Third Quarter Report

For the nine months ended December 31, 2002

BC hydro

INDEX

1. OVERVIEW

KEY HIGHLIGHTS

Financial

- Consolidated net income of $306 million for the nine months ended December 31, 2002, was $125 million higher than for the same period in the previous year. This increase occurred in the third quarter and was largely due to the impact of improved water inflows, lower interest rates, and higher electricity trade margins.
- Net income from domestic sources under the Accountability Framework (used for management reporting) for the nine months ended December 31, 2002 totalled $258 million while electricity trade sources contributed $175 million to net income. Under the Accountability Framework, energy purchases made for future resale are shown as a Trade Account on Powerex's balance sheet. Powerex's trade account has increased to $132 million (2955 GW·h) from $67 million (1967 GW·h) as at March 31, 2002. Under GAAP (Generally Accepted Accounting Principles) reporting, all energy purchases are expensed in the period of purchase.
- BC Hydro's forecast net income for fiscal 2003 is approximately $350 million, though a continuation of the dry weather experienced so far this winter could put meeting this target at risk. Based on the $350 million target, 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 $255 million to $395 million under various plausible scenarios.

Performance Plan

- BC Hydro's third quarter performance was better than expected. Seven out of the eight measures reported on either met (3) or exceeded (4) their quarterly targets.
- BC Hydro exceeded its quarterly financial goals. Net Income was better than target mainly as a result of improved water inflows that resulted in an increase in low-cost hydro generation. Also contributing to the better than targeted results were: higher residential revenues due to an increase in customer usage; 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. Additionally, 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) and a decrease in finance charges contributed to the increase in net income over target.
- 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 and there were no incidents categorized as severe. Also, the number of conservation gigawatt hours saved were greater than target due to greater than anticipated demand for Power Smart programs.

- Although significantly better than the previous quarter, 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.

Domestic Supply and Demand

- Year-to-date total billed sales were 35 300 GW·h. This is 894 GW·h or 2.6 per cent higher compared to the third quarter of the previous fiscal year. Of this total, Large Industrial sales were 210 GW·h higher; General sales were 335 GW·h higher; Residential sales were 316 GW·h higher; and Other sales were 34 GW·h higher.
- 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 8481 MW on December 18, 2002. This compares to the peak demand of 8692 on December 4, 2001.
- Precipitation in the Peace River basin during the third quarter was well below normal. The January 1, 2003 forecast for Williston Reservoir inflows during February – September 2003 is 89 per cent of normal. Columbia River/Kootenay Basin precipitation was also well below normal during the quarter. The January 1, 2003 forecast for Kinbasket Reservoir inflows during February – September 2003 is 82 per cent of normal. The forecasts for Revelstoke and Arrow local inflows are 84 per cent and 95 per cent of normal, respectively. In the Kootenay region, the January 1, 2003 runoff forecasts for Duncan Reservoir and Kootenay Lake locality are 82 per cent and 79 per cent of normal, respectively. Precipitation was also generally below normal on the South Coast and Vancouver Island during the third quarter. The January 1, 2003 forecasts for reservoir inflows in the Bridge/Coastal region are generally below normal, but range from 84 per cent of normal at Wahleach in the eastern Fraser Valley to 105 per cent of normal at Comox Reservoir on Vancouver Island. For the entire BC Hydro system, the January 1, 2003 forecast for reservoir inflows is 87.3 per cent of normal. (Note that when BC Hydro does these forecasts, it assumes "average" precipitation for the remainder of the year.)

Lines of Business

- Power Smart continues implementing its comprehensive 10-year plan to reach an annual target of 3500 GW·h in new energy savings, or enough to supply 350 000 homes in British Columbia. Power Smart savings for business and residential customers for this fiscal year to date total 375 GW·h, placing Power Smart on track to exceed this year's cumulative target of annual energy savings of 360 GW·h.
- The Power Smart Seasonal Light Emitting Diode (SLED) Program resulted in BC Hydro distributing 17 000 holiday light strings to over 60 holiday lighting display organizations across the province to demonstrate this new technology. SLEDs use more than 90 per cent less electricity than standard incandescent seasonal lights, last up to seven times longer, and cost substantially less to operate.
- BC Hydro is seeking 10 to 20-year agreements to supply new, competitively priced electricity totalling 800 GW·h/year from customer-based generation. In response to a Request for Qualifications, BC Hydro received 38 proposals from customers from all sectors across the province. 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 BC Hydro's Web site. A workshop for potential bidders was held on November 4,

2002. Bids are due to be received on 14 March 2003 and EPAs are expected to be awarded in June 2003.

- BC Hydro issued another call for green energy in October 2002 for up to 800 GW·h/year. By the deadline of 16 December 2002, a total of 70 proposed projects were submitted in response to a Request for Qualifications. These Qualification Statements are now being reviewed and a list of qualified bidders is expected to be released in March 2003. The submissions received represent a combined potential capacity of approximately 1000 MW, with a potential annual output of about 5500 GW·h per year. (One GW·h is the amount of electricity consumed by roughly 100 B.C. homes each year.)

- Work continued on the Vancouver Island Generation Project, a new high-efficiency natural gas-fired electricity generation facility to be built at Duke Point near Nanaimo, that will help meet the electricity supply needs for Vancouver Island. The application to the Environmental Assessment Office (EAO) for a Project Approval Certificate was submitted on June 17, 2002, for review under BCEAA Bill 29. The new BCEAA Bill 38 came into effect on 30 December 2002 and a Transition Order was issued for the project review to now be completed under the new act. The $370 million cost of the project is based on 90 per cent probability of non-exceedance. The scheduled in-service date is now the spring/summer of 2006. An application to BCUC for a Certificate of Public Convenience and Necessity is being prepared to comply with the Province's Energy Policy.

- 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 $340 million cost of the project is based on 90 per cent probability of non-exceedance. BC Hydro's share of this cost would be $171 million. The U.S. federal regulatory approval process for the U.S. portion of the project is complete. The Canadian process is ongoing, and a public hearing has been scheduled to commence on February 24, 2003. A decision from the NEB is anticipated in fall 2003. The in-service date of the project has been rescheduled from October 2004 to October 2005 to accommodate the anticipated Canadian regulatory process timeline.

- Net new customer additions totalled 14 794 for the first three quarters, an increase of 30.5 per cent over the same period last year. This increase is one of the largest BC Hydro has seen in many years. This upward trend is expected to continue for the remainder of the fiscal year.

- On December 12, a landslide in the vicinity of Sechelt Creek on the Sunshine Coast of BC buried a 500 kV tower on circuit 5L32 and forced the line out of service. In addition, two towers were destroyed, four towers were damaged and approximately 1.6 circuit kilometres of conductor were destroyed. Crews were dispatched immediately and have worked continuously to complete repairs. Repairs are expected to be completed by January 21, 2003.

- Circuit 5L32 is one of the two 500 kV circuits supplying Vancouver Island. The second circuit (5L30), which carries the load while repairs are made to 5L32, also suffered a weather-related incident on December 26. Severe icing resulted in a power outage for approximately 300 000 people on portions of Vancouver Island and the Sunshine Coast. Power was restored to the majority of customers within 90 minutes.

- During the quarter, John Icke was named president of the new joint venture entity – Accenture Business Services of British Columbia (ABS). BC Hydro and Accenture agreed on a transfer date of April 1, 2003 for employees who transfer to ABS. As part of BC Hydro's Employee Transition Options plan, elections were held in December to allow eligible employees to vote on whether to move to the new company. More than 90 per cent of the Office and Professional International Union (OPEIU) employees have chosen to move to ABS, which is similar to the number of Management and Professional employees.

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 nine months ended December 31, 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 $306 million for the nine months ended December 31, 2002, was $125 million higher than for the same period in the previous year with the third quarter of this year being $148 million higher. The increase in income was largely due to the impact of improved water inflows, lower interest rates and higher electricity trade margins during this quarter. A decrease in electricity trade margins during the first half of this year, due primarily to the substantial decline in market prices experienced since June 2001, partially offset the favourable variance.

Domestic Revenues

Total domestic revenues of $1,794 million for the nine months ended December 31, 2002, increased by $19 million from the same period last year. The increase was largely due to customer growth in the residential and light industrial and commercial sectors as more than 18 000 customers have been added to the system over the last 12 months. A significant increase in large industrial revenues during the third quarter of this year compared to the same period in the prior year also contributed to the increase in domestic revenues. Large industrial revenues during the third quarter of the prior year were unusually low due to several factors including the decline in the economy shortly after the events of September 11, 2001. These increases were partly offset by the decrease in miscellaneous revenues during the first half of the year. Miscellaneous revenues declined primarily due to a decrease in ancillary service revenues as a result of lower market prices for such products as energy loss compensation for transmission.

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 nine months ended December 31, 2002, were $1,504 million, a significant decrease of $2,084 million from the same period last year. The decrease was primarily due to a reduction in average sale prices which fell by 71 per cent from $215/MW·h last year to $62/MW·h this year. Market prices have declined to more traditional levels since June 2001. A 46 per cent increase in sales volumes from 16 722 GW·h in the prior year to 24 438 GW·h this year partly offset the decrease in sale prices. This increase in sales volumes was largely due to greater market opportunities for buy/resell transactions.

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

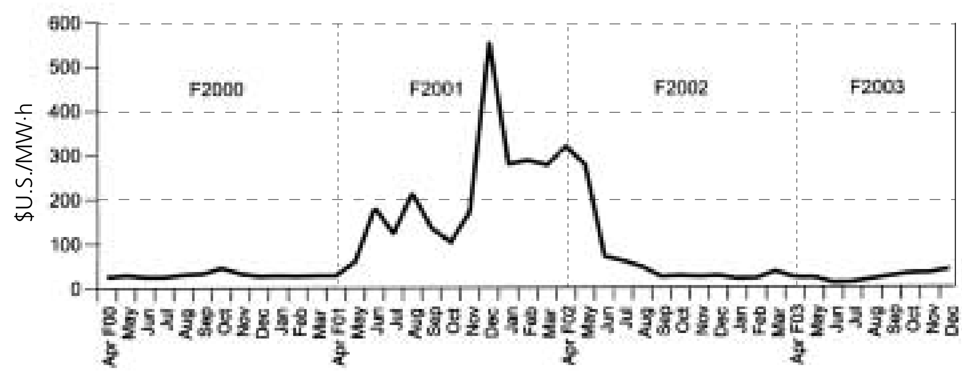
	(in millions)		Volumes (in GW·h)		Average Prices ($MW·h)	
1st Quarter (April-June)	**2002**	2001	**2002**	2001	**2002**	2001
Sales	**$358**	$1,860	**6,995**	4,940	**$51**	$377
Purchases[1]	**342**	1,608	**9,614**	7,665	**36**	210
Net Import			**(2,619)**	(2,725)		
2nd Quarter (July – September)						
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)		
3rd Quarter (November – December)						
Sales	**$489**	$481	**7,118**	5,528	**$69**	$87
Purchases[1]	**361**	458	**6,263**	5,459	**58**	84
Net Export			**855**	69		
Total						
Sales	**$1,504**	$3,588	**24,438**	16,722	**$62**	$215
Purchases[1]	**1,199**	3,128	**25,225**	21,211	**47**	147
Net Import			**(787)**	(4,489)		

[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 nine months ended December 31, 2002. The 787 GW·h of net imports purchased during the first nine months 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 855 GW·h in the third 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 $1,825 million for the nine months ended December 31, 2002, decreased by $2,118 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. A decrease in electricity trade transmission costs due to lower market prices also contributed to the decrease in energy costs while an increase in purchases used for buy/resell transactions in the electricity trade market partly offset the favourable variance.

Energy purchase prices averaged $47/MW·h for the nine months ended December 31, 2002, compared to $147/MW·h for the same period last year, a 68 per cent decrease. A significant portion of this decrease occurred during the first half of the year.

Water inflows into BC Hydro's reservoirs for the first nine months of this year increased by 19 per cent over the prior year, allowing for an increase in low-cost hydro generation of more than 6500 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 December 31, 2002 was at average levels with the Williston Reservoir on the Peace River system at 110 per cent of average and the Kinbasket Reservoir on the Columbia river system at 75 per cent of average. This compares to the combined storage at December 31, 2001 of 95 per cent of average with the Williston Reservoir at 108 per cent of average and the Kinbasket Reservoir at 64 per cent of average.

Operations, maintenance and administration (OMA) expenses of $387 million for the nine months ended December 31, 2002, decreased by $16 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, the shift of work from OMA to capital in nature due to an increased focus on sustaining capital and to targeted cost reductions. These decreases were partly offset by an increase of approximately $10 million in legal and other associated costs related 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 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. An increase of approximately $30 million in employee future benefit costs based on an actuarial valuation of the BC Hydro pension plans which reflected increased obligations due to employees retiring earlier and living longer, and a decline in the value of the pension fund assets due to the decline in stock markets also partly offset the decreases in OMA.

Taxes

Taxes, which are comprised of school taxes, grants in lieu of taxes and the corporation capital tax, decreased by $19 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 $302 million for the nine months ended December 31, 2002 increased by $19 million from the same period last year. This increase was primarily due to more assets in service.

Finance Charges

Finance charges of $367 million decreased by $56 million from the same period last year primarily due to lower short-term interest rates. Interest rates on Canadian variable rate debt declined by 35 per cent to an average of 2.6 per cent for the first nine months of this year compared to 4.0 per cent for the same period in the prior year.

Investing Activities

Capital expenditures, including demand-side management programs, for the nine months ended December 31, 2002 amounted to $533 million compared with $364 million for the same period last year.

(millions of dollars)	2002	2001	Change Increase (Decrease)
Generation replacements and expansion	$175	$87	$88
Transmission lines and substations replacements and expansion	117	60	57
Distribution improvements and expansion	121	110	11
General–computers, vehicles, etc.	92	104	(12)
Power Smart (Demand-side management)	28	3	25
Total	$533	$364	$169

Sustaining capital expenditures on existing assets amounted to approximately $253 million while expenditures for growth totalled approximately $280 million for the nine months ended December 31, 2002.

The increase in generation related expenditures was primarily due to expenditures for the Vancouver Island Generation Project (VIGP), a new high-efficiency natural gas-fired electricity generation facility proposed to be built at Duke Point near Nanaimo. Expenditures for the nine months ended December 31, 2002 totalled approximately $48 million and related to the payments towards the purchase of a gas turbine and steam turbine. BC Hydro is deferring its application to the BC Utilities Commission for a Certificate of Public Convenience and Necessity for the proposed VIGP in order to investigate private sector alternatives to address Vancouver Island's looming electricity shortfall. The timing of VIGP could be deferred past the fall 2005 in-service date depending on the results of this investigation.

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 nine months ended December 31, 2002 totalled approximately $31 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 nine months ended December 31, 2002 totalled approximately $10 million and related to the purchase and installation of fibre optic cables and ancillary equipment. 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 nine months ended December 31, 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. These installations have been completed and are ready for the IPP to deliver power.

BC Hydro's Power Smart energy efficiency program expenditures for the nine months ended December 31, 2002 totalled approximately $28 million. Current year activities emphasize incentive–based programs for business customers throughout the Province and residential customers on Vancouver Island.

