

# FINANCIAL RESULTS

## MANAGEMENT DISCUSSION AND ANALYSIS MARCH 31, 2009

The Management Discussion and Analysis reports on British Columbia Hydro and Power Authority's (the Company) consolidated results and financial position for the year ended March 31, 2009 (fiscal 2009). This discussion should be read in conjunction with the audited consolidated financial statements and related notes of the Company for the years ended March 31, 2009 and 2008. The financial statements have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) and are expressed in Canadian dollars. 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 from those contemplated in the forward-looking statements.

BC Hydro's results for fiscal 2009 benefited from increased income from energy trading activities, but were adversely impacted by lower domestic revenues, higher energy costs, higher amortization expense and higher finance charges compared to the prior year. Certain differences between planned and actual amounts are transferred to regulatory accounts for inclusion in future rates.

### HIGHLIGHTS

- Net income for the year ended March 31, 2009, was \$366 million compared to \$369 million in the prior year. This resulted in a return on equity, based on equity as defined for regulatory purposes, of 11.75 per cent compared with 11.33 per cent for fiscal 2008.
- On March 13, 2009, the British Columbia Utilities Commission (BCUC) issued a final decision with respect to BC Hydro's F2009/2010 Revenue Requirements Application (RRA). The BCUC approved a rate increase for fiscal 2009 of 2.34 per cent and a 0.5 per cent rate rider for the purpose of recovering a portion of the current balances in the deferral accounts. Both are effective April 1, 2008. The BCUC also directed that the difference between the interim rate and the final rate be refunded to customers.
- Hydro generation levels for the year ended March 31, 2009 were 14 per cent lower than in the prior year as a result of lower than average system inflows into system reservoirs compared with higher than average inflows in the prior year. To continue to meet domestic load requirements, BC Hydro was required to purchase more energy from the market which is more expensive than energy generated from its system, increasing the overall cost of energy. This was partially offset by reduced load as a result of lower sales to large industrial customers primarily as a result of closures of pulp and paper mills due to weakness in the forestry sector.
- Property, plant and equipment expenditures of \$1,400 million are 30 per cent higher than the prior year (\$1,076 million) primarily due to the Vancouver Island Transmission Reinforcement project, Revelstoke Unit 5 installation and system improvements to the distribution network. This is a positive result given BC Hydro's significant capital expenditure requirements over the next several years in order to be able to continue to meet load growth requirements and maintain its aging infrastructure.

## FINANCIAL RESULTS

For the year ended March 31

(in millions)

	2009	2008	Change
Total Assets	\$ 16,368	\$ 14,447	\$ 1,921
Shareholders' Equity	\$ 2,189	\$ 1,921	\$ 268
Income (Loss) Before Regulatory Accounts	\$ (72)	\$ 227	\$ (299)
Net Income	\$ 366	\$ 369	\$ (3)
Accrued Payment to the Province	\$ —	\$ 288	\$ (288)
Return on Equity, as defined for regulatory purposes	11.75%	11.33%	0.42%
Debt to Equity ratio, as defined for regulatory purposes	81 : 19	70 : 30	—
Number of Domestic Customers	1,801,038	1,766,937	34,101
GWh Sold (Domestic)	52,512	53,300	(788)
Total Reservoir Storage (GWh)	14,915	14,120	795
Property, Plant & Equipment Additions	\$ 1,400	\$ 1,076	\$ 324

## CONSOLIDATED RESULTS OF OPERATIONS

BC Hydro reports net income (loss) both before and after net changes to regulatory accounts. As a rate-regulated utility, BC Hydro applies various accounting policies that are acceptable under Canadian generally accepted accounting principles (GAAP) for rate-regulated enterprises but differ from enterprises that do not operate in a rate-regulated environment. These policies allow for the deferral of amounts that under GAAP would otherwise be recorded as expenses or income in the current accounting period. The deferred amounts are either recovered or refunded through future rate adjustments.

BC Hydro presents its financial statements on a gross view which shows its results under GAAP in the absence of rate regulation (Income Before Regulatory Account Transfers) and with rate regulation (Net Income). The net change in regulatory accounts on the income statement includes: variances between planned amounts from the most recent revenue requirements application and actual results for cost of energy (including variances related to load) and trade income; certain amounts incurred in the current period that are deferred for future recovery in rates (such as demand-side management expenditures); interest accrued on regulatory accounts where allowed; and amortization of regulatory accounts. As a result, there can be significant differences between income before regulatory account transfers and net income.

For the year ended March 31, 2009, loss before regulatory account transfers was \$72 million compared to income of \$227 million in the previous year. The decrease was a result of lower domestic gross margin, arising from both lower domestic revenues and higher energy costs, amortization expense and finance charges, partially offset by higher trade margins and lower operating costs.

Transfers to regulatory accounts for the year were mainly comprised of transfers to the Heritage Deferral Account related to higher cost of energy than planned and to the demand-side management regulatory account. The BCUC decision on the RRA required BC Hydro to establish new regulatory accounts for the deferral of variances between actual and planned costs for finance charges, taxes, amortization on capital additions, net employment costs included in operating costs and storm-related cost variances, all of which are reflected in the fiscal 2009 results.

Net income for the year ended March 31, 2009 was \$366 million, compared to \$369 million in the previous year. BC Hydro's net income decreased from fiscal 2008 mainly due to lower domestic gross margin and higher operating costs, partially offset by higher trade income and lower finance charges after deferral.

## FINANCIAL RESULTS

### REVENUES

Revenues are influenced primarily by the volume of energy consumed by customers and market prices of energy. Domestic revenues are influenced by variables such as number of customers, average temperatures during the year, level of economic activity in commercial and industrial sectors, and mark-to-market gains or losses on forward energy purchase contracts which are recorded in revenues. Trade revenues are influenced by commodity prices and sales volumes for electricity and natural gas.

	<i>(in millions)</i>		<i>(gigawatt hours)</i>	
	2009	2008	2009	2008
<b>Domestic</b>				
Residential	\$ 1,197	\$ 1,171	17,861	17,553
Light industrial and commercial	1,054	1,054	18,265	18,406
Large industrial	481	536	14,303	15,380
Other energy sales	82	183	2,083	1,961
<b>Total Domestic</b>	<b>\$ 2,814</b>	<b>\$ 2,944</b>	<b>52,512</b>	<b>53,300</b>
<b>Trade</b>				
Electricity – Gross	\$ 2,290	\$ 2,402	32,504	37,450
Less: Forward Electricity Purchases <sup>1</sup>	(1,125)	(1,391)	—	—
Electricity – Spot	1,165	1,011	—	—
Gas – Gross	1,175	858	18,295	14,365
Less: Forward Gas Purchases <sup>1</sup>	(885)	(603)	—	—
Gas – Spot	290	255	—	—
<b>Total Trade</b>	<b>1,455</b>	<b>1,266</b>	<b>50,799</b>	<b>51,815</b>
<b>Total</b>	<b>\$ 4,269</b>	<b>\$ 4,210</b>	<b>103,311</b>	<b>105,115</b>

<sup>1</sup> Forward purchases include derivatives which are deducted from gross sales in accordance with generally accepted accounting principles.

