BC HYDRO & POWER AUTHORITY MANAGEMENT DISCUSSION AND ANALYSIS

The Management Discussion and Analysis reports on British Columbia Hydro and Power Authority's (BC Hydro or the Company) consolidated results and financial position for the year ended March 31, 2011 (fiscal 2011). 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, 2011 and 2010. 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 2011 benefited from higher domestic gross margins primarily due to higher average customer rates and lower domestic energy costs, and from lower finance charges, partially offset by higher non-energy operating costs and lower energy trading margins than in the prior year.

HIGHLIGHTS

- Net income after regulatory account transfers for the year ended March 31, 2011 was $589 million, compared to $447 million in the prior year and was $18 million above the revised forecast for fiscal 2011 of $571 million included in BC Hydro's February 2011 Service Plan. The Service Plan for fiscal 2011 originally filed in February 2010 had a target net income of $609 million, but the mid-year integration of the British Columbia Transmission Corporation (BCTC) and the financial impacts of the Negotiated Settlement Agreement (NSA) on BC Hydro's F2011 Revenue Requirements Application (RRA) resulted in the reduced net income forecast reported in the February 2011 Service Plan.
- The NSA on BC Hydro's F2011 RRA, approved by the British Columbia Utilities Commission (BCUC) in December 2010, resulted in rate adjustments for domestic customers for the period January 1, 2011 to March 31, 2011. The overall annual bill impact for fiscal 2011 was a rate increase of 7.29 per cent.
- Hydro generation levels for the year ended March 31, 2011 were 6 per cent lower than in the prior year, primarily due to lower water inflows. System water inflows during the year were at 86 per cent of average. This follows a similar low water year in fiscal 2010 which was 87 per cent of average.
- Capital expenditures of $1.5 billion for the year were $887 million lower than in the prior year largely due to the acquisition in the prior year of a one-third interest in the Waneta dam and generating facility. Exclusive of this one-time significant acquisition, BC Hydro's expenditures on the expansion of its facilities to meet future load growth requirements and on maintaining its aging infrastructure were comparable to the prior year.

For the year ended March 31 *(in millions)*	2011	2010	Change
Total Assets	$ 19,479	$ 17,989	$ 1,490
Shareholders' Equity	$ 2,880	$ 2,674	$ 206
Net Income	$ 589	$ 447	$ 142
Accrued Payment to the Province	$ 463	$ 47	$ 416
Property, Plant and Equipment Expenditures	$ 1,519	$ 2,406	$ (887)
Return on Equity	14.13%	12.49%	1.64%
Debt to Equity Ratio	80 : 20	80 : 20	—
Number of Domestic Customers	1,853,137	1,830,698	22,439
GWh Sold (Domestic)	50,607	50,233	374
Total Reservoir Storage (GWh)	12,610	12,328	282

CONSOLIDATED RESULTS OF OPERATIONS

As a rate-regulated utility, BC Hydro applies various accounting policies that are acceptable under Canadian 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.

Commencing in fiscal 2011, BC Hydro changed its reporting of regulatory account transfers on the statement of operations to report individual line items net of transfers to regulatory accounts, as compared to prior years in which aggregate net transfers to regulatory accounts were reported as a single separate line item and income was reported both before and after regulatory account transfers. An exception is trade revenue, for which the regulatory account transfer is netted with the trade cost of energy regulatory account transfer to reflect a net trade margin transfer. Amounts in the prior year's comparative statement of operations have been reclassified to conform to the current year's presentation of changes in regulatory accounts and the current year's classification of operating expenses. Detail on regulatory account transfers can be found in the MD&A and in Note 4 to the audited consolidated financial statements.

The transfers to regulatory accounts reflected in net income on the consolidated statement of operations include: variances between forecast and actual amounts for certain costs, including cost of energy, trade income and finance charges; certain amounts incurred in the current period that are deferred for future recovery in rates (such as demand-side management expenditures and liability provisions); interest accrued on regulatory accounts where allowed; and amortization of regulatory accounts into income.

For the year ended March 31, 2011, net transfers to regulatory accounts of $447 million were mainly to the Non-Heritage Deferral Account (NHDA) due to higher than planned energy costs resulting from low water inflows which were not reflected in the fiscal 2011 rate increase and lower than planned domestic revenues, partially offset by lower purchases from Independent Power Producers (IPPs) and purchases for future trade; additions to the Trade Income Deferral Account (TIDA) for the variance between planned and actual trade income as a result of lower than planned price spreads due to poor market conditions and the need to import electricity due to the low water inflows into the BC Hydro system; expenditures on Demand-Side Management (DSM); and a reduction of the Environmental Compliance regulatory account for a revision to BC Hydro's estimated future environmental compliance and remediation expenditures related to polychlorinated biphenyls (PCBs).