Financing Activities

During the nine months ended December 31, 2002, BC Hydro issued three Canadian and two U.S. bonds totalling Cdn $1,007 million. The proceeds from these issues were primarily used to redeem U.S. bonds totalling Cdn $579 million and to fund capital expenditures and the payment to the Province.

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.
- External revenues relating to BC Hydro's fleet services are recorded in Field Services, which is shown as part of 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 pages 39 to 59.

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 December 31, 2002. As this is the first year of operating under this "Lines of Business" structure, there is no comparative information for the prior year.

Nine months ended December 31, 2002

(millions of dollars)

	Distribution	Transmission	Generation	Powerex	Other[3]	Consolidation Adjustments/ Eliminations	Total
External revenues	1,720	7	42	1,559	31	(61)[2]	3,298
Inter-segment revenues	–	595	943	46	406	(1,990)	–
Net income (loss)	47	220	140	175	(149)	(127)[2]	306
Total assets	2,905	2,828	4,391	493	724[1]	(344)	10,997

Three months ended December 31, 2002

(millions of dollars)

	Distribution	Transmission	Generation	Powerex	Other[3]	Consolidation Adjustments/ Eliminations	Total
External revenues	640	2	19	530	10	(43)[2]	1,158
Inter-segment revenues	–	203	360	16	122	(701)	–
Net income (loss)	49	75	95	67	(64)	(57)[2]	165

1. Mainly consists of capital assets such as office buildings, vehicles, computer equipment and deferred Demand-side Management Programs.
2. 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.
3. Includes Engineering Services, Field Services and Shared Services Organizations, other subsidiaries including Westech and Powertech and Corporate costs. The Service Organizations charge the cost of their services to the Lines of Business and Powerex.

The following table shows the composition of the Other column for the nine months ended December 31, 2002:

	Field Services	Engineering Services	Shared[1] Services	Powertech	Corporate	Total Other
External revenues	5	–	16	10	–	31
Inter-segment revenues	159	56	178	3	10	406
Net income (loss)	1	1	4	2	(157)	(149)
Total assets	50	14	77	7	576	724

1 Includes Westech

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, the same as forecast in BC Hydro's Service Plan of January 2002. Several factors, including the continuation of dry weather being experienced this fall and winter, could put meeting this target at risk. BC Hydro may increase purchases for the remainder of fiscal 2003, if economic, to help mitigate the impact of low snowpack levels on fiscal 2004 income. 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 $255 million and $395 million.

The fall and early winter of this year have been extremely dry resulting in below normal snowpack levels and correspondingly low projected water inflow levels for the next fiscal year. System inflows, based on the January 1, 2003 snowpack levels, are projected to be 87 per cent of normal for next year. This is expected to have a significant negative impact on fiscal 2004 results as system inflows are expected to be reduced by as much as 6500 GW·h from normal, resulting in a reduction in the availability of low-cost hydro generation. Domestic load will still be met but at a higher cost to BC Hydro. The reduction in inflows will also put pressure on reservoir levels as BC Hydro is anticipating that it will test the historic minimum levels for the Williston and Kinbasket reservoirs.

In November of 2002 the Provincial Government released its Energy Plan for BC. This Plan, among other objectives, calls for BC Hydro's Transmission Line of Business to become a separate publicly owned company. The Energy Plan also calls for an end to the current rate freeze at the end of March 31, 2003 and a Revenue Requirement Hearing by the end of 2003/04 to determine if changes are required to current tariff rates. These changes could have significant impacts to BC Hydro's financial position.

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 $7 million for the nine months ended December 31,2002.

Legal Contingency

A discussion of claims against Powerex is included in the notes to the March 31, 2002 financial statements in the 2002 Annual Report and the legal contingency section in the September 30, 2002 Interim Report. Since this date, some key decisions have been made in the California electricity consumer class action lawsuits, which have alleged that the California wholesale markets were unlawfully manipulated and that the energy prices were excessive. On December 13, 2002, the Federal Court concluded that BC Hydro is immune from liability related to this action. The Court has not yet formally ruled on BC Hydro's dismissal application, but with these findings this is expected to follow in due course. In the same Order, the Court granted the Plaintiffs' application to have the case against the remaining defendants remanded back to California State Court. However, parties on both sides of these issues, including Powerex, have appealed the Court's decision, in whole or in part. Unless expedited, these appeals will likely not be decided prior to the end of 2003.

During December 2002, two additional class action cases were commenced, one in Oregon and the other in Washington State. Both cases name Powerex as one of a number of Defendants. Neither case names BC Hydro. The suits allege that, among other things, the Defendants manipulated wholesale energy markets resulting in supply shortages and skyrocketing energy prices across the western U.S., including Washington and Oregon. While these actions have been filed, Powerex has not yet been formally served.

Another key decision was issued by the Federal Court which will have a bearing on all outstanding class action lawsuits. This decision was made on January 6, 2003 in the case commenced by Public Utility District No. 1 of Snohomish County, and dismissed the action in its entirety on the basis of the filed rate doctrine and federal pre-emption. This decision will almost certainly be appealed by the Plaintiffs.

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 will continue to defend themselves 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.

Subsequent Event

On January 17, 2003, the arbitrator ruled in favour of Powerex in its contractual dispute with Alcan Inc. This dispute related to a long-term purchase agreement, signed in 1990, whereby Alcan would deliver power to BC Hydro for 20 years beginning in January 1995. In a November 1997 agreement referred to as the Consent Agreement, BC Hydro consented to having a portion of Alcan's electricity delivery obligations transferred to Enron Power Marketing, Inc (EPMI), a subsidiary of Enron Corp. At the same time, BC Hydro assigned its purchase rights to Powerex. Under the Consent Agreement, Alcan agreed to remain liable to Powerex for all of EPMI's' payment obligations up to U.S.$100 million. With the bankruptcy of EPMI, the power supply agreement terminated, giving rise to a termination payment due by EPMI, which it did not pay. Accordingly, Powerex sought payment from Alcan pursuant to Alcan's obligation under the Consent Agreement. Alcan failed to pay, requiring Powerex to bring the matter to arbitration. The arbitrator found Alcan liable to the full extent of the U.S.$100 million cap. The decision is final and binding. Due to the uncertainty around how and when Alcan will pay Powerex, or whether they will attempt to set the arbitrators' ruling aside in some manner, BC Hydro has not currently recognized this amount in its consolidated financial statements.

CONSOLIDATED STATEMENT OF OPERATIONS *(UNAUDITED)*

for the three months ended December 31 (in millions)	**2002**	2001		
for the nine months ended December 31 (in millions)			**2002**	2001
Revenues				
Residential	**$ 267**	$ 266	**$ 648**	$ 638
Light industrial and commercial	**230**	226	**660**	649
Large industrial	**133**	117	**384**	366
Other energy sales	**25**	24	**60**	61
Miscellaneous	**14**	16	**42**	61
	669	649	**1,794**	1,775
Electricity trade	**489**	481	**1,504**	3,588
	1,158	1,130	**3,298**	5,363
Expenses				
Energy costs	**597**	695	**1,825**	3,943
Operations and administration	**64**	n/a	**198**	n/a
Maintenance	**71**	n/a	**189**	n/a
Total Operations, Administration & Maintenance	**135**	140	**387**	403
Taxes	**37**	43	**111**	130
Depreciation and amortization	**101**	95	**302**	283
	870	973	**2,625**	4,759
Income Before Finance Charges	**288**	157	**673**	604
Finance charges	**123**	140	**367**	423
Net Income	**$ 165**	$ 17	**$ 306**	$ 181

CONSOLIDATED STATEMENT OF RETAINED EARNINGS *(UNAUDITED)*

for the nine months ended December 31 (in millions)	**2002**	2001
Retained earnings, beginning of year	**$ 1,529**	$ 1,459
Net income	**306**	181
Payment to the Province	**(184)**	(144)
	$ 1,651	$ 1,496

CONSOLIDATED BALANCE SHEET *(UNAUDITED)*

(in millions)	**as at Dec 31 2002**	as at Mar 31 2002
ASSETS		
Capital Assets		
Capital assets in service	**$14,894**	$14,608
Less accumulated depreciation	**5,811**	5,557
	9,083	9,051
Unfinished construction	**622**	459
	9,705	9,510
Current Assets		
Temporary investments	**150**	17
Accounts receivable and accrued revenue	**383**	409
Materials and supplies	**90**	88
Prepaid expenses	**18**	111
Unrealized gains on mark-to-market transactions	**10**	19
	651	644
Other Assets and Deferred Charges		
Sinking funds	**1,097**	1,073
Demand-side management programs	**112**	103
Deferred debt costs	**509**	587
Foreign currency contracts	**30**	32
Loan receivable	**20**	17
	1,768	1,812
	$12,124	$11,966
LIABILITIES AND EQUITY		
Long-Term Debt		
Long-term debt net of sinking funds	**$ 7,194**	$ 6,906
Sinking funds presented as assets	**1,097**	1,073
	8,291	7,979
Foreign Currency Contracts	**5**	16
Current Liabilities		
Accounts payable and accrued liabilities	**511**	708
Accrued interest	**140**	107
Accrued Payment to the Province	**184**	333
Unrealized losses on mark-to-market transactions	**10**	17
	845	1,165
Deferred Credits and Other Liabilities		
Provision for future removal and site restoration costs	**166**	159
Deferred revenue	**265**	238
Rate stabilization account	**88**	87
Contributions arising from the Columbia River Treaty	**205**	212
Contributions in aid of construction	**608**	581
	1,332	1,277
Retained Earnings	**1,651**	1,529
	$12,124	$11,966

CONSOLIDATED STATEMENT OF CASH FLOWS *(UNAUDITED)*

for the three months ended December 31 (in millions)	**2002**	2001		
for the nine months ended December 31 (in millions)			**2002**	2001
Operating Activities				
Net income	**$ 165**	$ 17	**$ 306**	$ 181
Adjustments for:				
– Depreciation and amortization	**101**	95	**302**	283
– Other non-cash items	**30**	36	**26**	31
	296	148	**634**	495
Working capital changes	**70**	(120)	**(23)**	(560)
Cash provided by (used for) operating activities	**366**	28	**611**	(65)
Investing Activities				
Loan receivable	–	–	**(5)**	22
Capital asset expenditures	**(170)**	(132)	**(528)**	(411)
Contributions in aid of construction	**18**	16	**52**	48
Demand side management programs	**(9)**	(3)	**(28)**	(3)
Future removal and site restoration costs	**(4)**	(1)	**(9)**	(4)
Proceeds from property sales	–	–	**1**	1
Cash used for investing activities	**(165)**	(120)	**(517)**	(347)
Financing Activities				
Bonds, notes and debentures:				
– Issued	–	200	**1,007**	200
– Retired	–	–	**(579)**	(104)
Revolving borrowings	**(166)**	96	**(94)**	181
Sinking fund changes	**(8)**	(8)	**13**	38
Premium, discount and issue costs	–	8	**3**	8
Settlements of financial instruments	–	–	**22**	–
Cash provided by (used for) financing activities	**(174)**	296	**372**	323
Payment to the Province	–	–	**(333)**	(372)
Increase (Decrease) in Cash	**27**	204	**133**	(461)
Cash at Beginning of Period (Note 1)	**123**	21	**17**	686
Cash at End of Period (Note 1)	**$ 150**	$ 225	**$ 150**	$ 225
Supplemental disclosure of cash flow information				
– Interest paid	**$ 113**	$ 99	**$ 376**	$ 403

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

OPERATING HIGHLIGHTS *(UNAUDITED)*

for the three months ended December 31 (in GW·h)	**2002**	2001		
for the nine months ended December 31 (in GW·h)			**2002**	2001
Electricity Sold				
Residential	**4,390**	4,385	**10,483**	10,343
Light industrial and commercial	**4,337**	4,266	**12,424**	12,203
Large industrial	**3,893**	3,536	**11,255**	11,028
Other energy sales	**527**	484	**1,118**	1,110
	13,147	12,671	**35,280**	34,684
Electricity trade	**7,118**	5,528	**24,438**	16,722
	20,265	18,199	**59,718**	51,406
Number of domestic customers			**1,624,555**	1,606,456
Number of employees			**5,943**	6,154

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

Bob Elton
Executive Vice-President, Finance and
Chief Financial 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. BC Hydro's goal is to be a first quartile performer in each of these areas. 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, 222 Strategic Workforce positions have been filled. By the end of the year, this total is expected to be 224.

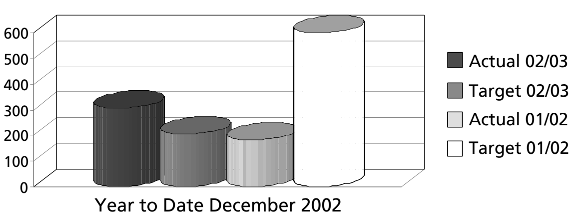
Performance Measures, Targets, and Results

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 third quarter fiscal 2003 performance measures against current targets and, where available, historical performance.

Net Income (in millions)

	Actual	Target
Q3 02/03	$306	$204
Q3 01/02	$181	$605



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 improved water inflows that resulted in an increase in low-cost hydro generation. Also contributing to the better than targeted results were: higher residential revenues due to an increase in customer usage; 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. Additionally, 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) and a decrease in finance charges contributed to the increase in net income over target.

Net Income is projected to be on target by year-end although a continuation of the dry weather experienced to date may put meeting this target at risk. The higher year-to-date income is expected to be offset by restructuring costs related to the proposed outsourcing of Support Services to Accenture. These one-time costs will be recovered through future cost savings. Also, pension costs are expected to increase as a result of a recent actuarial valuation. Increased electricity purchases, due to low snowpack levels, will also increase costs in the last quarter. Electricity purchases may increase over forecasted levels if there are economic opportunities. An increase in 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 are also expected to offset the current positive outcome.

Net income for the quarter was higher than for the same period in the previous year. A decrease in the cost of energy, due mainly to the impact of improved water conditions, and lower interest rates were the primary reasons for the favourable variance.

Total OMA Cost (in millions)

	Actual	Target
Q3 02/03		
Operations, Administration	$198	$195
Maintenance	189	190
Total	$387	$385
Q3 01/02	$403	$403

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 higher than target mainly due to an increase in pension costs as a result of a recent actuarial valuation and an increase in legal and other costs relating to the California situation (described in the Net Income measure explanation). These increases were partially offset by one-time expenditures in the prior year and targeted cost savings. Maintenance spending is on track.

Cost per Customer Transaction (in millions)

	Actual	Target
Consolidated		
Q3 02/03	$ 50.1	$ 49.6
Q3 01/02	$100.8	$158.2
Domestic		
Q3 02/03	$ 44.7	$ 47.2

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 energy costs and finance charges) whereas domestic sales volume is greater than target (primarily due to an increase in demand). The combination of these factors led to domestic Cost per Customer Transaction coming in better than target.

Reliability

	Actual	Target
ASAI		
Q3 02/03	99.967%	99.970%
Q3 01/02	99.959%	99.973%
CAIDI		
Q3 02/03	2.34 Hrs	2.15 Hrs
Q3 01/02	2.38 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. For the current results, this period was January 1, 2002 to December 31, 2002.