Total revenue for the year ended March 31, 2009 was \$4,269 million, an increase of 1.4 per cent over the previous year mainly resulting from higher trade revenues due to higher average commodity prices and gas sales volumes, partially offset by lower trade electricity sales volumes. Domestic revenues were lower than the prior year due to weakness in the large industrial sector and losses on forward energy purchase contracts which are included in other energy sales.

#### DOMESTIC REVENUES

Total domestic revenues of \$2,814 million for the year ended March 31, 2009 were \$130 million or 4.4 per cent lower than the previous year. The decrease was mainly due to a 1.5 per cent decrease in domestic sales volumes primarily as a result of lower consumption in the large industrial sector due to closures during the year of operations in the pulp and paper sector, and losses on forward energy purchase contracts. This was partially offset by higher average customer rates in all rate classes and an increase in the rate of customer growth.

## FINANCIAL RESULTS

### TRADE REVENUES

BC Hydro's electricity system is interconnected with systems in Alberta and the western United States. Interconnection facilitates sales and purchases of electricity outside of British Columbia. Energy trade activities are carried out by Powerex, a wholly owned subsidiary of BC Hydro. 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.

Trade revenues for the year ended March 31, 2009 increased by \$189 million over the previous year due to both electricity and gas activities. The increase in trade electricity sales includes a decrease in forward electricity transactions of \$266 million, which are netted with forward purchases in revenue in accordance with GAAP, offset by a \$154 million increase in spot electricity sales. Electricity revenues for the year reflect higher sales prices offset by a decrease in gross electricity sales volume of 13 per cent. Electricity sales prices increased as Powerex increased sales in the US Southwest and in Alberta during peak times while the decrease in sales volumes reflected diminishing spreads in US markets in the latter half of the year. Gas revenues increased by \$35 million reflecting an increase in gas sales prices of 8 per cent as well as a 27 per cent increase in gas sales volumes. The increase in gas sales prices was driven by increased supply concerns in the early part of the year while the increase in volumes reflected Powerex's strategy to grow its gas business.

### ENERGY COSTS

Energy costs are influenced primarily by the volume of energy consumed by customers, the mix of sources of supply and market prices of energy. The mix of sources of supply is influenced by variables such as the current and forecast market prices of energy, water inflows, reservoir levels, energy demand and environmental and social impacts.

Energy costs are comprised of the following sources of supply:

	<i>(in millions)</i>		<i>(gigawatt hours)</i>		<i>(\$ per MWh)</i>	
	2009	2008	2009	2008	2009	2008
Hydroelectric (water rental payments)	\$ 310	\$ 318	44,348	51,655	\$ 7.07	\$ 6.10
Purchases from Independent Power						
Producers and other long-term contracts	544	481	8,374	7,765	64.96	61.94
Other electricity purchases – Domestic	271	152	5,020	2,259	53.98	67.43
Gas for thermal generation	58	60	312	423	185.58	141.84
Transmission charges and other expenses	79	63	116	115	—	—
Allocation to/from trade energy	(26)	(126)	(65)	(2,412)	79.08	56.04
<b>Total Domestic</b>	<b>\$ 1,236</b>	<b>\$ 948</b>	<b>58,105</b>	<b>59,805</b>	<b>\$ 21.27</b>	<b>\$ 15.85</b>
Other electricity purchases – Trade – Gross	\$ 1,729	\$ 1,912	32,086	34,020	\$ 88.96	\$ 55.27
Less: forward electricity purchases	(1,125)	(1,391)	—	—	—	—
Other electricity purchases – Trade – Spot	604	521	—	—	—	—
Remarketed gas – Gross	1,127	828	18,797	14,939	59.96	55.43
Less: forward gas purchases	(885)	(603)	—	—	—	—
Other gas purchases – Trade – Spot	242	225	—	—	—	—
Transmission charges and other expenses	285	237	—	—	—	—
Allocation to/from domestic energy	26	126	65	2,412	79.08	56.04
<b>Total Trade</b>	<b>\$ 1,157</b>	<b>\$ 1,109</b>	<b>50,948</b>	<b>51,371</b>	<b>\$ 44.61</b>	<b>\$ 47.24</b>
<b>Total Energy Costs</b>	<b>\$ 2,393</b>	<b>\$ 2,057</b>	<b>109,053</b>	<b>111,176</b>	<b>\$ 32.17</b>	<b>\$ 30.35</b>

<sup>1</sup> Other electricity purchases in dollars include purchases for trade activities shown net of derivatives. Gigawatt hours and \$ per MWh are shown at gross cost.

<sup>2</sup> Total cost per MWh includes other electricity purchases at gross cost.

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For the year ended March 31, 2009, total energy costs of \$2,393 million were \$336 million or 16.3 per cent higher than the previous year primarily as a result of lower hydro generation due to lower inflows and system constraints which required higher electricity purchases from Independent Power Producers (IPPs) and other long-term contracts, higher market electricity purchase volumes, higher gas trade volumes and prices, and higher electricity trade spot purchases.

### DOMESTIC ENERGY COSTS

Domestic energy costs for the year ended March 31, 2009 were \$288 million or 30 per cent higher than the previous year. The increase was due to higher purchases of energy as opposed to low-cost hydro generation. Higher purchase volumes from all sources were required due to lower than average inflows and system constraints such as the GM Shrum Generating Station unit outage, while contango pricing in the second half of fiscal 2009 motivated pre-purchasing of market electricity. In addition, prices from IPPs were higher than in the prior year.

### TRADE ENERGY COSTS

Trade energy costs for the year ended March 31, 2009 increased by \$48 million over the prior year primarily due to trade electricity and remarketed gas purchases. The increase in trade electricity purchases includes a decrease in forward electricity purchases of \$266 million, which are netted in revenue in accordance with GAAP, offset by an \$83 million increase in spot electricity purchases. Gross electricity purchases for the year reflect marginal decreases in average electricity purchase prices and in electricity purchase volumes. The increase in remarketed gas purchases of \$299 million was driven by a 26 per cent increase in gross gas purchase volumes and an 8 per cent increase in the average gross gas purchase price. As with gas sales, gas purchase volume increases reflect Powerex's strategy to grow its gas business while increased gas purchase prices were due to supply concerns in the early part of the year.

### WATER INFLOWS

Water inflows into BC Hydro's reservoirs were 96 per cent of average in fiscal 2009, compared to 114 per cent of average in fiscal 2008 (average is based on the 1971-2000 period). This resulted in a decrease in the volume of low-cost hydro generation, one factor influencing the level of energy purchases. The decision to purchase energy instead of utilizing hydro generation is based on many factors, such as the forecast market price of energy in future periods relative to the current period, current reservoir levels and future demand requirements. Operating constraints related to legal and regulatory obligations such as minimum reservoir levels and stream flow requirements also affect the decision to import energy.