Net income for the year ended March 31, 2011 was $589 million, an increase of $142 million from the prior year mainly as a result of higher domestic revenues due to higher average customer rates and an increase in the rate rider, lower operating costs primarily due to lower expenditures for electricity and gas purchases, and lower finance charges, partially offset by lower trade income. All variances are after the effect of applicable transfers to regulatory accounts.

REVENUES

For the year ended March 31	*(in millions)* **2011**	*(Revised)* 2010	*(gigawatt hours)* **2011**	*(Revised)* 2010
Domestic				
Residential	**$ 1,398**	$ 1,300	**17,797**	17,593
Light industrial and commercial	**1,237**	1,133	**18,052**	17,811
Large industrial	**539**	485	**13,164**	13,020
Other energy sales	**229**	220	**1,594**	1,809
Total Domestic Revenue Before Regulatory Transfer	**3,403**	3,138	**50,607**	50,233
Domestic load variance regulatory transfer	**35**	151	**—**	—
Total Domestic	**$ 3,438**	$ 3,289	**50,607**	50,233
Trade				
Electricity – Gross	**$ 1,028**	$ 1,320	**26,253**	28,210
Less: forward electricity purchases[1]	**(565)**	(749)	**—**	—
Electricity – Net	**463**	571	**—**	—
Gas – Gross	**942**	789	**23,362**	20,632
Less: forward gas purchases[1]	**(827)**	(621)	**—**	—
Gas – Net	**115**	168	**—**	—
Total Trade	**$ 578**	$ 739	**49,615**	48,842
Total	**$ 4,016**	$ 4,028	**100,222**	99,075

[1] *Forward purchases include derivatives which are deducted from gross sales in accordance with GAAP.*

Total revenue for the year ended March 31, 2011 was $4,016 million, comparable to revenues of $4,028 million in the prior year. Domestic revenues were higher due to higher average rates in all customer classes, while trade revenues were lower due to weak demand for market energy primarily due to uncertainty over the strength of the economic recovery in the U.S. and lower electricity prices. The decrease in trade revenue reflects lower commodity prices and weaker demand for trade electricity due to the ongoing economic uncertainty in the U.S., partially offset by higher gross gas sales prices and volumes before deducting forward purchases, which were higher than in the prior year.

DOMESTIC REVENUES

Total domestic revenues of $3,438 million for fiscal 2011 were $149 million or 5 per cent higher than in the previous year. The increase for the year was due to higher average customer rates in all rate classes. The effective annual rate increase for fiscal 2011 was 4.67 per cent, made up of a 6.11 per cent increase for the period April 1, 2010 to December 31, 2010 and a rate credit of 4.71 per cent applied for the period January 1, 2011 to March 31, 2011. The rate rider increased from 1 per cent to 4 per cent for the period April 1, 2010 to December 31, 2010 and decreased to 2.5 per cent for the period January 1, 2011 to March 31, 2011 for an effective annualized rate rider increase of 3.53 per cent. Together the rate and rate rider increases resulted in a total average annual customer bill impact of an increase of 7.29 per cent in fiscal 2011. Domestic sales volumes were comparable to the prior year. Any variances between actual and planned load are deferred to the NHDA.

TRADE REVENUES

Powerex, a wholly owned subsidiary of BC Hydro, is a key participant in energy markets across North America, buying and supplying wholesale power, natural gas, ancillary services, and financial energy products and, more recently, environmental products with an expanding list of trade partners.

BC Hydro's electricity system is interconnected with systems in Alberta and the Western United States, facilitating sales and purchases of electricity outside of British Columbia. Powerex's 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.

Gross trade revenue for the year ended March 31, 2011 decreased by $139 million from fiscal 2010 due to a decrease in gross electricity revenue of $292 million, partially offset by an increase in gross gas revenue of $153 million. The decrease in gross electricity revenue was primarily driven by a 16 per cent decrease in the average electricity sales price over the prior year, partly due to the strengthening of the Canadian dollar against the U.S. dollar over the fiscal year, and a 7 per cent decrease in electricity sales volumes. The decrease in electricity prices and volumes was primarily a result of low demand in California due to the economic downturn and a cool summer along the U.S. west coast, partially offset by higher sales prices and volumes into Alberta. The increase in gross gas revenue was due to a 13 per cent increase in gas sales volumes and a 5 per cent increase in the average gas sales price. Deducted from gross trade revenue are forward purchases, which increased by a net $22 million compared to the prior year. Forward transactions are reported on a net basis in accordance with GAAP.