CAIDI, while significantly better than the previous quarter, was still worse than target mainly due to three major weather events. On April 14, 2002 a windstorm hit the Lower Mainland and parts of Vancouver Island that accounted for 7.5 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. On December 15, 2002 another windstorm struck the Lower Mainland and Vancouver Island. Winds of up to 87 km/hour were recorded along the coast, leaving thousands of homes on Vancouver

Island and the Lower Mainland in the dark for at least a few hours. The storm accounted for 8.2 per cent of the total customer-hours lost during this period. On December 25–26, 2002, another windstorm knocked down trees and power lines in the Lower Mainland, cutting electricity to parts of the area for much of Christmas Day. On Dec 26, nearly all of Vancouver Island was without power for about an hour after an accumulation of ice at a substation at Malaspina Harbour on Pender Island caused one of two 500 kV circuits that carry electricity from the Mainland to sag into trees, knocking out the power. The two-day storm accounted for 5.0 per cent of the total customer-hours lost during this period.

The main reason CAIDI was significantly better than the previous quarter is that the December 14–16, 2001 storm that accounted for about 35 per cent of the total customer-hours lost in previous periods, dropped out of the index.

ASAI, also measured on a rolling 12-month basis, was on target. This means that over the 12-month period, the system was unavailable less than a total of three hours.

Regulatory Compliance

	Actual	Target
Q3 02/03	6 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. There were no incidents in the third quarter that were categorized as severe.

Incremental Green Gigawatt Hours

	Actual	Target
Q3 02/03	0 GW·h	0 GW·h

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 fiscal 2003/04.

A call of Request for Qualifications took place on October 30, 2002. BC Hydro received 70 green power project submissions from independent power producers in response. The 70 proposals received represent a combined potential capacity of approximately 1000 megawatts, with the potential output of about 5500 gigawatt hours per year. BC Hydro plans to acquire up to 800 gigawatt hours. While more than two-thirds of the proposals are for hydroelectric projects, proposals were also received for projects involving biogas, biomass, wind, ocean wave and other energy sources. Qualifications are currently being 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
Q3 02/03	162 GW·h	140 GW·h

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.

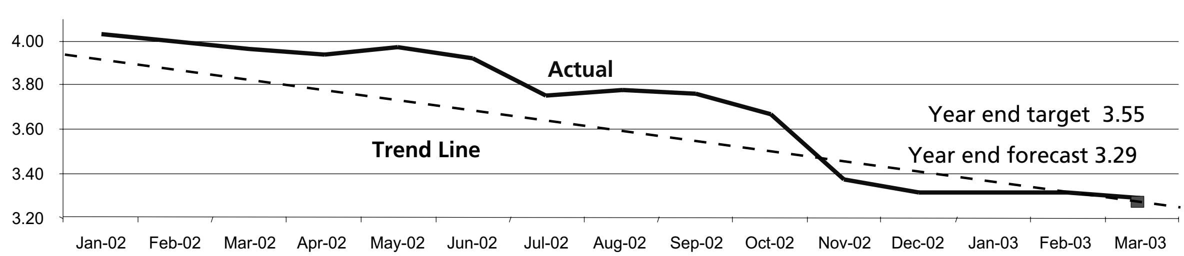
Greater than anticipated demand for Power Smart programs was the main reason that the result exceeded the target. Power Smart is organized around two customer segments – business and residential. Business programs include: Power Smart Partner, e.Points, Customer Based Generation, Revolving Fund, Sector Specific Programs, Product Based Programs, Trade Alliances, Legislation, and Regulations & Standards. Residential programs include: Vancouver Island Roll Out of Compact Fluorescent Light, Refrigerator Buy-Back and Home Energy Use, Seasonal LEDs, Web Based Tools, Awareness, and Retail Partnering.

Improvement in All Injury Frequency

	Actual	Target
Q3 02/03	15.7%	7.6%

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 efforts by all BC Hydro employees. BC Hydro’s Field Services organization had only two reportable incidents in November and led the way in the third quarter reduction of incident levels. Both medical aid and disabling injuries were reduced during this period. If the downward trend continues as expected, BC Hydro will finish the year very close to the first quartile when compared to a regional / provincial composite of Canadian utilities.



ELECTRICITY LOAD

BC Hydro System

Energy Sales

Year-to-date total billed sales were 35 300 GW·h. This is 894 GW·h or 2.6 per cent higher compared to the third quarter of the previous fiscal year. Of this total, Large Industrial sales were 210 GW·h higher, General sales were 335 GW·h higher, Residential sales were 316 GW·h higher, and Other sales were 34 GW·h higher.

The recovery in Large Industrial sales that began in the second quarter continued in the third quarter. The increase in General sales reflects the gain in sales to BC's Forestry and Services sectors. Residential sales were higher due to cool temperatures in the spring months.

On a 12-month basis, Total billed sales were 593 GW·h higher to the end of December. Of the total, Large Industrial sales were 284 GW·h lower, General sales were 330 GW·h higher, Residential sales were 515 GW·h higher, and Other sales were 32 GW·h higher.

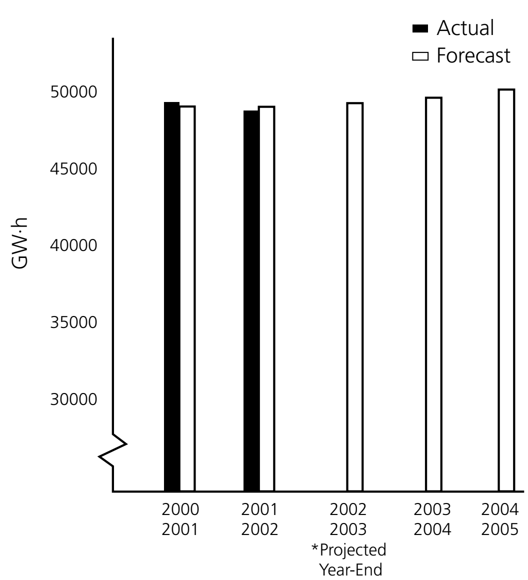
Peak Demand

Peak demand for this winter was forecast to be 9126 MW for the domestic integrated system, assuming a design temperature of –6.8°C. The design temperature is the average coldest day in Vancouver over the last 30 years.

BC Hydro is a winter peaking utility because of residential electric space heating. The domestic integrated system peak so far this winter was 8481 MW, which occurred at a daily average temperature of +5.3°C on December 18, 2002. This compares to the peak demand of 8692 MW last winter, which occurred at a daily average temperature of +2.2°C on December 4, 2001.

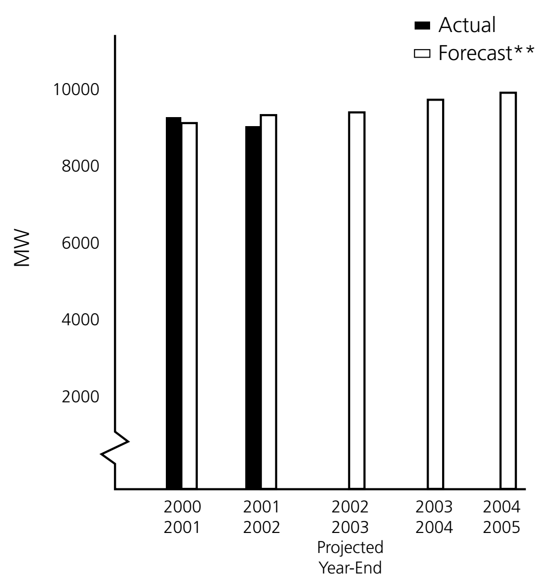
Domestic system peak demand was unusually high in the fourth week of October. The rapid rise was essentially due to winter-like temperatures of that week plus higher lighting load from the switch to Pacific Standard Time on October 27. Peak demand on the system has since returned to the normal levels for this time of the year, and peak demand, once adjusted for differences in temperature, continues to track the Peak Forecast for the current winter.

BC HYDRO SYSTEM–BILLED SALES



* Third quarter Projected Year-end includes actual sales from April 2002 to December 2002 plus projected sales for January 2003 to March 2003.

BC HYDRO SYSTEM–PEAK DEMAND*



* The peak demand is based on the revised peak forecast produced in November 2002.
** Forecast BCH System peak is based on a design daily average temperature of -6.8°C.

Short-Term Forecast

Variances in year-end sales are expected to be 2.7 per cent higher than plan. Consumer spending remains healthy in the U.S. despite much economic uncertainty, resulting in demand for BC's resource-based commodities and higher electricity sales to BC's large industrial customers. Industrial electricity sales are also projected to increase due to the startup of a new sour gas processing plant near Chetwynd, and the restart of the Tembec pulp mill under new ownership. Temperatures were warmer than normal so far this winter due to the El Nino effect. A continuation of mild winter temperatures would narrow the variance in Residential sales in the fourth quarter.

Vancouver Island (VI)

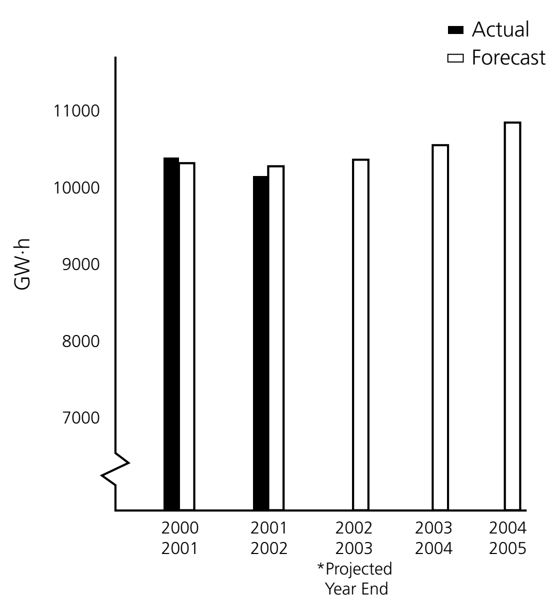
Energy Sales

Year-to-date total billed sales for Vancouver Island were 7459 GW·h. This is 275 GW·h or 3.8 per cent higher compared to the third quarter of the previous fiscal year. Large Industrial sales were 181 GW·h higher, General sales were 48 GW·h higher, and Residential sales were 46 GW·h higher. Other sales were the same.

The recovery in sales to VI's Pulp and Paper customers that began in the second quarter continued in the third quarter. The increase in General sales reflects the gain in sales to VI's Forestry, Services and Trade sectors. Residential sales were higher due to cool temperatures in the spring months.

On a 12-month basis, Total VI billed sales were 129 GW·h higher to the end of December. Of the total, Large Industrial sales were 18 GW·h lower, General sales were 60 GW·h higher, and Residential sales were 87 GW·h higher. Other sales were the same.

VANCOUVER ISLAND–BILLED SALES



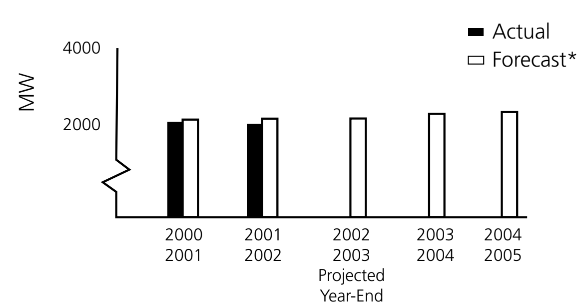
* Third quarter Projected Year-end includes actual sales from April 2002 to December 2002 plus projected sales for January 2003 to March 2003.

Peak Demand

Peak demand for this winter was forecast to be 2158 MW for the VI system, including the Gulf Islands load, assuming a design temperature of -4.4°C. The design temperature is the average coldest day in Victoria over the last 30 years.

Electricity is the primary heating source of about 40 per cent of residential customers on VI. Peak demand on VI including the Gulf Islands so far this winter was 1918 MW, which occurred at a daily average temperature of +1.9°C on December 29, 2002. This compares to the peak demand of 2005 MW last winter, which occurred at a daily average temperature of +3.8°C on December 17, 2001.

VANCOUVER ISLAND–PEAK DEMAND*



* The peak demand is based on the revised peak forecast produced in November 2002.
** Forecast BCH System peak is based on a design daily average temperature of -6.8°C.

Short-Term Forecast

Variances in VI year-end sales are expected to be 1.9 per cent higher than plan. Dominant industries on VI are all related to the forestry sector. The turnaround in Large Industrial sales since the second quarter reflects steady improvement in the demand for pulp and paper. A continuation of the trend would result in higher Large Industrial sales. The number of Residential accounts on VI was originally forecast to grow by 3232 in fiscal 2003. Residential VI account growth has been revised to 3295. The variance in Residential sales reflects the revised Residential account addition. Otherwise, the continuation of mild winter temperatures will also narrow the variance in Residential sales on VI in the fourth quarter.

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 are usually 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 the supply and demand for electricity. 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 expected conservation; 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 Market

In the first half of 2002, prices for both electricity and natural gas continued their steep decline from the record highs of 2001. Starting in August, prices have staged a significant recovery.

Among the reasons for the price decline from 2001 were:

- the U.S. recession (reducing demand for natural gas and electricity);
- significant new generating supply and natural gas wells went into service;
- relatively high gas storage inventories (compared to 2001 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. The price recovery in the later half of 2002 has been driven by:

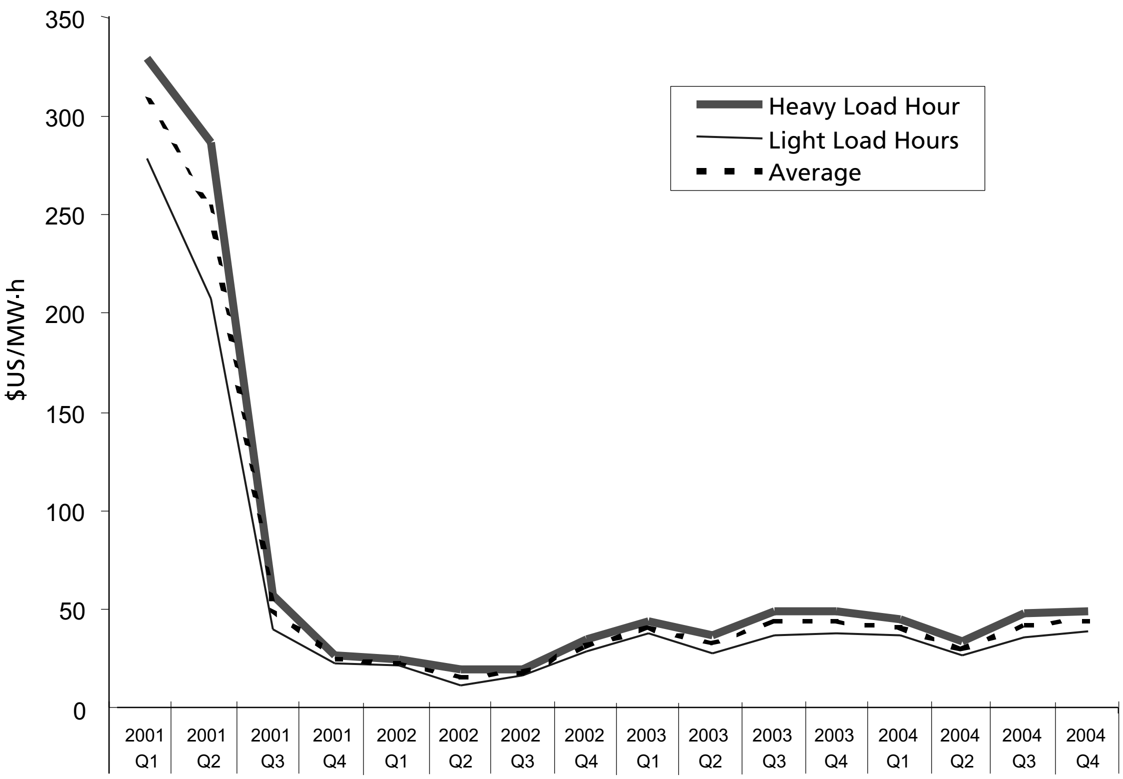
- a sharp decline in gas storage inventories from near record highs to below the five year average;
- a significant reduction in gas exploration, drilling activity and production;
- a slowdown in the introduction of new electric generation capacity; and
- increased weather related demand.