The BC Hydro reservoirs have been managed such that the combined storage in BC Hydro reservoirs at March 31, 2009 was 115 per cent of average, compared to 106 per cent of average at March 31, 2008 (average storage levels relate to the average from 1986-2008), with the Williston reservoir on the Peace River system at 106 per cent of average (fiscal 2008 - 114 per cent), and the Kinbasket reservoir on the Columbia River system at 147 per cent of average (fiscal 2008 - 79 per cent).

### OPERATING COSTS

Operations costs for the year ended March 31, 2009, were \$123 million lower than the previous year. The decrease from fiscal 2008 was primarily due to \$229 million in provisions made in fiscal 2008 for First Nations settlement costs, partially offset by higher Site C costs in fiscal 2009 as this project moved into its second phase, and higher demand-side management (DSM) costs which supports energy conservation. All of these costs are transferred to regulatory accounts and do not impact current year net income. Excluding the costs that were transferred to regulatory accounts, operations costs were \$28 million higher than the prior year, largely due to a \$19 million increase in provisions for California litigation matters and higher expenditures on engineering and supply chain management.

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Maintenance costs for the year ended March 31, 2009, were \$61 million higher than the previous year. The increase was primarily the result of unexpected expenditures to address equipment failures of a unit at the GM Shrum Generating Station near the Peace River which occurred in the first quarter, increased maintenance of distribution assets, routine vegetation work to improve system resiliency for the storm season, expenditures for penstock coatings, increased civil maintenance and facility repairs in fiscal 2009. The GM Shrum turbine failure resulted in significant unplanned major maintenance and costs are therefore transferred to a new deferral account, the GM Shrum Unit 3 Outage regulatory account.

General and administrative costs were \$35 million higher than the previous year. The increase is primarily the result of expenditures for the Smart Metering and Infrastructure project (SMI), procurement enhancement initiative and information technology initiatives. Excluding the costs that were transferred to regulatory accounts, general and administrative costs were \$19 million higher than the prior year, largely due to information technology, strategic procurement and employee-related costs.

## AMORTIZATION EXPENSE

Amortization expense for the year ended March 31, 2009, was \$26 million higher than the previous year mainly due to the one time gain on the sale of a compressor that occurred in fiscal 2008 which was credited to and decreased amortization expense for the 2008 year, and increased assets in service. This increase was partially offset by gains from the sale of land in fiscal 2009, fewer project write-offs, and lower contributions in aid assets in service.

## FINANCE CHARGES

Finance charges for the year ended March 31, 2009, were \$9 million higher than the previous year. The increase is due to foreign exchange translation losses on net unhedged US dollar debt as a result of the weakening of the Canadian dollar as compared to the US dollar in the current year versus the strengthening of the Canadian dollar as compared to the US dollar in the prior year, a higher average volume of debt, and lower sinking fund income as the Canadian sinking funds were liquidated in June 2008. These negative variances were partially offset by lower short-term interest rates and higher capitalized interest related to higher capital expenditures.

## RETURN ON EQUITY AND PAYMENT TO THE PROVINCE

<i>(dollar amounts in millions)</i>	2009	2008
Actual return on equity <sup>1</sup>	11.75%	11.33%
Allowed return on equity <sup>2</sup>	11.78%	12.05%
Payment to the Province	—	\$ 288

<sup>1</sup> Based on equity as defined for regulatory purposes, which changed by Order in Council from the Province effective April 1, 2008.

<sup>2</sup> BC Hydro's allowed return on equity for F08 and F09 were set by the Commission via BCUC Orders G-143-06 dated November 10, 2006 and G-16-09 dated March 13, 2009 respectively. The allowed return on equity has been calculated to equal, on a pre-income tax basis, that of the most comparable investor-owned utility.

Under a Special Directive from the Province, BC Hydro is required to make an annual Payment to the Province (the Payment) on or before June 30 of each year. The Payment is equal to 85 per cent of BC Hydro's distributable surplus for the most recently completed fiscal year assuming that the debt to equity ratio, as defined by the Province, after deducting the Payment, is not greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment will be based on the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. Due to the 80:20 cap, no Payment is payable for fiscal 2009.

## FINANCIAL RESULTS

The definition of equity to determine the debt to equity ratio for purposes of calculating the Payment, is determined through an Order in Council from the Province. On January 17, 2008, the Province changed the definition of equity to include only retained earnings and accumulated other comprehensive income. This change was effective for fiscal years beginning April 1, 2008. Prior to this change, equity was defined as the sum of retained earnings, deferred revenue, contributions arising from the Columbia River Treaty and contributions in aid of construction.

## LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the year ended March 31, 2009, was \$254 million, compared with \$836 million for the prior year. The primary reasons that cash flow provided by operating activities decreased in fiscal 2009 are higher purchased cost of energy and net increases in working capital.

The net long-term debt balance at March 31, 2009, was \$9,325 million, compared with \$7,541 million at March 31, 2008. The increase was mainly as a result of net long-term bond issues totaling \$258 million, an increase in revolving borrowings of \$695 million, an increase of \$66 million in debt due to fair value hedge accounting, net foreign exchange revaluation losses of \$273 million and withdrawals of \$509 million in sinking funds. The funds generated in the current year were used primarily to fund property, plant and equipment expenditures and the 2008 Payment to the Province.

The net short-term debt balance at March 31, 2009, was \$2,331 million, compared with \$1,090 million at March 31, 2008. The increase over the prior year was mainly due to an increase in revolving borrowings of \$695 million and an increase in the current portion of long-term debt due to mature in the next fiscal year (\$640 million) compared with the previous year (\$94 million).

## PROPERTY, PLANT AND EQUIPMENT EXPENDITURES

Property, plant and equipment expenditures were as follows:

<i>(in millions)</i>	2009	2008	Increase
Distribution improvements and expansion	\$ 399	\$ 357	\$ 42
Generation replacements and expansion	349	287	62
Transmission lines and substation replacements & expansion <sup>1</sup>	474	284	190
General, including computers and vehicles <sup>2</sup>	178	148	30
<b>Total Property, Plant and Equipment Expenditures<sup>3</sup></b>	<b>\$ 1,400</b>	<b>\$ 1,076</b>	<b>\$ 324</b>

<sup>1</sup> Fiscal 2008 restated for inventory reclassified to Property, Plant and Equipment per new accounting standard CICA Section 3031.

<sup>2</sup> Reclassification of Land Rights to General.

<sup>3</sup> Includes Intangible Assets.

