEI - Combined Bid was transferred to the Corporate Office. Shared Services continues to act in a supporting role to the project providing information and resources as required by BC Hydro for their negotiations with Accenture. Over the second quarter, significant effort has been focused on supplying responses to the Due Diligence processes.

In July, BC Hydro and Accenture entered into a Memorandum of Understanding (MOU) to establish a new entity and develop a new service agreement with BC Hydro. The new entity will assume Hydro's Customer Services, Information Technology Services, Network Computing Services, Human Resources Services, Financial Systems, Purchasing, Disbursement Services, Property Services, and Business and Office Services.

In anticipation of creation of the new Joint Venture entity, the Shared Services group has continued planning for transition into the new organization (subject to the successful conclusion of the MOU with Accenture).

### RFEI Update – Fleet

The project team managing this process has been trying to meet its objective of establishing a MOU with one of these two finalists: Penske and Mainroad/Fleet Employees. To date, it has not been possible to come to such an agreement with either of these two proponents. As a result, BC Hydro is putting the entire Fleet process "on hold" for the time being. This initiative will be reactivated in the new year after the completion of the Combined Bid process with Accenture.

## Separation of BC Gas

Due to the removal on July 1, 2002 of the BC Gas accounts from our Customer Information System, July to September 2002 was a transition period for both BC Hydro and BC Gas employees and customers. During this time, the BC Hydro call centre received and answered more than 14 000 calls regarding the conversion.

Customer bills affected by the change were adjusted and misapplied payments were transferred to BC Gas. Customers will continue to be contacted and informed of the change of process to ensure they make their future payments to the correct company.

## Northstar Project

The Northstar project [Customer Care System (CCS) which replaces the Customer Information System] was relaunched in July after a six month break. The System Application & Product software was purchased and installed.

Also, 122 business processes were reviewed and finalized, and forms, reports and interfaces confirmed along with the "go live" date of December 2003.

Further, a prototype of the new system was developed to demonstrate what the CCS will look like and shared with employees at the Edmonds' Northstar Open House.

## Materials Management

Materials sales to September 30 have increased 20 per cent over the same period for fiscal 2002. We have achieved the sales increase, while at the same time decreasing our loading rate on material issues, from 30 per cent to 28 per cent effective July 1, 2002.

## SAFETY PERFORMANCE

We have made significant progress towards our goals of being a first quartile performer in worker and workplace safety. During the second quarter, the Continuous Improvement Safety Management System was monitored through audits conducted in several locations in the Thompson/Shuswap area (line workers) and Upper Columbia (generation workers). These audits indicated that we continue to do very well in supervision, instruction and training, and job planning, and, we also need to continue to focus on improvements in the way we manage our materials and worker exposure to hazards such as noise. Our two-year audit cycle will evaluate every BC Hydro facility once during that period. We are currently on track to meet that commitment.

Safety incidents are investigated with our "Incident Investigation Process". While these incidents vary in severity from relatively minor to very serious, it is important to ensure that we are identifying both the "immediate" and "root" cause of incidents. Of the 84 incidents we have investigated during this fiscal year, 277 corrective actions have been implemented to reduce the chance of any of these incidents happening again. There are three corrective action plans outstanding that have acceptable explanations for the delay in implementation.

We monitor our performance in a number of ways, but ultimately the goal is fewer workplace injuries. BC Hydro's All Injury Frequency (AIF, is a standard measure of both disabling and medical aid injuries per 200 000 hours worked) for the second quarter is 3.64. This continues to represent a steady improvement, which, with continued high performance, positions us to achieve our target of a ten per cent reduction in fiscal 2003.

## DEMAND SIDE MANAGEMENT

Power Smart continues implementing its comprehensive ten-year plan to reach an annual target of 3500 GW·h in new energy savings, or enough energy to supply 350 000 homes in British Columbia.

For business customers, committed and installed opportunities, plus new high potential opportunities, totalled 295 GW·h; for residential customers, annual savings are at 19 GW·h, for a total of 314 GW·h towards this year's cumulative target of annual energy savings of 360 GW·h.

Over 500 Power Smart Partner agreements are in progress with business customers and more than 180 applications for incentives have been received from business customers in response to competitive calls. Examples of customer incentive projects include:

- A lighting retrofit at the Fairmont Chateau Whistler will save the hotel 1.9 GW·h annually.
- By instituting strict energy management procedures and projects, Langley School District achieved savings of $33,000 during the school year and an additional $90,000 during the summer shutdown.

For residential customers, over three GW·h of savings were achieved through a program to replace common area lights that operate 24 hours a day in multi-family residential buildings with energy efficient compact fluorescent lightbulbs. Members of the Power Smart Youth Team provided the bulbs, as well as light emitting diode exit lights, to customers.

Power Smart launched its program for Vancouver Island on October 2nd, proclaiming Vancouver Island and the Gulf Islands the first Power Smart Region in the province. In the first week, over 30 000 compact fluorescent light bulbs were distributed to residential customers. Refrigerator buy-back and home energy use programs were also successfully launched on Vancouver Island.

## HUMAN RESOURCES

To ensure that BC Hydro will be able to sustain its core operations, a strategic workforce planning initiative is underway to renew critical workforce capability in the occupational groups that will be most impacted by retirements. From fiscal 2001 to fiscal 2003, $19 million in initiative funding has been committed to hire apprentices and trainees in trades, engineering, technical and management positions.

During the second quarter, a retirement modelling tool was developed to enhance the validity of retirement projections. During the third quarter, baseline retirement projections will be developed for key occupational groups in each line of business and service organization. Projections will be used in conjunction with resource optimization plans to forecast workforce gaps and develop a five to ten-year plan for workforce renewal.

The number of new hires by the end of the quarter was 66 regular employees. Employee attrition, which includes retirements, resignations and other terminations, was 3.4 per cent or 176 employees at the end of the second quarter. For the year-to-date, attrition exceeds new hiring by 110. Of 679 employees eligible to retire in fiscal 2003,19 per cent or 82 employees retired or were on pre-retirement at the end of the second quarter.

## REGULATORY

BC Hydro filed an application with the British Columbia Utilities Commission ("BCUC" or "Commission") on September 30, 2002 requesting a Certificate of Public Convenience and Necessity ("CPCN") to install a new underground cable circuit (2L33) from the Horne-Payne substation in Burnaby to the Cathedral Square substation in downtown Vancouver. Estimated cost of this project is $44 million. The proposed 230 kV line will replace an existing 45 year-old cable circuit which is nearing the end of its useful life. Installation of the proposed 2L33 line will be along a new route to improve system reliability and provide a seismically secure supply to the downtown core.

After the Commission declined to reconsider its decision on the complaint brought forward by the OPEIU earlier this year concerning BC Hydro's RFEI proposal, the OPEIU filed an application for leave to appeal the decision to the BC Court of Appeal. On September 30, 2002, the OPEIU notified the Court that it was withdrawing its application.

The Canadian process for reviewing the Georgia Strait Crossing (GSX) Project is ongoing with the date for the filing of evidence by intervenors set for November 28 and the process for obtaining additional information relating to this evidence to conclude on January 21, 2003. The date for the commencement of the public hearing has not been reset yet. A pre-hearing conference to narrow differences on key technical and scientific issues associated with the marine portion of the Canadian segment of the GSX project has been scheduled for November 14 and 15 in Sidney, B.C. On September 20, 2002, the Federal Energy Regulatory Commission issued its final order granting a CPCN for the US segment of the project.