2003 Outlook

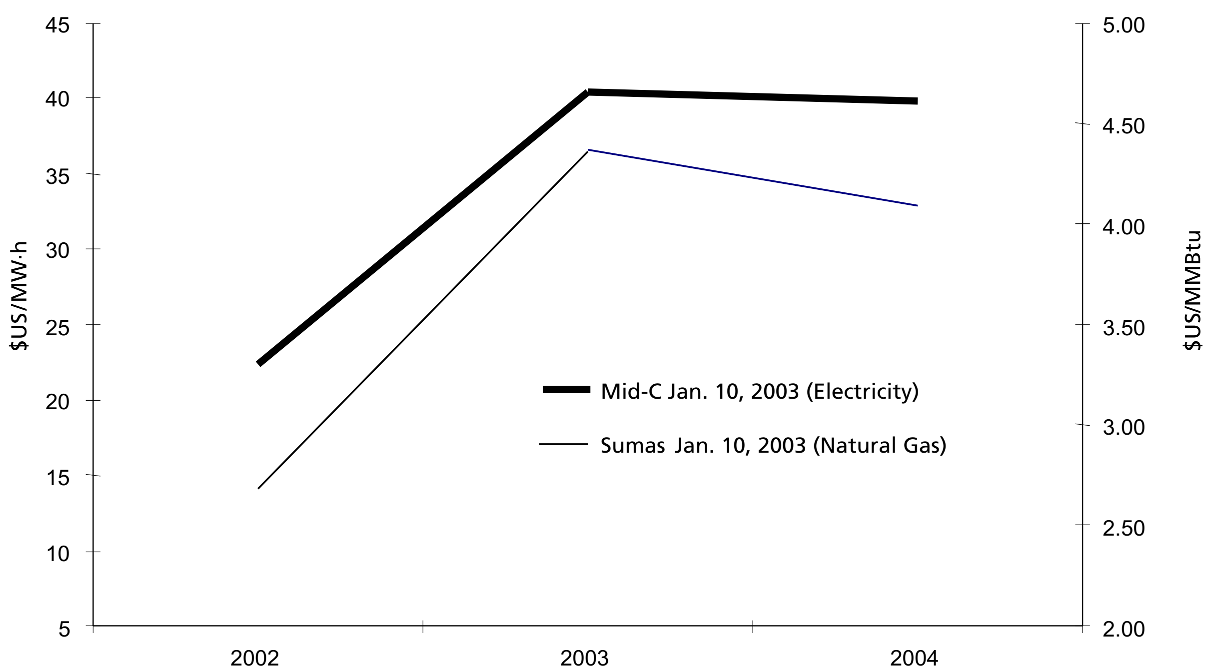
The economic outlook remains uncertain, clouded by recent stock market declines and prospects of war. Most observers continue to forecast positive economic growth in 2003, although at a slower pace. Exploration and drilling activity is expected to remain slow until late 2003. Replenishing storage reserves in the 2003 injection season is likely to be difficult. If demand holds up, prospects are for a tight supply-demand balance for natural gas, and prices are expected to remain high for most of 2003. Upward pressure on electricity prices is also expected throughout most of the year.

Beyond 2003, price expectations are based on a supply-demand balance reflective of average economic growth and demand. Long term prices of both electricity and gas are expected to exhibit considerable volatility while growing moderately, modulated by seasonal factors.

HISTORIC MID-C ELECTRICITY PRICES AND MARKET FORWARDS

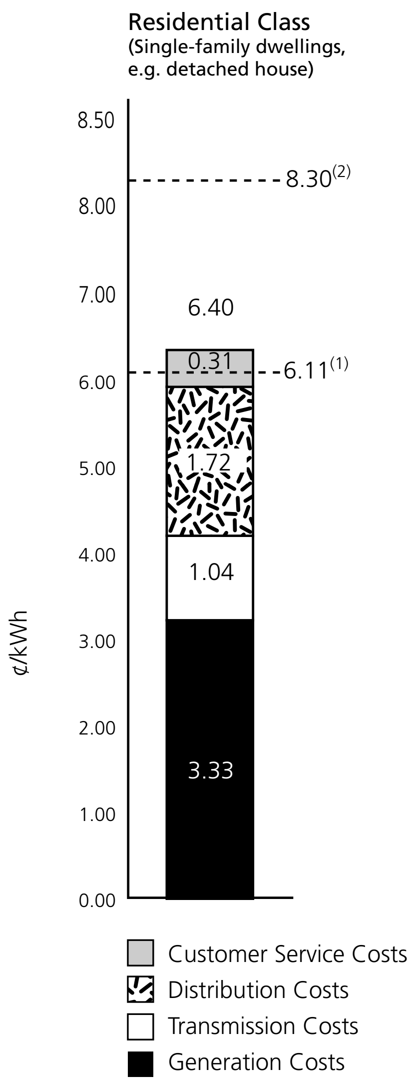


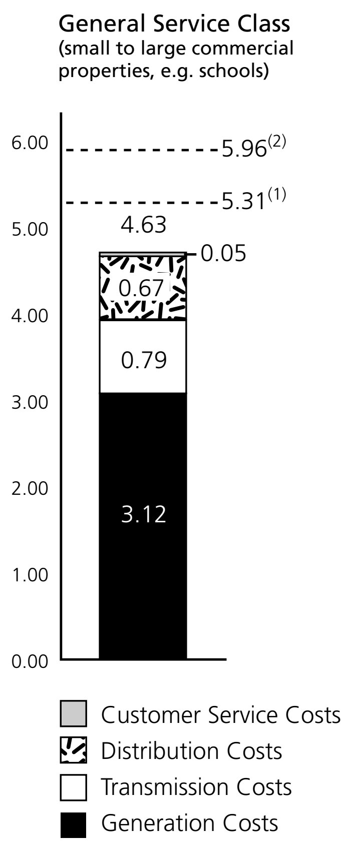
MID-C ELECTRICITY MARKET FORWARD PRICES AND SUMAS NATURAL GAS

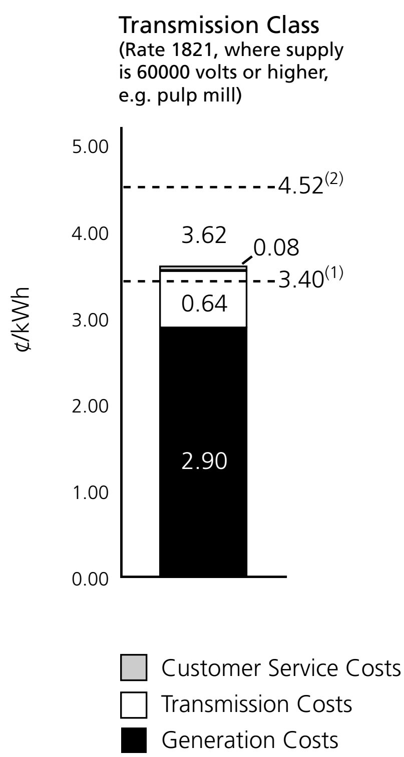


BC HYDRO 2002 COST TO PROVIDE SERVICE

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).







(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.

OPERATIONS

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 each month between 1 January and 1 August for the February–September runoff period. Snowpack levels are closely monitored throughout the year as they are significant contributors to reservoir inflows. The maximum snowpack accumulation usually occurs in the beginning of April and provides the most accurate assessment of the spring and summer snowmelt runoff.

Peace River System

- Precipitation in the Peace River basin during October–December 2002 was well below normal.
- The 1 January 2003 forecast for Williston Reservoir inflows during February–September 2003 is 89 per cent of normal.

Columbia River System

- Columbia / Kootenay basin precipitation was also well below normal during the October-December 2002 period.
- The 1 January 2003 forecast for Kinbasket Reservoir inflows during February–September 2003 is 82 per cent of normal. The forecasts for Revelstoke and Arrow local inflows are 84 per cent and 95 per cent of normal, respectively.
- In the Kootenay region, the 1 January 2003 runoff forecasts for Duncan Reservoir and Kootenay Lake locality are 82 per cent and 79 per cent of normal, respectively.

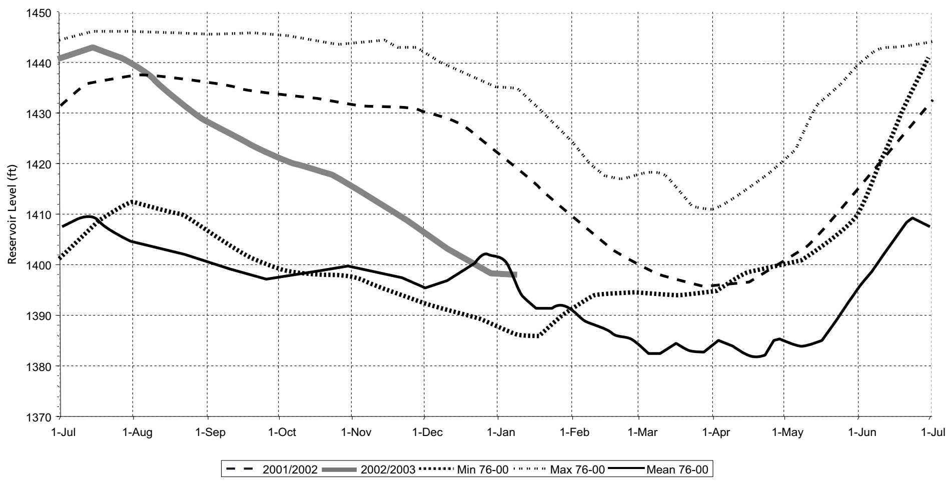
Bridge River / Coastal System

- Precipitation was also generally below normal on the South Coast and Vancouver Island during October–December 2002.
- The 1 January 2003 forecasts for reservoir inflows in the Bridge / Coastal region are generally below normal, but range from 84 per cent of normal at Wahleach in the eastern Fraser Valley to 105 per cent of normal at Comox Reservoir on Vancouver Island.

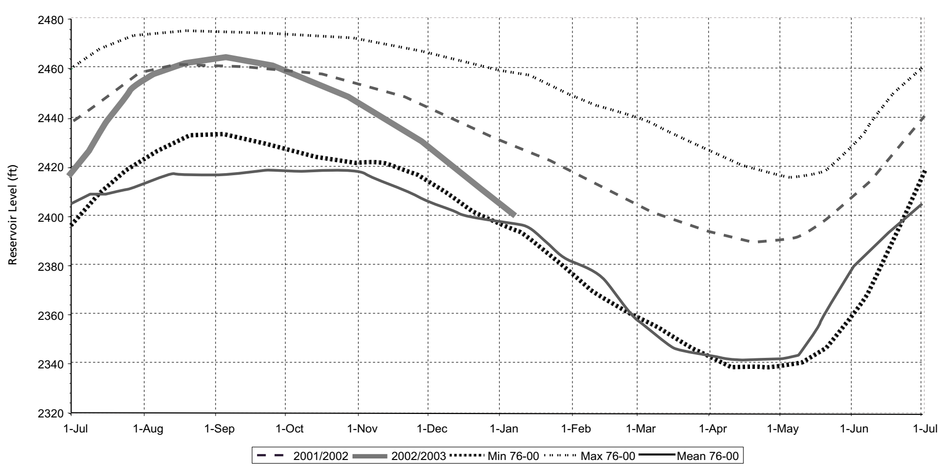
Reservoir Levels

BC Hydro monitors the levels of 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).

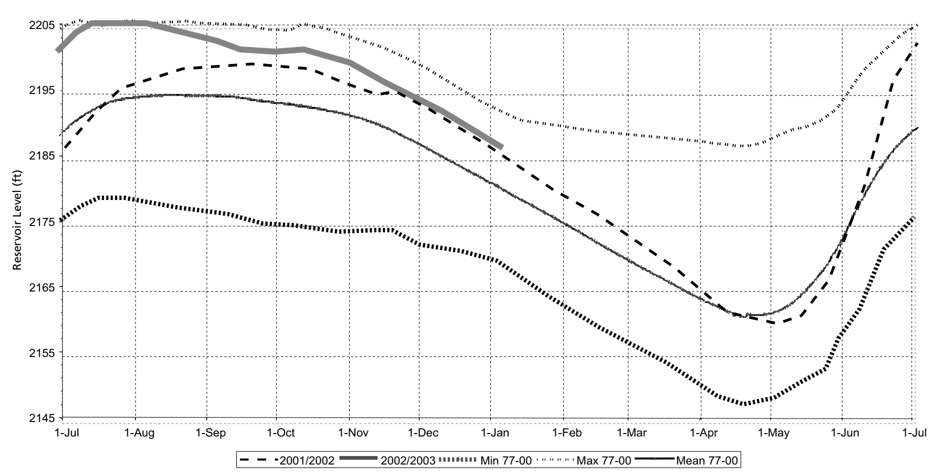
ARROW RESERVOIR LEVELS



KINBASKET RESERVOIR LEVELS

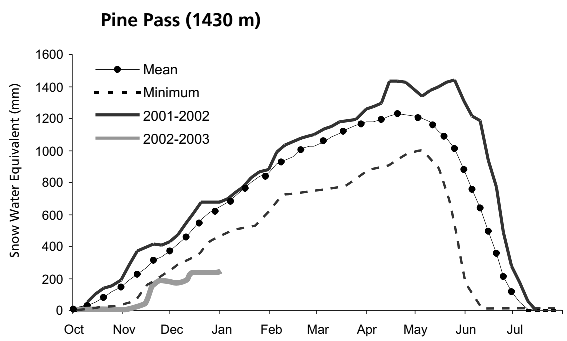


WILLISTON RESERVOIR LEVELS



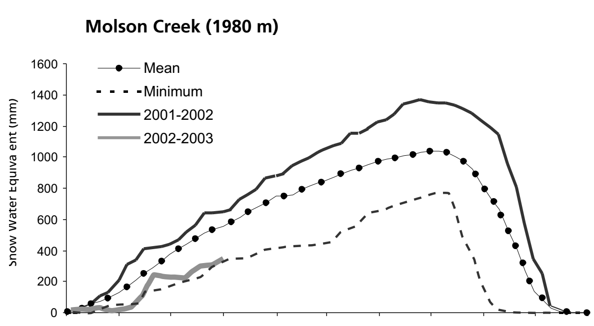
Williston

The water supply forecast for the Williston reservoir (on the Peace River) for February through September 2003 is well below average due to very low precipitation during October and December. As of 1 January the snowpack conditions are well below normal for this time of year with some stations recording below previous minimums. The following plot shows the accumulated snow water equivalent at a representative "snow pillow" recording station within the watershed. For Williston reservoir inflows, the average snowpack component (October–April) is 51 per cent and the average rainfall component (May–September) is 49 per cent.