For the year ended March 31, 2009, the increase in distribution improvements and expansion is primarily due to increased spending on reinforcement and substation expansion projects and increased system improvement work. The increase in generation replacements and expansion is mainly as a result of increased spending on the Revelstoke Unit 5 installation, the Ruskin Powerhouse and dam project, and the Cheakamus Spillway Gate Reliability project. These increases are partially offset by lower spending on the John Hart Spillway Gate Reliability project. The increase in transmission activity is mainly due to higher expenditures on the Vancouver Island Transmission Reinforcement project, the Interior to Lower Mainland project, the Mission and Matsqui project and various IPP projects. These increases are partially offset by lower expenditures on the Terasen TMPSE project, and the Gibraltar Mine Load Increase. The increase in general capital expenditures is primarily due to a greater number of information technology projects and vehicle purchases.

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### DERIVATIVE FINANCIAL INSTRUMENT ASSETS AND LIABILITIES

All derivative financial instruments are required to be carried on the balance sheet at fair value. As at March 31, 2009, BC Hydro recorded a net derivative financial instrument asset of \$95 million (\$1,167 million asset less \$1,072 million liability) compared with a net financial instrument liability of \$81 million (\$729 million asset less \$810 million liability) in the prior year. The weakening of the Canadian dollar in the current year resulted in significant gains in foreign currency contracts as compared to the prior year.

### COMPARISON WITH SERVICE PLAN

The *Budget Transparency and Accountability Act* requires that BC Hydro file a Service Plan each February. BC Hydro's Service Plan filed in February 2008 forecast income before regulatory accounts for fiscal 2009 at \$247 million and net income forecast at \$358 million. BC Hydro prepared an updated forecast in January 2009 that forecast income before regulatory accounts of \$3 million and net income at \$357 million (See Future Outlook).

Actual loss before regulatory account transfers for the year ended March 31, 2009, was \$72 million, which was \$319 million lower than the February 2008 Service Plan forecast of income of \$247 million. This is primarily the result of lower than forecast domestic gross margin due to lower domestic revenues, particularly in the large industrial sector which was impacted by weakness in the forestry sector of the economy, and to higher costs for energy purchases due to lower than average water inflows and unexpected outages which reduced generation levels during the year.

Net trade margins were higher than the February 2008 Service Plan forecast largely due to favourable electricity price spreads between the Northwest and Southwest in the first half of the year as a result of freshet occurring later than normal and between the Northwest and Alberta in the second half of the year driven by generation outages in Alberta.

Operating costs increased by \$75 million from the February 2008 Service Plan due to an increase in the provision for California litigation matters, unexpected expenditures to address equipment failures of a unit at the GM Shrum Generating Station, higher Site C costs and expenditures on SMI, and higher routine and storm restoration costs incurred during the winter season. Amortization expense is \$5 million lower than the February 2008 Service Plan due to the gain on sale of assets and fewer assets in service than planned for the year.

The majority of these impacts to net income are transferred to regulatory accounts. As a result, the actual net income of \$366 million was \$8 million higher than the February 2008 Service Plan.

## FINANCIAL RESULTS

The table below provides an overview of BC Hydro's financial performance relative to its 2009 to 2011 Service Plan Update (February 2008). The results and forecasts form the basis upon which key performance targets are set.

	Actual			Service Plan	2009
	2007	2008	2009	Forecast	Variance
<i>(in millions)</i>					
<b>Revenues</b>					
Total Domestic	\$ 2,786	\$ 2,944	\$ 2,814	\$ 3,136	\$ (322)
Trade	1,406	1,266	1,455	2,021	(566)
	4,192	4,210	4,269	5,157	(888)
<b>Expenses</b>					
Energy costs	2,117	2,057	2,393	3,007	614
Operating costs	716	942	915	840	(75)
Taxes	149	153	167	167	—
Amortization	378	368	394	399	5
	3,360	3,520	3,869	4,413	544
<b>Operating Income</b>	832	690	400	744	(344)
Finance Charges	453	463	472	497	25
<b>Income Before Regulatory Account Transfers</b>	379	227	(72)	247	(319)
Net Change in Regulatory Accounts	28	142	438	111	327
<b>Net Income</b>	\$ 407	\$ 369	\$ 366	\$ 358	\$ 8

## CHANGE IN ACCOUNTING POLICY AND ADOPTION OF NEW ACCOUNTING STANDARDS

### CHANGE IN ACCOUNTING POLICY

BC Hydro's subsidiary Powerex has elected to change its accounting policy for recording revenues and related costs for physical derivative natural gas transactions. Under the previous accounting policy, settlements of derivative financial instruments involving the sale or purchase of physical natural gas was reported on a gross basis in the income statement as sales and cost of energy, respectively. As these contracts are considered derivative financial instruments, Powerex has determined it is more representative to present the revenues and related costs on a net basis upon settlement.

Prior year balances have been revised to conform with the new policy, resulting in a decrease in trade revenue and trade energy costs of \$644 million. There was no impact on net income and therefore, no opening retained earnings.

### ACCOUNTING STANDARDS ADOPTED IN 2009

Effective April 1, 2008, BC Hydro adopted four new Canadian Institute of Chartered Accountants (CICA) accounting standards: (a) Section 1535, Capital Disclosures; (b) Section 3031, *Inventories*; and (c) Section 3862, *Financial Instruments – Disclosures* and Section 3863, *Financial Instruments – Presentation*. The main requirements of these new standards and the resulting financial statement impact are described below.

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### (a) Capital Disclosures

CICA Section 1535 requires disclosure of: (i) an entity's objectives, policies and process for managing capital; (ii) quantitative data about what the entity considers as capital; and (iii) whether the entity has complied with any capital requirements and, if it has not complied, the consequences of such non-compliance. Refer to Note 6 in the consolidated financial statements for additional disclosures.

### (b) Inventories

CICA Section 3031 provides significantly more guidance on the measurement of inventories, with an expanded definition of cost and the requirement that inventory must be measured at the lower of cost and net realizable value. In addition the section has additional disclosure requirements, including accounting policies, carrying values, and the amount of any inventory write-downs. Refer to Note 4 in the consolidated financial statements for additional disclosures.

### (c) Financial Instruments – Disclosures and Financial Instruments – Presentation

CICA Section 3862, *Financial Instruments – Disclosures* and Section 3863, *Financial Instruments – Presentation* replace Handbook Section 3861, *Financial Instruments – Disclosure and Presentation*, revising and enhancing its disclosure requirements, and carrying forward unchanged its presentation requirements. These new sections place increased emphasis on disclosures about the nature and extent of risks arising from financial instruments and how the entity manages those risks. The incremental disclosures required as a result of adopting these Sections can be found in Note 13 in the consolidated financial statements. The transitional provisions provide that certain of the incremental disclosures need not be provided on a comparative basis in the year of adoption.