Columbia

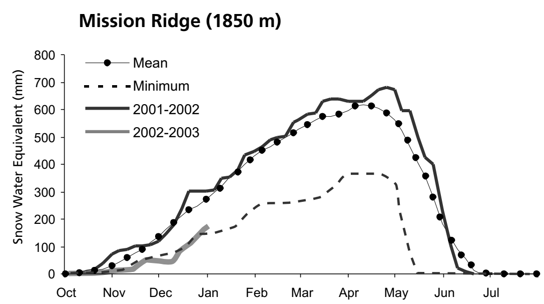
The water supply forecast for the Canadian Columbia River projects for February through September 2003 is well below average except the area around Arrow Lakes that is below but near average. The following plot shows the accumulated snow water equivalent at a representative "snow pillow" recording station within the watershed. For Kinbasket reservoir



inflows, the average snowpack component (October–April) is 68 per cent and the average rainfall component (May–September) is 32 per cent.

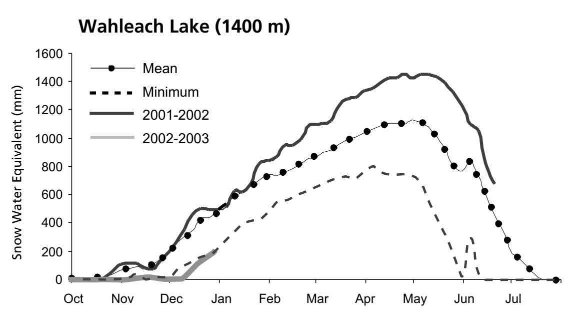
Bridge River

The water supply forecast for Bridge River for February through September 2003 is near average. As of 1 January the snowpack is variable throughout the watershed and below normal. The following plot shows the accumulated snow water equivalent at a representative "snow pillow" recording station within the watershed. For Bridge River reservoir inflows, the average snowpack component (October–April) is 60 per cent and the average rainfall component (May–September) is 40 per cent.



Coastal Projects

The water supply forecasts for projects on the South Coast and Lower Mainland for February through September 2003 vary from near average on Vancouver Island and Howe Sound to below average on the Lower Mainland. The following plot shows the accumulated snow water equivalent at a representative "snow pillow" recording station within the Lower Mainland region.



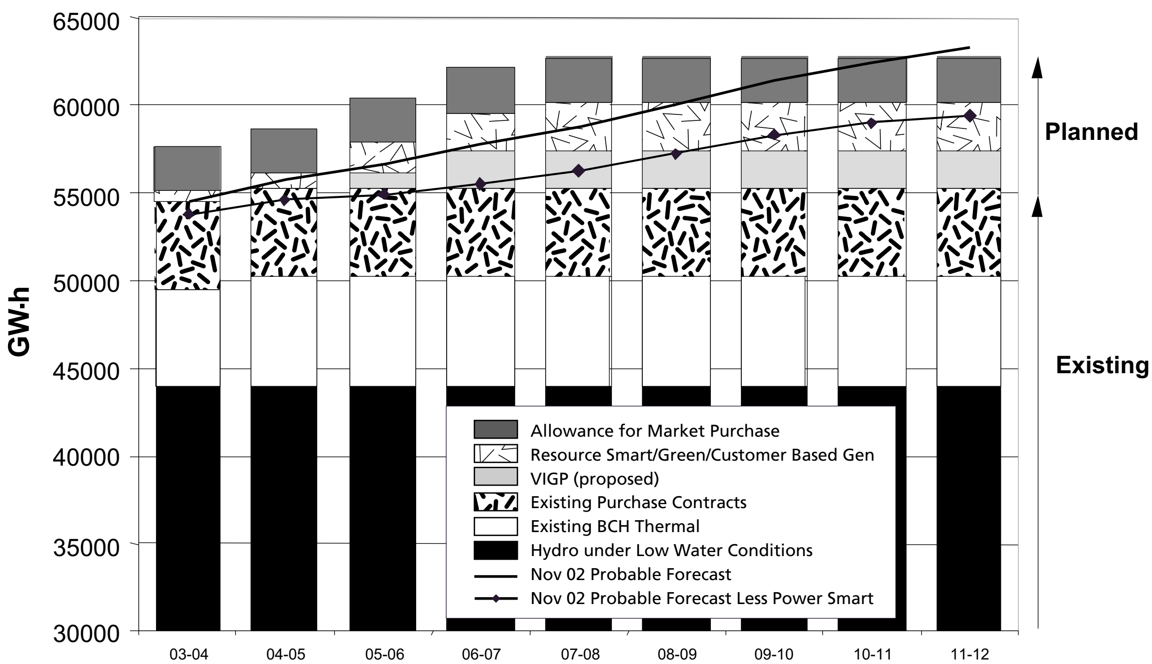
RESOURCES

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 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 with and without the impact of Power Smart to the energy capability of existing and planned new facilities.



Assumptions

- Updated November 2002 Probable Forecast shown with and without Power Smart programs.

Existing Capabilities

Under "Hydro under Low Water conditions":

- Lowest historical streamflow conditions.
- Full use of storage capability of the major reservoirs.
- Contribution from Arrow Lakes Hydro (formerly Keenleyside).

In "Existing BCH Thermal":

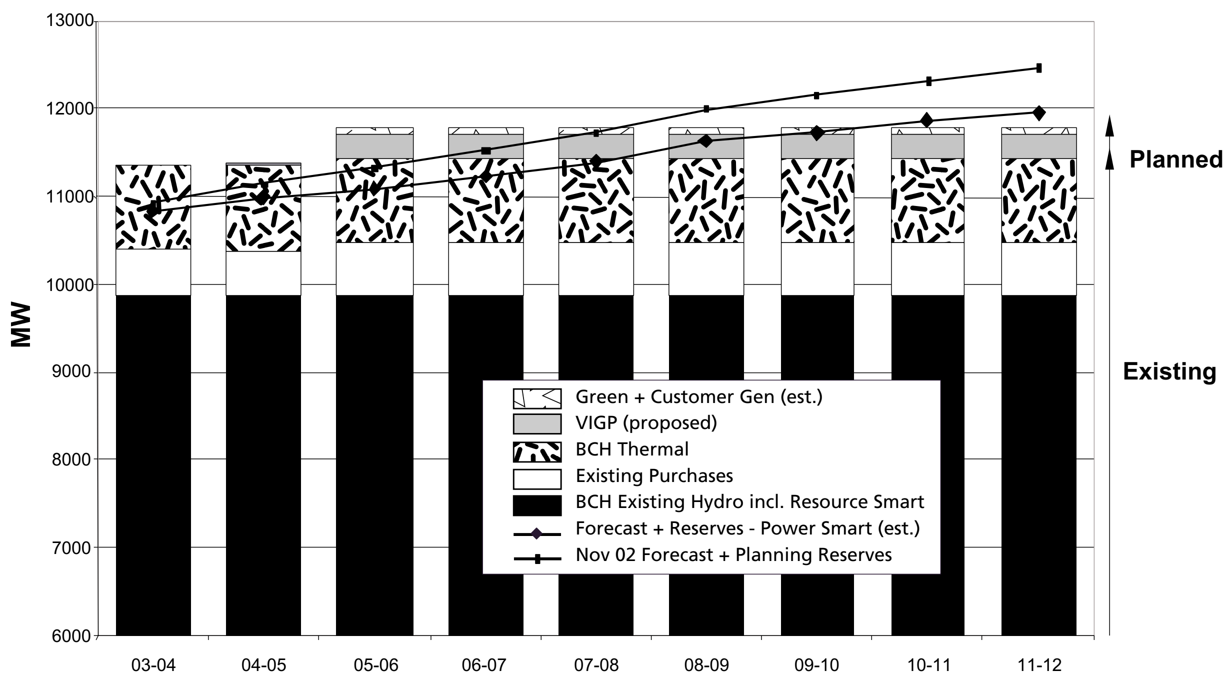
- Maintenance activities at Burrard Generating Station have increased due to the age of the facility. Three units continue to be available for generation on short notice and three units are consistently available to run in synchronous mode for system VAR support. Burrard generation for fiscal 2003 is forecasted to be approximately 160 GW·h, due to the current low prices of electricity on the market. 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

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 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.

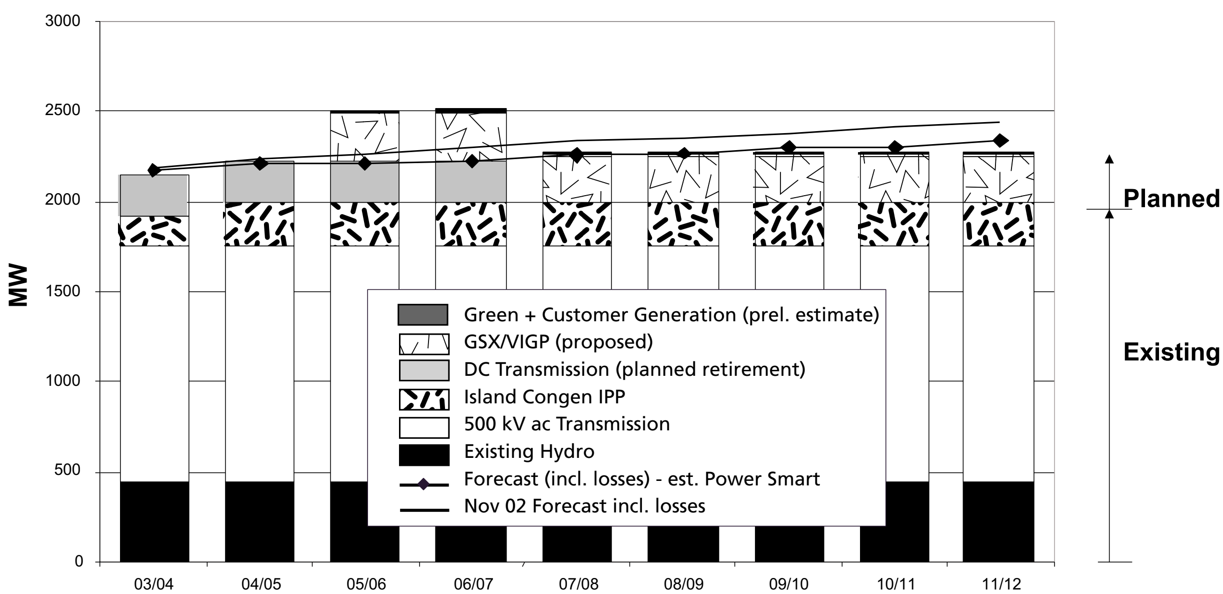
Updated November 2002 Probable Forecast plus reserves shown with and without Power Smart programs.

The Forecast + Reserves – Power Smart represents planning estimates of reduction in peak demand as a result of Power Smart.

For Green Energy and Customer Based Generation a 100 MW contribution of dependable capacity is assumed but is subject to verification depending on the ability of the selected projects to provide capacity to meet system peak requirements with a high degree of confidence.

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. "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.



Assumptions

- Updated November 2002 Probable forecast shown with and without the estimated impact of Power Smart. The estimated impact of system-wide Power Smart savings was allocated to regions based on the ratio of regional demand to system demand. Transmission losses have also been included.
- "Dependable Winter Capacity" of the existing VI hydroelectric system is 450 MW (for 3 hours). Because of the limited storage capacity of the VI hydroelectric plants, 450 MW for 3 hours is the maximum sustainable peak per day during the winter peak period.

- “Continuous Rating” of the 500 kV ac cables is 1200 MW. Their short duration (2-hour) 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 about 220 MW. Island Cogen generation varies between 210 MW and 227 MW depending on the amount of steam supplied to the mill. In recent months, the plant has been derated to 227 MW when it is not supplying steam to the mill, due to problems with the gas turbine.
- The fall of 2005 is the target in-service date for the Georgia Strait Crossing pipeline to Vancouver Island. The spring/summer of 2006 is the in-service date for the Vancouver Island Generation Project.
- The system-wide estimated contribution of dependable capacity was allocated to regions based on the ratio of regional demand to system demand.

5. LINES OF BUSINESS

GENERATION

Introduction

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

Facilities

BC Hydro takes great care maintaining the hydroelectric 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.

Bridge River Generation Area

- Two Bridge River turbine upgrade projects were postponed due to delay in returning G.M. Shrum G7 to service.

Peace Generation Area

- The overhaul of G.M. Shrum G10 was compressed so that the unit could be available for market opportunities. The compression partially offset a two month schedule delay by the contractor, GE. G7 runner replacement was successfully completed and the unit was returned to service on December 12, 2002.

Upper Columbia Generation Area

- All units continued to be operational for winter service. Outages may start mid-February depending on weather and market conditions.

Kootenay Generation Area

- The installation of the new 206 MW unit is continuing at the Seven Mile generating station: assembly of the mechanical components of the turbine and generator, mechanical rotation checks, generator winding, and testing the unit controls and unit protection are nearing completion. All remaining key components are in the station with wet testing scheduled for the 22nd of February. The unit will be available for commercial operation, as per the accelerated schedule, by the end of March.

Thermal Generation Area

- **Burrard Generating Station** – BGS Generation for fiscal year 2003 is forecasted to be approximately 160 GW·h, due to the current low prices of electricity on the market. Burrard generation varies with system conditions, reservoir water inflows, and the market price of energy imports/exports and is available to provide power to the Lower Mainland in the event of system failures. The forecasted need for Burrard generation, in view of the forecast inflows, is currently under review. As an example of how market conditions affect Burrard operations, the cost to import electricity during the third quarter was U.S.$36.00/MW·h, compared to U.S.$42.81/MW·h to run Burrard (so it was cheaper to import electricity than to run Burrard).
- BGS 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). Burrard also plays a valuable role to stabilize voltage in the transmission system when operating in the "synchronous condense" mode.
- Three units continue to be available for generation on short notice and three units are consistently available to run in synchronous condense mode for system support.

- A modern digital control system (DCS) was commissioned on Units 5 & 6, and is fully operational.
- Boiler maintenance is scheduled on Unit 5 commencing February 18 for a duration of three weeks.
- An updated burner management system (BMS) is being installed on Units 1 & 2 to address operational safety issues.
- **Fort Nelson** – FNG continues to run with high availability and is exporting to support the northern grid in Alberta. A one day outage for turbine preventive maintenance work is scheduled for February 2003.
- **Prince Rupert** – the plant is available but currently not operating due to the high cost of production and power available at lower cost from BC Hydro and other market sources.
- **Island Cogeneration Plant** – Calpine Canada owns this thermal power plant. BC Hydro has a long-term contract with Calpine to purchase electricity from this plant in accordance with the terms and conditions of the 1998 Electricity Purchase Agreement between the Calpine and BC Hydro. The ICG plant has a capacity of about 220 MW. ICG generation varies between 210 MW and 227 MW depending on the amount of steam supplied to the mill. In recent months, the plant has been derated to 227 MW when it is not supplying steam to the mill, due to problems with the gas turbine.