### (d) Credit Risk and the Fair Value of Financial Assets and Liabilities

In January 2009, the CICA Emerging Issues Committee ("EIC") issued EIC-173, *Credit Risk and the Fair Value of Financial Assets and Liabilities*. EIC-173 is effective for interim and annual financial statements ending on or after January 20, 2009. EIC-173 provides guidance that an entity's own credit risk and the credit risk of counterparties should be taken into account in determining the fair value of financial assets and liabilities. Adoption of this guidance is applied retrospectively without restatement of prior periods. For the year ended March 31, 2009, the revaluation of financial assets and liabilities resulted in a decrease in Net Income and Other Comprehensive Income of \$13 million and \$25 million, respectively. The adjustment to the April 1, 2008 opening balances for retrospective application of impacts prior to 2009 had no material effect on either opening Retained Earnings and Accumulated Other Comprehensive Income.

## FUTURE ACCOUNTING CHANGES

### (a) International Financial Reporting Standards

In February 2008, the Canadian Accounting Standards Board (AcSB) confirmed that the use of IFRS will be required in 2011 for publicly accountable enterprises. IFRS will replace Canada's current Generally Accepted Accounting Principles (GAAP) for those enterprises. These include profit-oriented enterprises that are responsible to large or diverse groups of stakeholders, including government business enterprises, which would include crown corporations such as BC Hydro. The official changeover date is for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. The Company is currently evaluating the impact of the transition to IFRS on its consolidated financial statements.

### (b) Goodwill and Intangible Assets

Effective April 1, 2009, the Company will adopt new CICA Handbook Section 3064, *Goodwill and Intangible Assets*. This section replaces CICA Handbook Section 3062, *Goodwill and Intangible Assets*, and establishes revised standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets. It is anticipated that these changes will not have a material impact on the Company's consolidated financial statements.

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### (c) Accounting for Rate-Regulated Operations

In August 2007, the AcSB considered the comments received on its March 2007 Exposure Draft, "Rate-Regulated Operations," and decided to: (i) remove the temporary exemption in Section 1100, *Generally Accepted Accounting Principles*, pertaining to the application of that Section to the recognition and measurement of assets and liabilities arising from rate regulation; (ii) not withdraw from the Handbook all other recognition and measurement guidance relating specifically to rate-regulated operations; and (iii) retain AcG-19, *Disclosures by Entities Subject to Rate Regulation*, but to make consequential amendments to the Guideline as a result of the above changes. The changes are applicable prospectively to BC Hydro's fiscal year beginning on April 1, 2009. It is anticipated that these changes will not have a material impact on the Company's regulatory accounting practices.

## STATUS OF TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

On February 13, 2008, the Canadian Accounting Standards Board confirmed the adoption of IFRS in place of Canadian GAAP for publicly accountable enterprises. The new requirements are effective for interim and annual reporting periods beginning on or after January 1, 2011. For BC Hydro, this will be effective for the fiscal year commencing on April 1, 2011.

To facilitate the conversion process, BC Hydro has appointed an external advisor and assembled a core project team. Project governance has been established with the formation of a Steering Committee and the identification of other key stakeholders within the organization who will support the overall conversion process. Regular reporting is provided to the Audit and Risk Management Committee of the Board of Directors.

Project planning commenced with a high level diagnostic review of significant differences between IFRS and Canadian GAAP. Areas with significant differences that will impact BC Hydro include: Regulatory Accounting, Property, Plant & Equipment, Provisions and Contingent Liabilities, Employee Benefits, and the overall presentation of financial statements. There are also a number of significant changes with the initial adoption of IFRS under IFRS 1, First-time Adoption of International Financial Reporting Standards.

Planning efforts have advanced on potential changes to Regulatory Accounting and related impacts to financial reporting for rate making purposes. Collaboration with the BCUC will be integral throughout this process. An industry work group of B.C. regulated utilities was also established during the year to identify common transition issues and potential regulatory strategies to address them.

Diagnostic and assessment activities have been substantially completed to date. The completion of topic specific workshops resulted in detailed assessments of potential impacts along with required changes to policies, processes and systems. An analysis of financial system impacts has been completed and specific reporting requirements have been incorporated into the planned conversion to a new financial system platform. Implementation activities will begin in earnest commencing in fiscal 2010.

## REGULATION

### REGULATORY ACCOUNTS

BC Hydro has established various regulatory accounts with the approval of the BCUC. Regulatory accounts allow BC Hydro to defer certain types of revenue and cost variances through transfers to and from the accounts which has the effect of adjusting net income. The deferred amounts are then included in customer rates in future periods, subject to approval by the BCUC.

For the year ended March 31, 2009, BC Hydro transferred, on a net basis, \$438 million of costs to regulatory accounts compared with

## FINANCIAL RESULTS

\$142 million during the previous year. The majority of the transfers relate to the cost of energy deferral to the Heritage Deferral Account (HDA) and demand-side management expenditures. The net balance of the regulatory asset and liability accounts as at March 31, 2009, was a \$1,016 million asset compared to a \$ 572 million asset at March 31, 2008. The significant increase in transfers to the cost of energy deferral accounts primarily reflects the higher than planned cost of energy in the current year compared with fiscal 2008 as a result of the requirement to purchase higher levels of energy in the market in order to meet domestic load requirements. The net balance in the deferral accounts (HDA, Non-Heritage Deferral Account (NHDA), Trade Income Deferral Account (TIDA) and BCTC Deferral Account (BCTCDA)) as at March 31, 2009, was a \$332 million asset compared to a \$48 million asset as at March 31, 2008. The energy deferral accounts are recovered through the rate rider.

The HDA and NHDA are referred to as the cost of energy deferral accounts because they are designed to defer the variance between the actual cost incurred by BC Hydro for energy supplied and the forecast energy cost in the most recent revenue requirements application. As a result of significant system energy constraints and lower inflows experienced in the current year (96 per cent of average), hydro generation was 4,802 GWh lower than forecast at the beginning of the fiscal year, resulting in higher market purchases required for domestic consumption. The average cost of hydro generation is \$7.07 per MWh compared to the average cost of \$53.98 per MWh for market purchases for the year ended March 31, 2009.

## REVENUE REQUIREMENTS APPLICATION

In regulating and setting rates for BC Hydro, the BCUC must ensure that the rates are sufficient to allow BC Hydro to provide reliable electricity service, meet its financial obligations, comply with government policy and achieve an annual rate of return on equity based on forecast consolidated net income. The annual rate of return on equity is equal to the pre-income tax annual rate of return allowed by the BCUC to the most comparable investor-owned energy utility regulated under the *Utilities Commission Act*. The allowed annual rate of return on equity calculated based on equity as defined for regulatory purposes for fiscal 2009 was 11.78 per cent (2008 – 12.05 per cent). The actual rate of return in fiscal 2009 was 11.75 per cent. The allowed annual rate of return for fiscal 2010 is estimated at 13.05 per cent.