Dam Safety

- The annual detailed review of the performance of the WAC Bennett dam by an independent expert as required by the BC Dam Safety Regulator was completed in December 2002.
- The anchoring of the Seven Mile dam to meet current seismic standards is progressing on schedule. Three test anchors were successfully installed through the summer of 2002 to confirm the feasibility of the anchoring project. Preparatory work for the installation of the remaining 51 anchors is well underway. The final designs and tender documents for the spillway improvements are essentially complete.
- The Environmental Assessment Office has accepted the prospectus for the decommissioning of the Coursier dam, and public consultation is planned for January and February 2003.

Safety

- Medical Aid (treatment) + Disabling Injury = 10 to the end of the third quarter (annual target is 12).
- Vehicle Incidents = 9, down from 18 last year.
- Incident Notifications are now consistently meeting the 24-hour reporting requirement.

Response to Climate Change

- In the context of BC Hydro's sustainability focus, we are pursuing four key initiatives to minimize our impact on climate:
    - Power Smart: helping our customers save energy.
    - Resource Smart: getting more energy out of existing facilities.
    - Cleaner Energy: acquiring Greenhouse Gas-free (GHG) or low GHG-intensity power from private producers.
    - GHG Offsets: offsetting 50 per cent of the increase in GHG emissions through 2010 from the Vancouver Island gas-fired power plants.
    - BC Hydro's initiatives have avoided an estimated 30 million tonnes of GHG emissions to date and will avoid an additional 30 million tonnes through 2010.

- BC Hydro is pursuing the acquisition of GHG offsets at international market prices, with an emphasis on acquiring the offsets in British Columbia.

Hat Creek Disposition

- BC Hydro had indicated recently that it had no plans to develop the coal resources at Hat Creek for the foreseeable future. As a result, the Hat Creek coal licences held by BC Hydro will be returned to the Province. The exact form of the transfer of these coal rights and/or the associated assets will be determined with government. BC Hydro will be working with the Province over the coming months to develop a plan for this transition. As part of this plan, BC Hydro will be meeting with local residents, stakeholders and First Nations to provide information and respond to any questions

Water Use Plans

- Water Use Plans (WUPs), which are developed through a structured consultative process, define operating boundaries (balancing environmental, economic, and social values) and, when approved, will set the basis for compliance under both the provincial Water Act and federal Fisheries Act.

Completing the Water Use Plan Program at BC Hydro will increase shareholder value by providing greater security of operations (predictability and flexibility) and greater surety of provincial revenues. The program is critical to managing risks under the Fisheries Act and Fish Protection Act and is proving to be a sound investment in productive relationships with both provincial and federal regulators.

Three WUPs have been submitted (Alouette, Stave and Jordan) and another seven have completed their consultation process (Coquitlam, Cheakamus, Bridge/Seton, Wahleach, Ash, Seven Mile and Shuswap). Most of the plans will be submitted before December 2003. During the third quarter, the consultation process for the Peace system was completed and discussions were initiated regarding a possible delay of up to one year for the submission of plans for the Columbia projects.

TRANSMISSION

Introduction

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

Highlights

BC Transmission Corporation Implementation Project

The British Columbia Government's Energy Plan, released on 25 November 2002, announced the creation of a separate government owned corporation, the BC Hydro Transmission Corporation (BCTC). BCTC will operate and manage BC Hydro's transmission assets, will ensure the province has continued access to trading revenues and will enable independent power producers to access the transmission system. A project has been initiated to transfer the existing BC Hydro Transmission Business to the BCTC and to develop and implement the full scope of activities of the new corporation. The project will be carried out in several phases to coordinate with the implementation of the Energy Plan and regulatory changes.

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 Energy Regulatory Commission (FERC) at the end of March 2002. FERC issued a Declaratory Order on the RTO West Stage 2 filing in September 2002. The Order requested additional filings within 90 and 120 days to address specific issues. The filing dates will not be met as RTO West filing utilities are addressing their own set of priority issues to establish the viability of RTO West, including participation by the Bonneville Power Administration (BPA) in RTO West. BC Hydro has similar concerns to BPA on some matters, such as participation by entities not under FERC jurisdiction and application of market power mitigation measures to hydroelectric generation.

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 will be specifically tailored to the BC Energy Plan and FERC requirements for international participation. Involvement in RTO West provides continued opportunities for BC participation in a broader North American energy market.

Following release of its 31 July 2002 notice of proposed rulemaking (NOPR) on Standard Market Design (SMD), FERC has been actively engaged with western entities, including BC Hydro and Powerex, in furthering the understanding of what it will take to develop a successful market in the west. RTO West has been investigating various elements of SMD to determine how it might meet the requirements of SMD. This includes identifying elements of SMD with which RTO West will comply and elements for which regional variations will be required.

The three western RTOs, RTO West, California ISO and WestConnect, have jointly filed a plan with FERC to address seams issues. (The market design differences among the three RTOs create "seams" at the interface points such that cross-RTO transactions are not done effectively.) This effort, known as SSG-WI (Seams Steering Group – Western Interconnection) will identify issues arising from differences in RTO design and ways to resolve the issues and create a seamless market in the West. SSG-WI will be an RTO managed coordination forum in which the RTOs will have individual decision-making authority, considering the recommendations from SSG-WI.

When operational, RTO West will coordinate regional transmission operations, providing more efficient access to all transmission facilities owned by the participating entities for bulk power transfers. In addition, 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.

Vancouver Island Supply

The critical nature of supply constraints on Vancouver Island was highlighted by recent outages on the two 500 kV transmission circuits that serve the Island from the Mainland.

On 12 December 2002, line 5L32 between Cheekeye and Malaspina substations suffered extensive damage near Sechelt Creek on the Sunshine Coast. Heavy rains combined with snow melt caused a mudslide that pulled down and buried one structure. As a result, two adjacent structures were destroyed, three additional structures received damage to their tower bridges and approximately 1.6 circuit kilometres of conductor was destroyed. A major repair effort was immediately launched by BC Hydro Transmission, Engineering and Field Services employees. Due to the difficult terrain and complex reconstruction effort, the circuit was not expected to be restored before 21 January.

The loss of 5L32 did not result in immediate customer outages on Vancouver Island as there is an adjacent 500 kV circuit 5L30 which remained in service. However, on 26 December 2002, freezing conditions in the Sunshine Coast area caused extremely heavy ice loading on 5L30 which resulted in a flashover. There was an immediate loss of 950 MW (60 per cent) of load on Vancouver Island, including residential, commercial and industrial customers. Residential customers were restored within 36 minutes using on-Island generation. Circuit 5L30 was restored within three hours, allowing the remaining customers to be reconnected.

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 in July 2002, 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 an additional circuit fail. Circuit 2L64 was successfully repaired and returned to service during November.

In December, a Certificate of Public Convenience and Necessity (CPCN) was issued by the British Columbia Utilities Commission for installation of a new underground 230 kV cable circuit 2L33 between Horne Payne and Cathedral Square substations. This $44 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.

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. Distribution is also responsible for BC Hydro's resource planning to meet the needs of our domestic customers.

Resource Acquisition

Vancouver Island Generation Project

The Vancouver Island Generation Project (VIGP) is a new high-efficiency natural gas-fired electricity generation facility to be built at Duke Point near Nanaimo. It is a key project for meeting the electricity supply needs for Vancouver Island. The application to the Environmental Assessment Office (EAO) for a Project Approval Certificate is based on constructing the plant on land to be purchased from Pope & Talbot at the Harmac Mill Site. The application was submitted to the EAO on June 17, 2002, for review under BCEAA Bill 29. The new BCEAA Bill 38 came into effect on 30 December 2002 and a Transition Order was issued for the project review to now be completed under the new act. The cost of the project is estimated at $370 million, based on 90 per cent probability of non-exceedance. The scheduled in-service date will finally be determined based on obtaining all regulatory approvals. An application to BCUC for a Certificate of Public Convenience and Necessity is being prepared to comply with the Province's Energy Plan.

Georgia Strait 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 $340 million cost of the project is based on 90 per cent probability of non-exceedance. BC Hydro's share of this cost would be $171 million. The U.S. federal regulatory approval process for the U.S. portion of the project is complete. The Canadian process is ongoing, and a public hearing has been scheduled to commence on February 24, 2003. A decision from the NEB is anticipated in fall 2003. The in-service date of the project has been rescheduled from October 2004 to October 2005 to accommodate the anticipated Canadian regulatory process timeline.

Vancouver Island Green Energy Demonstration

Project Component	Status to 31 December 2002
2–5 MW Wind Energy Project	A new Key Principles Agreement with revised roles for AXOR and BC Hydro was signed in October 2002. Through the new agreement, the partners will develop a smaller 2–5 MW test bench in Phase 1, followed by scaling up if the site proves viable. BC Hydro and AXOR have filed Crown Land Applications with Land and Water B.C. Outstanding items for discussion include forestry impacts and archaeological studies.
3–4 MW Wave Energy Project	BC Hydro's partners, Energetech and Ocean Power Delivery, are testing their wave energy technologies in their home countries prior to building in B.C. Discussions are underway with NRCan and the National Research Council to test Energetech's turbine technology in Canada.
6–8 MW Micro Hydro Project	A MOU was signed with Synex and a second MOU with Innergex is pending. The objective of the MOUs is to gather information about the development process to aid other developers as Synex and Innergex build their projects.

Green Independent Power Producers (IPPs)

- From the 2001 Green call BC Hydro has 73 signed EPAs totaling 980 GW·h. These IPP projects are in various stages of implementation.
- BC Hydro issued another call for green energy in October 2002 for up to 800 GW·h/year. By the deadline of 16 December 2002, a total of 70 proposed projects were submitted in response to a Request for Qualifications. These Qualification Statements are now being reviewed and a list of qualified bidders is expected to be released in March 2003. The submissions received represent a combined potential capacity of approximately 1000 MW, with a potential annual output of about 5500 GW·h per year. (One GW·h is the amount of electricity consumed by roughly 100 BC homes each year.)

Customer-Based Generation

- BC Hydro is seeking 10 to 20-year agreements to supply new, competitively priced electricity totalling 800 GW·h/year from customer-based generation. In response to a Request for Qualifications, BC Hydro received 38 proposals from customers from all sectors across the province. 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 BC Hydro's Web site. A workshop for potential bidders was held on November 4, 2002. Bids are due to be received on 14 March 2003 and EPAs are expected to be awarded in June 2003.

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 December 2002, 1699 GW·h/year of restored and new energy have been brought into service. Currently there are 13 projects funded and underway, with four in the "Implementation Phase" (503 GW·h/year) and nine in the "Definition Phase" (413 GW·h/year). The weighted average cost of energy from projects in the implementation phase is 2.1 cents per kW·h. The weighted average cost of energy from projects in the definition phase is 3 cents per kW·h.
- Since March 2002, Resource Smart projects completed include Peace Canyon Tailwater Improvement Project (49 GW·h/year); upgrades of two more units at Bridge River (28 GW·h/year), and the first unit upgrade at G.M. Shrum (87 GW·h/year). The Seven Mile Unit 4 project is one year ahead of schedule and on track to come in under budget and be available for commercial operation by April 2003.

Power Smart

- Power Smart continues implementing its comprehensive 10-year plan to reach an annual target of 3500 GW·h in new energy savings, or enough to supply 350 000 homes in British Columbia.
- For business customers, committed and installed opportunities including e.Points savings for this fiscal year total 340 GW·h; for residential customers, savings are at 35 GW·h for a total of 375 GW·h, placing Power Smart on track to exceed this year's cumulative target of annual energy savings of 360 GW·h.
- More than 260 business customers have signed as Power Smart Partners and an additional 340 partnerships are in process. More than 280 applications for incentives, representing 500 GW·h have been received from business customers in response to competitive calls. Examples of customer projects include:

- BC Hydro and Vancouver International Airport Authority announced that the Airport Authority has been recognized as the first Power Smart Certified customer in British Columbia. The Airport Authority has accumulated nearly $2 million in total electricity savings since 1996 and has committed to an aggressive target of a further 15 per cent reduction over the next five years.
- UBC and BC Hydro announced that the university will save a further $600,000 in annual electricity costs by implementing the largest energy retrofit in Canadian history. To date, electricity savings have reached $600,000 through lighting upgrades at 50 buildings throughout the campus, reducing UBC's total annual electricity consumption by 11 per cent.
- In December 2002, Fairmont Hotels became a Power Smart Certified Partner. A recognition event was held at one of Fairmont's five hotels in British Columbia, the Fairmont Hotel Vancouver. The customer has already completed a lighting retrofit at the Fairmont Chateau Whistler that will save 1.9 GW·h per year. As a Certified Partner, Fairmont Hotels have committed to reducing electricity consumption by 20 per cent or almost five GW·h.
- For residential customers, Power Smart initiatives in the Greater Victoria area and Southern Gulf islands launched in October proved highly successful. The first wave of activity on Vancouver Island ended on December 31st with significant success for both the Compact Fluorescent Light (CFL) Program and the Refrigerator Buy-Back (RBB) Program. In the Greater Victoria area, 55 per cent (i.e. over 60 000) of residential households participated in the CFL program over the two month period, resulting in the distribution of 126 000 compact fluorescent light bulbs.
- The Seasonal Light Emitting Diode (SLED) Program resulted in BC Hydro distributing 17 000 holiday light strings to over 60 holiday lighting display organizations across the province to demonstrate this new technology (not currently available in Canada). SLEDs use more than 90 per cent less electricity than standard incandescent seasonal lights, last up to seven times longer and cost substantially less to operate.

Green Power Certificate Initiative

- 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.

Customers

- Net new customer additions totalled 14 794 for the first three quarters, an increase of 30.5 per cent over the same period last year. This increase is one of the largest BC Hydro has seen in many years. This upward trend is expected to continue for the remainder of the fiscal year.
- A temporary back-up generator was installed at Port Simpson in October to avoid lengthy outages until the reliability of the circuit supplying the village could be improved. A capital improvement plan has been created to improve the reliability of the supply to Port Simpson and it is expected that the backup generator will be removed by June 30, 2004.

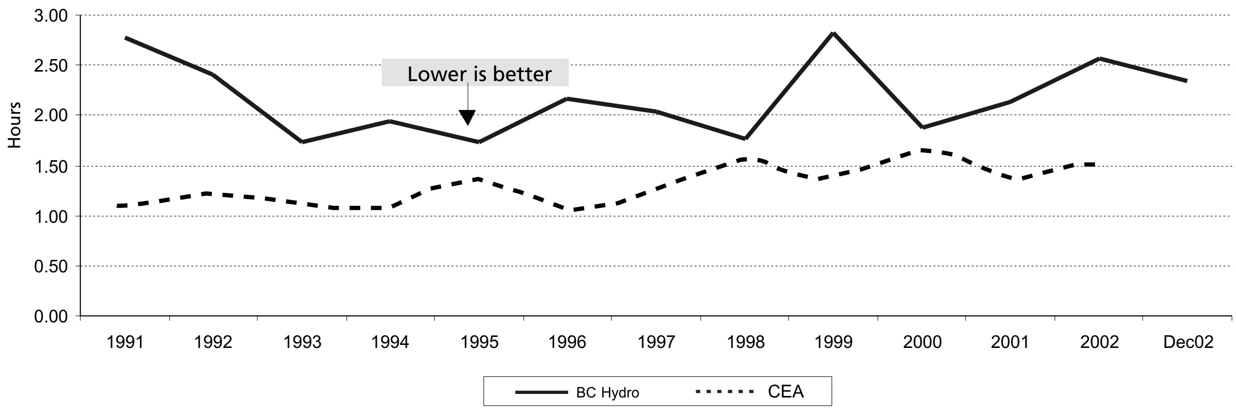
Assets

- The asset health of BC Hydro's distribution plant has declined three per cent this year primarily in the areas of poles, feeder cables, and corridor condition (vegetation control). This will necessitate additional maintenance efforts to stop further deterioration of the assets and ensure that the infrastructure provides the reliability that is expected.
- As more of BC Hydro's distribution plant reaches and exceeds end of design life, not only will there be increasing maintenance challenges but there will be a concurrent need to replace more old equipment. A survey of industry practices confirms that BC Hydro's current Replacement Capital Ratio (RCR) of 1.10 is well below reinvestment levels of most other Canadian and U.S. utilities. Replacement Capital is the expenditure required to sustain or maintain the distribution infrastructure at current levels of system performance. The ratio is the annual investment divided by the replacement cost. BC Hydro is targeting a Replacement Capital Ratio of about 1.44 next year to ensure that reinvestment in aging plant is effectively managed and that the distribution plant can continue to provide safe and reliable service.

Reliability

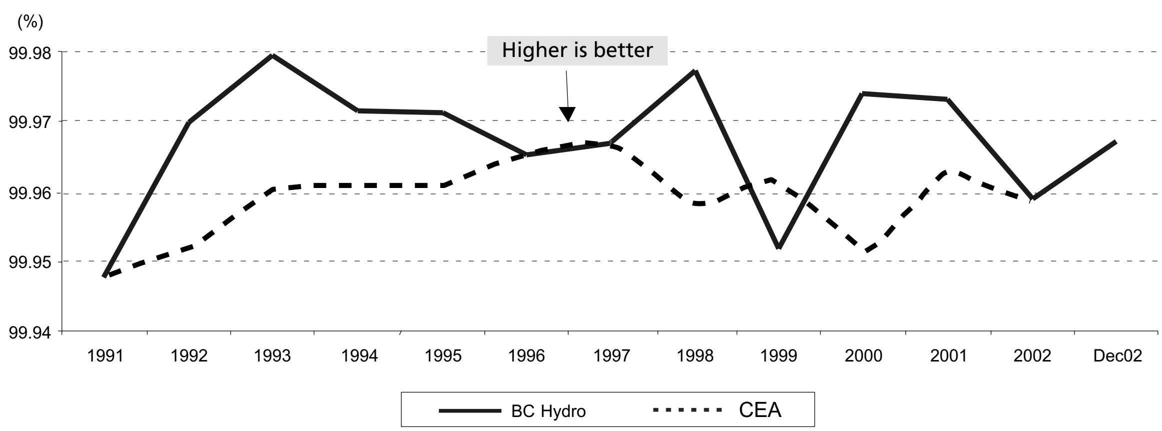
CUSTOMER AVERAGE INTERRUPTION DURATION INDEX (CAIDI)

CAIDI = # Customer Hours Lost / # Customer Interruptions



AVERAGE SYSTEM AVAILABILITY INDEX (ASAI)

ASAI = # Customer Hours Served / # Customer Hours Demanded

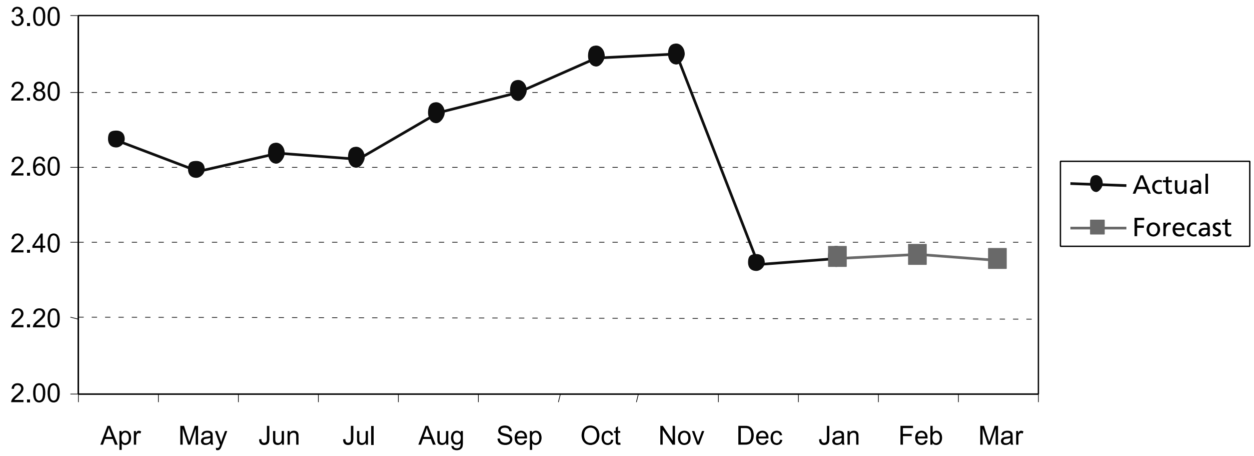


Reliability (12 month year-to-date to December 31, 2002)

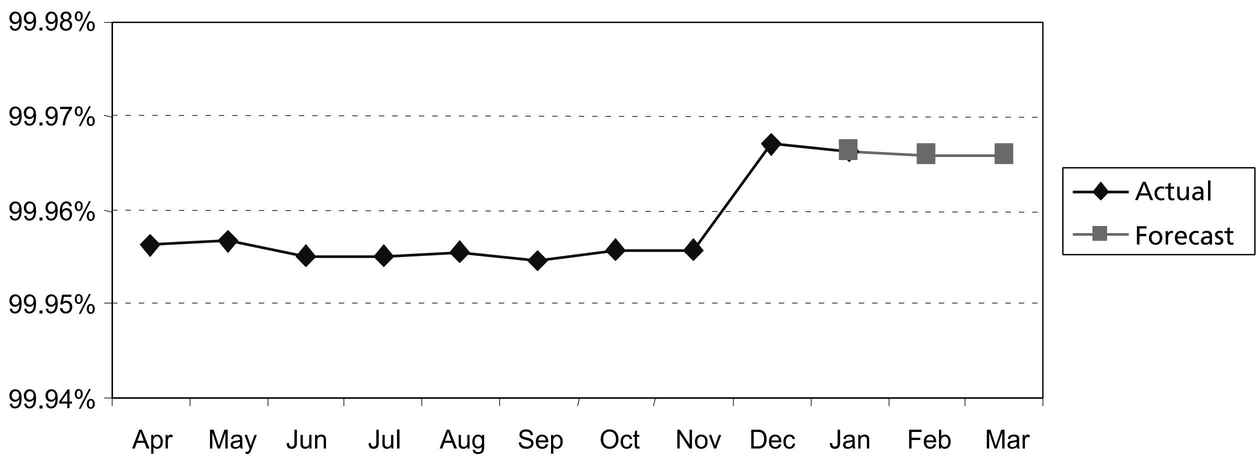
Actual Reliability	**Target Reliability**
ASAI: 99.967%	99.970%
CAIDI: 2.34 hours	2.15 hours

Over the past 10 years our ASAI has averaged 99.969 with a fairly flat trend line while our CAIDI has averaged 2.08 hours with an increasing (deteriorating) trend line. The 12-month rolling average for these measures show that we will be slightly below target for both by year end at 99.966 and 2.36 hours respectively.

ROLLING 12 MONTH CAIDI FORECAST



ROLLING 12 MONTH ASAI FORECAST



ENGINEERING SERVICES

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. Third quarter activities have focused on the delivery of engineering services within scope, schedule, budget and with appropriate quality.

Seven Mile Unit 4 / Dam Safety Improvements Projects

Unit 4: The supply and installation of unit 4 is on schedule for April 2003 commercial service. This accelerated schedule to meet the 2003 spring freshet has had the six major site contractors and many supply contracts working shiftwork and weekends to meet in-service dates. The 250 000 pound turbine runner completed a two-month ocean and river journey in November and the 1.1 million pound turbine rotor was installed in December. Commissioning of the switchgear and electrical panels has commenced.

Dam Safety Improvements: Peter Kiewit & Sons (Contract SM 152 – Dam Anchors) is continuing the chipping of the anchor head recesses. Drilling of the anchor holes is progressing well with a new Italian track drill rig. The site received the first anchor strand shipment in December, which covers the first 18 of the total 57 anchors. The 92 strand anchors being installed at Seven Mile are the largest dam anchors installed in North America to date. Contract SM 153 (Dam Safety Improvements to the Spillway) has been prepared for tender in mid-January and is tentatively closing February 19. The spillway work is to be completed by late 2004.

Vaseux Lake (South Okanagan) Substation

Aquila (formerly West Kootenay Power) is concerned with load growth of, and the supply capacity to, the Penticton load area. Increasing demand will result in overload on Aquila's 11L and 56L/43L transmission lines by the winter of 2005/2006. Aquila has studied supply options to serve the Penticton load area, and has been involved in discussions on this issue with BC Hydro for many years. A supply option of particular interest to Aquila is to tap into BC Hydro's 5L98 500 kV transmission line (Selkirk-Nicola) with the intention of tying into Aquila's 161 kV system near Gallagher Lake, north of Oliver. A 500 kV/161 kV substation in this area could be used by Aquila to supply 161 kV northward to R.G. Anderson Terminal in Penticton and 161 kV southward to Oliver Terminal. These 161 kV lines would be upgraded to 230 kV in future.

BC Hydro is assisting Aquila in a number of ways. Transmission LOB Grid Operations has negotiated and signed a General Wheeling Agreement and Power Purchase Agreement with Aquila. These were part of Aquila's application with BCUC, in conjunction with Aquila's application in respect of its South Okanagan Supply Reinforcement Project, in mid-December 2002. Three points of interconnection have been identified at Creston, Vaseux Lake and Princeton. By wheeling through BC Hydro's system, Aquila avoids the necessity to build new lines to reinforce its Penticton load area supply.

Engineering completed a feasibility estimate for Aquila's CPCN application and is presently concluding an agreement to supply engineering services for the Vaseux Lake Substation. The project would involve construction of a new substation under the existing 500 kV transmission line, with separate 500 kV and 230 kV sections containing, in total, three 500 kV circuit breakers, two 500 kV/230 kV/161 kV 250 MVA transformers, three 230 kV circuit breakers and associated auxiliary equipment and civil works. The interconnection would also require significant changes within BC Hydro's system.

Financial Performance

Key financial metrics for Engineering for fiscal 2003-Q3 are:

Metric	FY03-Q3	Year to Date
Utilization (hourly)	80%	79%
Billable hours	236 k	598 k

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

FIELD SERVICES

Introduction

Field Services, through its own workforce and the Contractors that it administers, provide Service Restoration, Maintenance, Construction (Civil, Electrical and Mechanical), Telecommunications Maintenance, Public Safety, Vehicle and Vegetation services to the three BC Hydro Lines of Business – Transmission, Distribution and Generation. Field Services' primary 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, reinforcement of safe work behaviours and quality incident analysis to prevent incident reoccurrence.

In October 2002, a very successful safety audit was performed in the Field Services Northwest Area. This was the third successive Field Services safety audit with very positive results.

Safety performance also continues to significantly improve. For the nine-month period ended December 31, 2002, Field Services had 30 fewer injuries as compared to the same period last year, with 80 per cent of this decrease in the disabling injury category. This translates into a rolling 12-month Field Services All Injury Frequency (AIF) of 7.6 as compared to 10.1 at the end of March 2002.

In addition, 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. In fiscal 2003, school safety programs have been delivered to approximately 22 000 students and first responder programs to over 2400 attendees.

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.

The selection process is nearing completion for the Strategic Workforce Planning initiative with the filling of 30 of the 32 new trade apprentice and managerial positions planned for fiscal 2003. The remaining two positions will be filled before year-end and risk assessment, analysis and recommendations for future intake are already well advanced.

Trainees within the Field Services workforce account for approximately eight per cent of the Field Services regular workforce.

Progress continues with the implementation of a Kwantlen University College / Electrical Industry Training Institute (EITI) pre-apprenticeship program for Power Line Technicians. An information session was held in early January 2003 at Kwantlen University College where approximately 40 potential students attended the session. A similar number wrote to request that an information package be forwarded to them.

Service Restoration / Customer Reliability

Field Services continues to focus on service restoration and customer reliability. Recent examples of Field Services efforts involving service restoration and customer reliability include multiple storm-related / landslide outages in Port Simpson / Kitkatla; the landslide forced the outage of 5L32 on the Sunshine Coast; the weather-related outage involving 5L30; and severe windstorms in the Lower Mainland and Vancouver Island resulted in numerous customer outages on December 12 and Christmas Day.

Financial Summary

Field Services has been created as a cost recovery business unit within BC Hydro and for the first nine months ended December 31, 2002, recoveries have marginally exceeded costs by one per cent.

Field Services recoveries were $203 million compared to a plan of $183 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. The higher than plan recoveries are mainly related to increased external Contractor work associated with increases in economic activity (e.g. net new customer additions are currently 12 per cent above plan) and increased customer restoration work.

Internal recoveries account for over 98 per cent of the total recoveries. Approximately 70 per cent of these recoveries are derived from an internal BC Hydro workforce, with the remaining 30 per cent from external Contractor workforces.

Third party recoveries are derived mainly from Industrial customers and reflect niche or specialty work that is not performed at the expense of external Contractor workforces.

Internal workforce chargeable hours are tracking near Plan levels with 1 350 000 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. External Contractor use remains at 20 per cent above plan levels.