BC Hydro filed its F2009/2010 Revenue Requirements Application (RRA), with the BCUC on February 20, 2008 and the BCUC issued its decision on March 13, 2009, approving rate increases of 2.34 per cent as of April 1, 2008 and 8.74 per cent as of April 1, 2009. Rate riders of 0.5 per cent for fiscal 2009 and 1 per cent for fiscal 2010 to recover the balances in the deferral accounts were also approved. The approved rate increase of 2.34 per cent is lower than the interim rate increase of 6.56 per cent. BCUC has directed BC Hydro to refund the difference to its customers, including interest. Recovery of deferral account balances as approved by the BCUC from the approved rate rider in fiscal 2009 was \$14 million.

In addition to the decision on rates, the BCUC also directed that several new regulatory accounts be created for the purpose of deferring certain revenue and cost variances and adjusting net income. Commencing in fiscal 2009, the new regulatory accounts include the GMS3 Regulatory Account to provide for the deferral of costs for the GM Shrum Unit 3 outage and regulatory accounts to capture variances between actual and planned expenditures for finance charges, taxes, amortization of capital additions, storm costs and net employment costs included in operating costs. Commencing in fiscal 2010, two additional new regulatory accounts will be added. One is to capture variances between actual and planned non-current pension costs, and the other is to defer in the Return on Equity Adjustment Regulatory Account the impact of the amendment to Heritage Special Direction No. HC2 of February 17, 2009 which added 1.63 per cent to BC Hydro's allowed annual rate of return on equity for fiscal years 2010, 2011 and 2012.

## FINANCIAL RESULTS

### RATE DESIGN

BC Hydro filed a Residential Inclining Block Rate (RIB) application on February 26, 2008. It proposed a two-step rate structure for residential customers, with the Step-2 rate price for all energy consumption over a certain kWh amount per bi-monthly billing period. The BCUC approved the two-step RIB rate effective October 1, 2008, setting the Step 1 threshold at 1,350 kWh and capping the Step 2 rate at BC Hydro's long-run cost of supply.

The Step 2 rate is intended to better reflect the long-run cost of new energy supply and to provide an effective price signal to encourage energy conservation and efficiency. While the rate is designed to be revenue neutral to the residential rate class, individual customers will see bill impacts, which can be mitigated through consumption behaviour changes and participation in BC Hydro's Power Smart programs.

### LONG-TERM ACQUISITION PLAN

On June 12, 2008, BC Hydro filed the 2008 Long-Term Acquisition Plan (LTAP) Application with the BCUC. The 2008 LTAP is an update to the 2006 Integrated Electricity Plan/LTAP and outlines actions to be taken over the next 10 years to build on work started to meet the 2007 British Columbia Energy Plan's objectives and ensure that BC Hydro continues to provide reliable, cost-effective long-term service to its customers. A public hearing took place in February 2009, and a decision by the BCUC is expected in the summer of 2009.

### STANDING OFFER PROGRAM

The Standing Offer Program (SOP) establishes a standing offer for power produced from clean electricity projects up to 10 megawatts, and is in accordance with the policy action in the Provincial Government's 2007 Energy Plan. A negotiated settlement on the terms and conditions of this program was reached with BC Hydro's customer groups and stakeholders and approved by the BCUC in March 2008. During fiscal 2009, BC Hydro received and applied the SOP rules to nine applications and signed one SOP Electricity Purchase Agreement.

### BIO-ENERGY CALL (PHASE 1)

BC Hydro issued its Phase 1 Request for Proposals in late fiscal 2008. After an extensive review process of the 20 proposals received, four Electricity Purchase Agreements (EPAs) were awarded in December 2008 for 579 GWh/year of firm energy and 60 MW of dependable capacity. The awards are consistent with a number of policy actions directed by government in the 2007 Energy Plan. These EPAs were filed with the BCUC on February 17, 2009 and are currently being reviewed.

### HOME PURCHASE OFFER PROGRAM

BC Hydro is carrying out a Home Purchase Offer Program (HPOP) for owners of certain residential properties located on BC Hydro's transmission right of way corridor located between Tsawwassen Substation and English Bluff Terminal Station. Purchase agreements for 104 properties totaling approximately \$62 million have been finalized and purchases are planned to be concluded by the end of September 2009. HPOP net costs will be recorded in a regulatory account per Direction No. 1 to the BCUC dated March 12, 2009 and will be recovered in future rates.

## FINANCIAL RESULTS

### LEGAL PROCEEDINGS

Since 2000, Powerex has been named, along with other energy providers, in lawsuits and U.S. federal regulatory proceedings which seek damages and/or contract rescissions based on allegations that, during part of 2000 and 2001, the California wholesale electricity markets were unlawfully manipulated and energy prices were not just and reasonable. Powerex has obtained dismissals of all but one of the lawsuits. In the remaining lawsuit, the California Department of Water Resources (CDWR) has claimed that it was forced under duress to enter into numerous transactions with Powerex in 2001. The trial in the CDWR litigation is scheduled to begin on May 18, 2010 in federal court. If CDWR is successful at trial the case will then go to the Federal Energy Regulatory Commission (FERC) to determine appropriate remedies.

FERC has approved a settlement agreement between FERC staff and Powerex that acknowledged that there was no evidence that Powerex engaged in any gaming or other improper practices with any other market participants, and further noted that Powerex was a valuable and reliable supplier to the California market throughout the energy crisis. FERC's approval of this settlement is currently being challenged by various California parties. If the challenges are unsuccessful, FERC's determination that Powerex did not engage in market manipulation will stand and could provide Powerex with additional defences in the remaining litigation and other FERC proceedings.

FERC decided earlier in the proceedings that certain market-wide refunds will have to be paid by energy providers to various California parties. The precise amount has not been determined and the timing of the refunds is unknown. In addition, FERC has been ordered by the Ninth Circuit to reconsider additional refunds based on allegations of seller market manipulation and on quarterly reporting deficiencies. CDWR transactions will be included in these latter inquiries.

At March 31, 2009, Powerex was owed US \$263 million (CDN \$332 million) by the California Power Exchange (Cal Px) and the California Independent System Operator (CAISO) related to Powerex's electricity trade activities in California during the period covered by the lawsuits. As a result of defaults by a number of California utilities, the Cal Px and CAISO were unable to pay these amounts to Powerex. It is expected those receivables will be offset against any refunds that Powerex is required to pay.

Due to the ongoing nature of the regulatory and legal proceedings against Powerex, management cannot predict the outcomes of the claims against Powerex. Powerex has recorded provisions for uncollectible amounts and legal costs associated with the California energy crisis. These provisions are based on management's best estimates, and are intended to adequately provide for any exposure. However, the amounts that are ultimately collected or paid may differ from management's current estimates. Management has not disclosed the provision amounts or ranges of expected outcomes due to the potentially adverse effect on the process. Due to the size, complexity and nature of BC Hydro's operations, various other legal matters are pending. It is not possible at this time to predict with any certainty the outcome of such litigation. Management believes that any settlements related to these matters will not have a material effect on BC Hydro's consolidated financial position or results of operations.