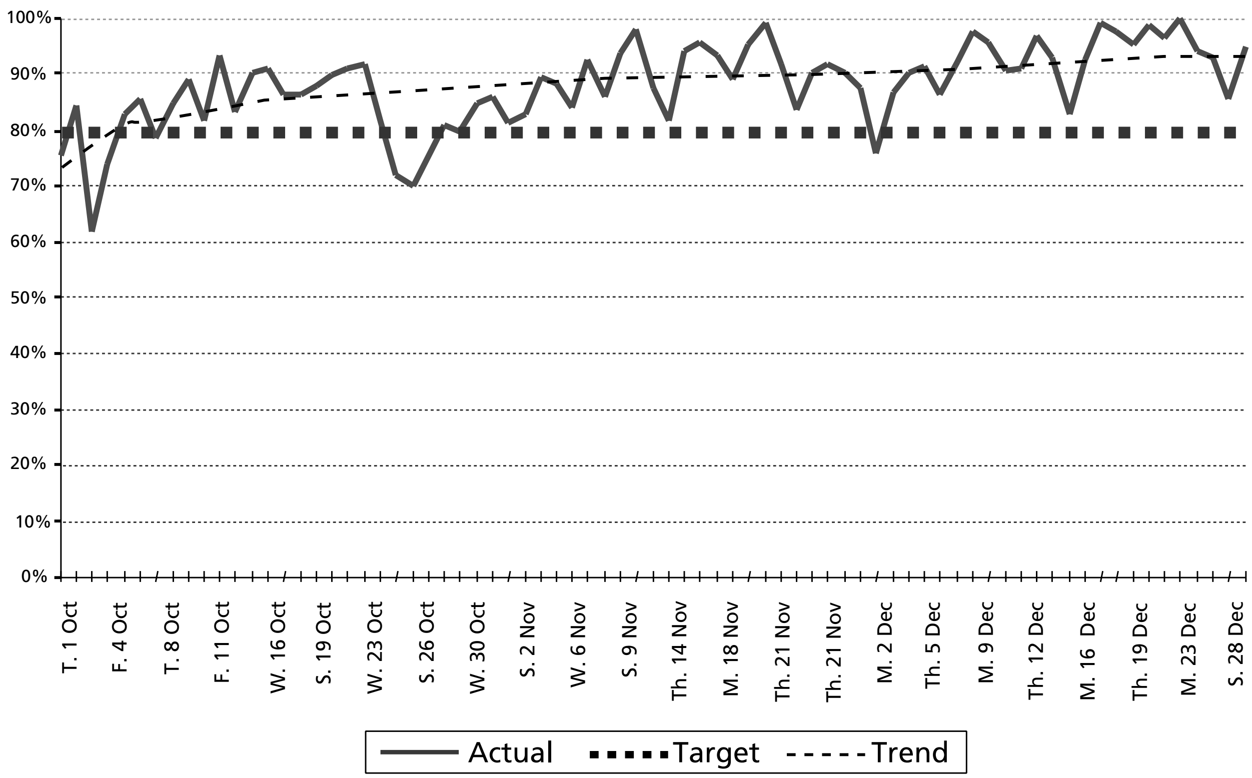
SHARED SERVICES

The Shared Services organization within BC Hydro provides a range of products and services that include Customer Services, Information Technology, 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 CSR.

CUSTOMER CARE SERVICE LEVEL – OCTOBER 1 TO DECEMBER 31, 2002

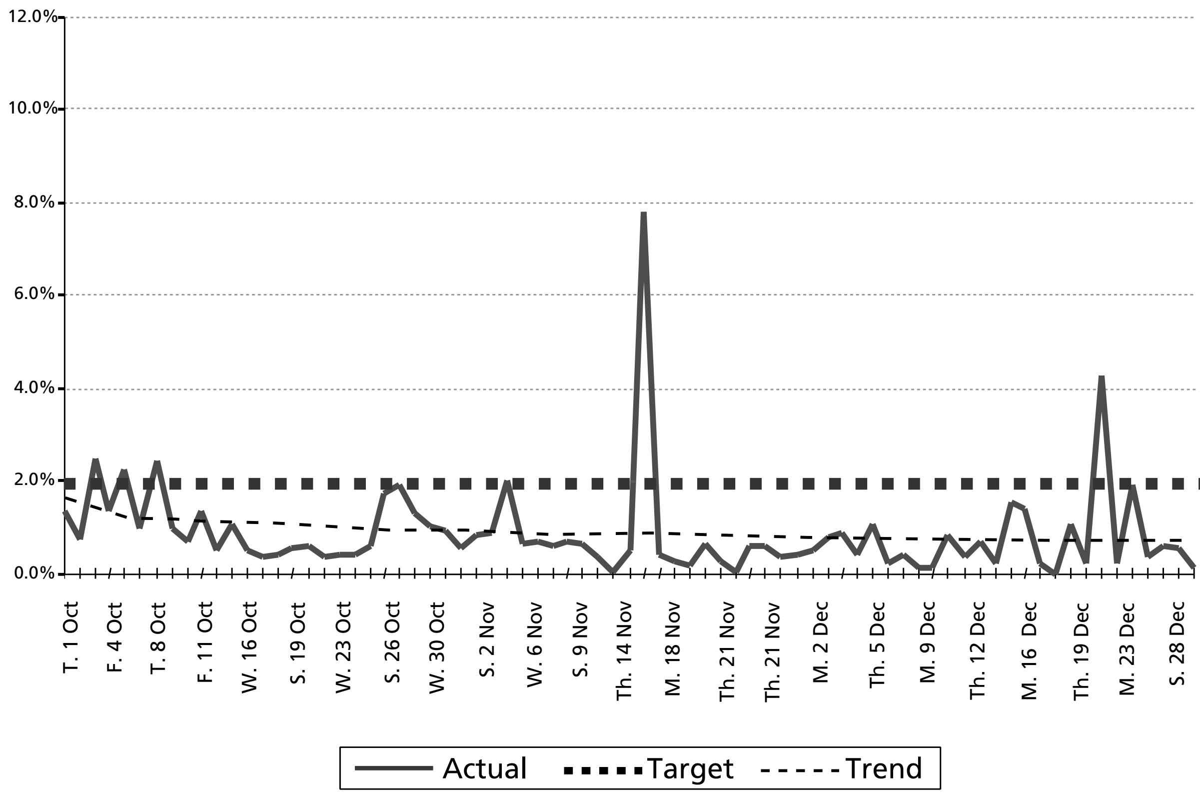


In the third quarter of the current fiscal year, warmer weather and the repatriated gas calls appear to have had an impact on overall call volumes to the call centre. Total calls offered to the IVR for the third quarter of the current fiscal year were approximately 634 800 compared to 715 600 calls for the same period last year. This represents a decrease of 11.3 per cent. Although call volumes for the year-to-date are still up 5.4 per cent, the overall trend appears to be lower.

Even with a successful Vancouver Island Power Smart initiative launched mid-quarter, which produced a substantial increase in calls to the Power Smart number, total calls answered by CSRs were just over 416 700 for the quarter. This compares to 452 400 for the same period last fiscal year, a decrease of 8.6 per cent. However, total calls answered are still up 4.4 per cent overall for the year-to-date.

In the third quarter of the current fiscal year, the call centre achieved an overall adjusted Customer Care service level of 88 per cent, which compares favourably to our target of 80 per cent. The adjusted abandonment rate of 0.6 per cent for the quarter also continues to compare favourably to our maximum target of 2.0 per cent.

PERCENTAGE OF TOTAL CALLS ABANDONED – OCTOBER 1 TO DECEMBER 31, 2002



Lower call volumes and better matching of resources to schedules helped bring up our overall, year-to-date Customer Care service level to our target of 80 per cent. The adjusted year-to-date abandonment rate is currently at 1.2 per cent. A major outage on November 16 resulted in approximately 6100 trouble calls and the high percentage of abandoned calls recorded that day.

RFEI Update – Combined Bid

In anticipation of creation of the new Joint Venture Entity, the Shared Services group continues to plan for transition into the new organization for Day 1 on April 1, 2003. During the quarter, John Icke was named president of the new joint venture entity – Accenture Business Services of British Columbia (ABS). As part of BC Hydro's Employee Transition Options plan, elections were held in December to allow eligible employees to vote on whether to move to the new company. More than 90 per cent of the Office and Professional International Union (OPEIU) employees have chosen to move to ABS.

Both Management & Professional and OPEIU Employee workshops were held and offer letter packages were distributed to employees and returned to Human Resources. Over 90 per cent of the employees have chosen to move to the new company.

Westech Information Systems

Westech has had major participation in BC Hydro IT initiatives focused on the FBT (Finance Business Transformation), Portal Work Management System project, Northstar Customer Information System, EGIS (Enterprise Geographic Information System) projects, and Grid Operations. Westech was awarded the Project Management role for the Grid Operations Outage Scheduling project. This tool will replace the final component of the legacy Production Facility Management System (PFMS) system and allow Grid Operations to better co-ordinate outage requests.

Network Computing Services

The legacy mainframe server was successfully replaced with two new state-of-the-art servers. One server is used for the Payroll & Human Resources System and Time Capture PeopleSoft applications. The other one is being used for the remaining legacy applications including the Customer Information and Billing system.

A Service Level Agreement was signed with Transmission Grid Operations – Operations Control, Applications and Infrastructure group for services provided by both NCS and Westech. The agreement was the first where NCS and Westech collaborated to create a single unified service agreement with a joint customer.

An agreement was reached with Powerex to install an independent Exchange e-mail system, with e-mail archival capabilities. This project will allow Powerex to meet FERC regulatory requirements for electricity trading. Scheduled to start in January 2003, this is another combined Westech/NCS consolidated approach.

Disbursement Services

Preliminary work has been done to revise annual vacation processing for BC Hydro to comply with Bill 66 (Public Sector Employers Amendment Act) which, in part, changes the processing method for annual vacation leave. Effective in 2003, annual vacation entitlements must be taken within a two-year period or will automatically be paid out to the employee. This applies to Management and Professional employees only; it does not apply to Hydro's OPEIU and IBEW employees or any employees who will be transferring to Accenture.

We are continuing to monitor the performance of the Peoplesoft Time and Labour module. The mainframe server has been upgraded twice by NCS and response times are still problematic.

Northstar Project

Overall, the Northstar Project (Customer Information System) is progressing well and is on schedule and on budget. Highlights of the third quarter accomplishments include:

- Business Case completed and overall project funding approved by the Board of Directors.
- Interfacing Architecture, a significant component of Northstar, has been completed.
- Technology architecture upgraded to enhance overall system performance.
- Quality Assurance Reviews completed and no major issues identified.
- Awarded Accenture's "Most Inspiring Project" Award for North American Utilities for 2002.
- Over 450 employees participated in four successful Northstar Open Houses in Edmonds, Nanaimo, Prince George and Vernon.

Portal Project

The project involves the design and implementation of a browser-based work management and supply chain system to manage work, supply materials and services, and link information between systems. The project is going live on April 22, 2003 and is on track.

SAFETY PERFORMANCE

During the third quarter, BC Hydro's safety performance continues to exceed our quarterly safety goal by achieving more than its targeted reduction in the combination of injuries requiring medical treatment and disabling injuries. All Injury Frequency (AIF) is a standard measure of both disabling and medical aid injuries per 200 000 hours worked. Our target for the quarter was a 7.5 per cent reduction in AIF and we achieved an actual reduction in AIF of 16 per cent. We continue to make significant progress toward our goal of being a first quartile performer in worker and workplace safety.

Our Continuous Improvement Safety Management System continues to be monitored by audits conducted around the province. During the third quarter we audited Bridge River and Coastal Generation Area (generation workers), Field Services – Northwest area of the province (line workers), and our Materials Management Business Unit (warehouse and material handlers), located in Surrey, and their satellite locations around the province. Our Safety Management System audits assess all work locations over a 24-month period.

Because of our method of sharing all our safety information, including audit findings, we see quarter over quarter improvements in audit scoring in all of the key elements of our safety system. An essential component of our safety system is Safety Leadership behaviours. These are measured by management's presence at the work sites, and guidance and messaging by our leaders on the importance of safety, i.e., demonstrating their commitment through action. We were especially pleased to see the exceptional results of 94 per cent compliance in the "Safety Leadership" elements of our third quarter audits.

Another way in which knowledge is resulting in improvements is how we learn from our mistakes. Safety Incidents, from minor to potentially very serious, are all investigated through a standard "root cause" analysis. The learnings from these investigations are available for all employees, team leaders, safety committees and managers to benefit from. To date, we have investigated 123 incidents and implemented 410 corrective actions to reduce the likelihood of these incidents happening again.

Our goal is to be a first quartile performer; our vision is having "ZERO INJURIES". The benchmarking, audit scoring, and other measuring is the way we track our progress, but it is seeing "healthy employees working safely" that we know we have got it right.

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 third quarter, baseline retirement projections from 2003–2014 were developed for key occupational groups in each line of business and service organization. Projections will be used in conjunction with resource optimization to forecast workforce gaps and develop plans for workforce renewal.

The number of new hires by the end of the third quarter was 78 regular employees. Limited hiring opportunities have been strategically focused on occupations most critical to core operations and most at risk due to retirements (trades, technologists and technicians and engineers). Employee attrition, which includes retirements, resignations and other terminations, was 4.8 per cent or 257 employees. Retirements represented the major component of attrition, with 144 regular employees retiring or completing pre-retirement leaves by December 31, 2002. In total, 679 employees are eligible to retire with unreduced pension in fiscal 2003, but many are choosing to defer retirement.

REGULATORY

On December 17, 2002, the British Columbia Utilities Commission ("BCUC" or "Commission") approved BC Hydro's application for 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 the project is $44 million. The 230 kV line will replace an existing 45 year-old cable circuit which is nearing the end of its useful life. Installation of the line will be along a new route to improve system reliability and provide a seismically secure supply to the downtown area.

The Commission approved an extension to the current Power Sale Agreement between the City of New Westminster and BC Hydro to June 30, 2003. BC Hydro and the City will negotiate a new Power Sale Agreement and the new rate will be retroactive to January 1, 2003.

BC Hydro filed an application with the Commission on December 17, 2002 for an Order approving amendments to the General Wheeling and Power Purchase Agreements between Aquila Networks Canada (British Columbia) Ltd. and BC Hydro. This application was filed in conjunction with Aquila's application for a CPCN to construct the Vaseux Lake Terminal Station near Oliver, BC. The Commission has established a written public hearing process to review the application. A technical workshop will be held in Penticton, BC on January 15, 2003 and the written hearing will conclude on February 21, 2003.

As a major shipper on Centra Gas' high pressure transmission line supplying natural gas to the ICP and proposed Duke Point facility, BC Hydro participated in a Negotiation Settlement Process sponsored by BCUC staff regarding Centra's 2003 to 2005 forecast revenue requirements application. All parties to this process accepted the proposed settlement package, and on December 24, 2002, it was submitted to the Commission and to parties who did not participate in the settlement negotiations for consideration.

The Canadian process for reviewing the Georgia Strait Crossing (GSX) Project is ongoing and nearing the final stages of the information request process. On November 25, 2002, the Joint Review Panel requested all parties to this proceeding to submit comments on whether the GSX application is ready to be set down for an oral hearing. A hearing date has been set for February 24, 2003. A pre-hearing conference to discuss key technical and scientific issues associated with the marine portion of the Canadian segment of the project was held in Sydney, BC on November 14 and 15, 2002.

The issuance of the Province's Energy Plan on November 25, 2002, contained several policy actions that will entail major public hearings before the Commission in 2003 as BC Hydro returns to full regulation. There will be an inquiry by the BCUC to recommend the terms and conditions of a legislated heritage contract that will lock in the value of existing low-cost generation. The rate freeze will expire on March 31, 2003 and a revenue requirement hearing will be held by the end of fiscal 2003/04 to review BC Hydro's costs. A new entity, BC Hydro Transmission Corporation, will be established with terms of service and rates for this company to be determined.