### RISK MANAGEMENT

BC Hydro's operations involve a broad spectrum of risks ranging from those commonly associated with any business to catastrophic societal loss risks that would have severe effects on entire regions. The key risks BC Hydro faces are divided into six categories for management purposes: employee, public and dam safety; reliability; financial performance; regulatory; organization risk; and environmental.

## FINANCIAL RESULTS

### EMPLOYEE, PUBLIC AND DAM SAFETY

Safety risks to the public exist due to the multiple uses of water for electricity generation, recreation and waterways. Risks can also result from potential contact with transmission and distribution equipment located in communities. To manage the public safety risk, BC Hydro relies on design, construction and operating standards and practices, signage, consultation with other agencies and stakeholder groups, and public education. BC Hydro also prepares emergency response plans to limit injury and loss of life and to restore electric service.

Many of BC Hydro's employees face the risk of serious injury or death by the nature of their jobs in dealing with electrical and other high risk hazards. To mitigate these inherent risks, BC Hydro has a comprehensive safety management system that includes employee involvement, communication, training, resources, policies and safety practice regulations.

The large dams represent a catastrophic loss risk (low probability but high consequence) to BC Hydro in terms of life, safety, financial, environmental and reputation. This dam failure risk is managed through a comprehensive dam safety management system involving dam safety professionals and experts. The system incorporates dam surveillance and monitoring, periodic independent reviews of dam performance, dam investigations and analysis. Dam upgrades may be required due to changes in knowledge, standards or extreme event parameters (for earthquake, floods, landslides). BC Hydro follows the B.C. Dam Safety Regulation, participates in the Canadian Dam Association and the International Commission on Large Dams, and engages panels of international experts for independent advice on the management and control of these risks.

### RELIABILITY

The most significant risk to the reliability of BC Hydro's system is the impact of weather. With BC Hydro's large service territory, there is significant exposure to trees, terrain and diverse weather patterns. BC Hydro mitigates the likelihood and consequence of such impacts through effective design, construction, operations, maintenance and response. Additionally, a five-year System Resiliency Program is in progress which increases the ability of the system to withstand interruptions caused by adverse weather. In managing these risks, BC Hydro balances customers' expectations and cost considerations. Reliability risks could also result from either a lack of available generation supply or the associated transmission capacity to meet customer demand. BC Hydro manages these risks through long-term planning, asset maintenance programs, reliance on a diverse supply of energy options, and through cooperative support arrangements with neighbouring utilities.

BC Hydro must meet government permitting requirements to operate its facilities and build new infrastructure, which can have an impact on project lead times. Delays in obtaining appropriate permits and consent could adversely impact reliability.

### FINANCIAL PERFORMANCE

In meeting its financial performance targets, BC Hydro faces many risks including energy costs, energy demand, interest and foreign exchange rates, pension obligations, and energy trading. Of these, risks associated with energy costs – specifically water inflows and energy market prices – are the largest. BC Hydro is permitted to earn an allowed return on equity. Tariff rates are set based upon BC Hydro's cost and equity forecast. Many risks (difference between forecast and actual costs) associated with uncontrollable costs are mitigated through regulatory deferral accounts. The major cost components susceptible to variation included in the regulatory deferral accounts are water inflows, energy prices including thermal fuel costs, and trade income.

## FINANCIAL RESULTS

Increasing costs due to aging infrastructure, the need for new supply and the need to manage environmental impacts create challenges for BC Hydro in maintaining the low electricity cost advantage the province enjoys. How BC Hydro manages tradeoffs between these competing objectives will be important to its financial performance and its ability to make the required infrastructure investment. External long-term costs of environmental and social impacts need to be factored into decision-making today to ensure the right business decisions are made for the long-term.

Based on recent financial market volatility, market returns on the pension plan assets are expected to be significantly lower than originally forecast. The return on pension fund assets has a significant impact on employee future benefit costs. The total impact on costs has not been determined but could be significant for fiscal 2010.

## CREDIT RISK

The recent volatile economic and market conditions could further impact customer loads and the creditworthiness of customers and suppliers and could limit energy trading opportunities.

## ENERGY COST

Energy cost risk is the most significant financial risk to BC Hydro. It arises when BC Hydro is required to purchase electricity from the markets due to increased electricity demand in B.C. or lower-than-expected water inflow levels. It can also result from changing market prices for electricity and natural gas. Overall BC Hydro system inflows during fiscal 2009 were slightly below average, primarily in the Columbia River system. As a result, in 2009 BC Hydro was a net buyer of market electricity for the eighth year in the last nine years.

The outlook for fiscal 2010 is for another below-average system inflow year, and BC Hydro again expects to be a net buyer of market electricity. BC Hydro manages energy cost risk through its flexible hydroelectric system, which allows water to be stored in large reservoirs and used when it is most economic, and by hedging the cost of imported electricity. This risk is also mitigated through regulatory deferral accounts which allow BC Hydro to recover its energy costs in rates provided they have been prudently incurred.

## ENERGY DEMAND

Electricity demand is increasing as B.C.'s population increases and its economy grows. However, this demand can be volatile, particularly from larger customers whose consumption is often driven by export markets and world commodity prices. BC Hydro's risk mitigation strategy is to achieve energy security from domestic sources. BC Hydro's first and best choice for energy security is through energy conservation and efficiency. Additional choices include reinvesting in assets to prolong their life, and where possible, adding additional energy and capacity. BC Hydro is also examining the potential of new hydro generation facilities and will continue to purchase clean and renewable power from IPPs.

## INTEREST RATES AND FOREIGN EXCHANGE RATES

Changes in interest and foreign exchange rates can significantly impact BC Hydro's finance charges. BC Hydro debt-management strategies include limiting the allowable percentage range of variable interest rate debt, and closely monitoring settlement and counterparty credit risks associated with derivative financial instruments. Interest and foreign exchange rate changes can also influence the performance and cost of BC Hydro's employee benefit and pension plans.

## FINANCIAL RESULTS

At March 31, 2009, \$2,881 million or 32.5 per cent of net debt, as defined by BC Hydro's Liability Risk Management Policy, was subject to interest rate reset within the next fiscal year. Interest rate risk is managed within Board approved limits and policies, which require the debt portfolio to be managed using an appropriate blend of fixed and floating rate debt, as well as by managing the term to maturity of its debt portfolio to manage exposure to interest rate movements in the future. BC Hydro utilizes financial instruments, including interest rate swaps and options, to adjust the balance of fixed and floating rate debt, and to reduce its overall cost of borrowing.

Falling interest rates resulting from the global financial turmoil have allowed BC Hydro to take advantage of the low rates for long-term debt to increase our proportion of long-term fixed rate debt and reduce our floating interest rate exposure.

BC Hydro is exposed to exchange rate risk through the purchase of U.S. dollar priced electricity and natural gas, from Powerex through its U.S. trade activities, from U.S. dollar capital equipment purchases and from U.S. dollar debt servicing. Foreign exchange risk is managed within Board approved limits and policies. Both foreign exchange and interest rate risks are monitored and reported on a monthly basis.

Commencing in fiscal 2009, variances between actual and planned finance charges, exclusive of Powerex, are deferred to a new regulatory account and therefore do not impact current year net income.

## ENERGY TRADING

BC Hydro's energy trading subsidiary, Powerex, is exposed to the risk of variable market prices and counterparties who might not meet their obligations. Powerex manages these risks by operating through defined limits that are regularly reviewed by both the Powerex and BC Hydro Boards of Directors. Powerex primarily focuses on near-mid-term trading positions, backing forward commitments with the physical supply capability of the BC Hydro System, the Canadian Entitlement, and other supply contracts, while operating within Board approved market and credit limits. Longer-term positions are reviewed in the context of the overall energy trading portfolio.

Powerex is exposed to the risk of litigation, such as the potential liabilities from the California power crisis. The conduct of Powerex employees is governed by its Trading Code of Conduct and Compliance policies and procedures. Powerex also adheres to the Electric Power Supply Association's Code of Ethics and Sound Trading Practices for Electric Power Suppliers to guide its trading activities.

## REGULATORY RISK

BC Hydro's proposals on revenue requirements, rate designs, long term planning, power procurement, and major capital projects are subject to review and approval or acceptance by BCUC. Depending on the outcome of these reviews, BC Hydro may not be able to undertake some of these initiatives or certain costs incurred by BC Hydro may not be recoverable in rates. Adding to this prevalence of regulatory uncertainty is the impact of the current economic downturn on BC Hydro's revenues and costs. The BCUC recently established a number of regulatory accounts to deal with this near-term economic uncertainty and lessen the financial risk to BC Hydro.

BC Hydro manages this regulatory risk by working to maintain positive relationships with its intervenors, stakeholders and the BCUC and ensures that its proposals and applications are well-justified and in the interests of its ratepayers.

## FINANCIAL RESULTS

### ORGANIZATIONAL RISK

Ensuring the appropriate supply of labour in both the short and long-term is a challenging issue for BC Hydro as well as for other utilities and businesses across North America. While the current global economic slowdown has eased some of the pressures within the external labour market and improved the attraction and retention of our workforce, certain occupation groups such as technical workers, operational managers and qualified trades people remain in limited supply across the local and broader employment marketplace. The cost of living in many British Columbia communities continues to pose a challenge to the attraction and retention of employees as does the geographic isolation of some BC Hydro work locations. A moderately reduced attrition rate has also kept BC Hydro's retirement eligibility rate high with around 25 per cent of our current staff eligible to retire within the next 5 years. Failing to maintain and develop BC Hydro's people capacity presents risk to the ability to execute our operational and capital plans.

### ENVIRONMENTAL AND SOCIAL PERFORMANCE

BC Hydro's environmental responsibility policy states that BC Hydro will meet or exceed environmental regulations defined by legislation, regulation, government directives and guidelines, as well as its commitments and agreements. Even if there is no environmental or social regulation, BC Hydro can face risks. These risks are managed through voluntary activities, such as the Water Use Plans. Voluntary action is taken with a view to managing long-term risk and for cost controls.

Areas where BC Hydro is exposed to the risk of non-compliance with environmental regulations include the release of hazardous materials into the environment, endangerment of wildlife and their habitats, or damage to heritage sites where there is evidence of historic human occupation. These risks are managed through environmental management systems and risk mitigation strategies.

BC Hydro's Board approved a corporate social responsibility policy in May 2004. The organization has built practices in this area to manage emerging risks associated with suppliers, employees, stakeholders and First Nations.

First Nations past grievances, land claims, service reliability and regulatory processes pose risks to BC Hydro. These risks are managed through a comprehensive Aboriginal Relations program. The long-term goal of further building business relationships with First Nations is intended to go beyond addressing the impact of BC Hydro facilities on First Nations and reducing the associated financial, legal and operating risks, to having a more proactive, mutually beneficial approach to working together.

### FUTURE OUTLOOK

The *Budget Transparency and Accountability Act* requires that BC Hydro file a Service Plan each February. BC Hydro's Service Plan filed in February 2009 forecasts income before regulatory accounts for fiscal 2010 at \$314 million and net income at \$452 million. BC Hydro received a decision from the BCUC on its F2009/2010 Revenue Requirements Application on March 13, 2009. The impact of the decision on BC Hydro's fiscal 2010 forecast was to update its forecast income from the Service Plan to forecast income before regulatory accounts of \$287 million and forecast net income of \$457 million. A summary of the changes relating to the BCUC decision is described in the Regulation section.

BC Hydro's earnings can fluctuate significantly due to various non-controllable factors such as the level of water inflows, customer load, market prices for electricity and natural gas, weather, temperatures, interest rates and foreign exchange rates. The Service Plan and updated forecast for fiscal 2010 assume average water inflows, customer load of 52,855 GWh, average market electricity prices of CDN \$54.70/MWh, short-term interest rates of 2.30 per cent and a US dollar exchange rate of US \$0.9103.

## FINANCIAL RESULTS

### EARNINGS SENSITIVITY

The following table shows the effect on earnings of changes in some key variables. The analysis is based on business conditions and production volumes forecast for fiscal 2010. Each separate item in the sensitivity analysis assumes the others are held constant. While these sensitivities are applicable to the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitude of changes. All of these variances are subject to regulatory accounting treatment in fiscal 2010.

Factor	Change	Approximate change in earnings before regulatory deferral account transfers		
		(in millions)	5 year high	5 year low
Hydro generation <sup>1</sup>	1,000 GWh	\$ 55	52,140 GWh	41,601 GWh
Electricity trade margins	\$1/MWh	40	n/a	n/a
Interest rates	+/- 1%	30	4.50% <sup>2</sup>	2.39% <sup>2</sup>
Exchange rates (US/ CDN)	\$0.01	5	\$0.97 <sup>3</sup>	\$0.78 <sup>3</sup>
Weather	1°C change in average temperature	5	0.4°C <sup>4</sup>	-1.5 °C <sup>4</sup>
Pension costs	1% change in the expected return of 7.5% on pension assets <sup>5</sup>	5	15.0%	-23.0%

<sup>1</sup> Assumes change in hydro generation is offset by corresponding change in energy imports (i.e. increase in hydro generation is offset by decrease in energy imports).

<sup>2</sup> Interest rates are the average Canadian short-term interest rates (3 month Canadian Dollar Offered Rate).

<sup>3</sup> Exchange rates are the average US Dollar noon rates for fiscal 2005 to fiscal 2009.

<sup>4</sup> Weather high and low numbers represents the variance in degrees Celsius from the normal temperatures over the winter months November to March from 2004/05 to 2008/09. [-1.5 degrees lower than normal to 0.4 degrees higher than normal – normal is the 10-year rolling average].

<sup>5</sup> The impact of this change affects earnings in the subsequent year.