OPERATING COSTS

In fiscal 2011, BC Hydro changed its classification of operating expenses to a presentation of costs based on the nature of the expenditures. Amounts previously reported as operations, maintenance and administration are now classified by the nature of the expense as outlined in Note 6 in the audited consolidated financial statements.

For the year ended March 31, 2011, total operating costs of $2,992 million were $89 million lower than in the prior year. The decrease is due to a reduction in the cost of energy, partially offset by increases in non-energy operating expenses including increases in personnel expenditures, higher amortization expense, higher grants and taxes and other operating costs, partially offset by lower materials and services expenditures.

COST OF ENERGY

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:

For the year ended March 31	(in millions) 2011	(Revised) 2010	(gigawatt hours) 2011	(Revised) 2010	($ per MWh) 2011[2]	(Revised) 2010[2]
Domestic						
Water rental payments (hydro generation)	$ **298**	$ 294	**39,675**	42,115	$ **7.59**	$ 6.80
Purchases from independent power producers	**676**	568	**10,805**	8,893	**62.53**	61.49
Other electricity purchases – domestic	**128**	80	**3,791**	2,161	**33.72**	37.33
Gas for thermal generation	**44**	50	**251**	400	**175.53**	110.30
Transmission charges and other expenses	**26**	64	**114**	113	**—**	—
Allocation to/from trade energy	**38**	68	**1,077**	1,525	**36.95**	33.94
Total Domestic Cost of Energy Before Regulatory Transfers	**1,210**	1,124	**55,713**	55,207	**21.72**	20.36
Domestic cost of energy regulatory transfers	**(161)**	21	**—**	—	**—**	—
Total Domestic	$ **1,049**	$ 1,145	**55,713**	55,207	$ **18.83**	$ 20.74
Trade						
Electricity – Gross	$ **792**	$ 1,114	**26,925**	29,453	$ **29.42**	$ 37.82
Less: forward electricity purchases[1]	**(565)**	(749)	**—**	—	**—**	—
Electricity – Net	**227**	365	**—**	—	**—**	—
Remarketed gas – Gross	**881**	746	**23,876**	21,276	**36.90**	35.06
Less: forward gas purchases[1]	**(827)**	(622)	**—**	—	**—**	—
Other gas purchases – Net	**54**	124	**—**	—	**—**	—
Transmission charges and other expenses	**191**	221	**—**	—	**—**	—
Allocation to/from domestic energy	**(38)**	(68)	**(1,077)**	(1,525)	**36.95**	33.94
Total Trade Cost of Energy Before Regulatory Transfers	**434**	642	**49,724**	49,204	**20.20**	28.42
Trade net margin regulatory transfers	**(68)**	(166)	**—**	—	**—**	—
Total Trade	$ **366**	$ 476	**49,724**	49,204	$ **18.84**	$ 25.04
Total Energy Costs	$ **1,415**	$ 1,621	**105,437**	104,411	$ **18.83**	$ 22.77

[1] Other electricity purchases in dollars include purchases for trade activities shown net of derivatives. Gigawatt hours (GWh) and $ per Megawatt hour (MWh) are shown at gross cost.

[2] Total cost per MWh includes other electricity purchases at gross cost.

For the year ended March 31, 2011, total energy costs, after regulatory account transfers, were $1,415 million, 13 per cent lower than the previous year as a result of lower domestic and trade energy costs after transfers to regulatory accounts. Before regulatory transfers, domestic energy costs were higher due to higher purchases required to offset low generation levels which resulted from low water inflows, and trade energy costs were lower due to lower trade electricity purchase prices and volumes, partially offset by higher volumes for gas purchases for trade.

DOMESTIC ENERGY COSTS

Domestic energy costs before regulatory transfers of $1,210 million for the year ended March 31, 2011 were 8 per cent higher than in the prior year. The increase was mainly due to higher purchases from IPPs and higher market energy purchases, partially offset by lower transmission costs and purchases for future trade. The increase in IPP purchases was primarily due to two new bio-energy projects which started in late fiscal 2010, agreements in the current year to purchase additional energy from two existing IPPs, and increased purchases from Alcan that BC Hydro was required to make due to Alcan's reduced smelter load. Market electricity purchase volumes were higher as the reduced generation levels resulting from lower water inflows during the year required BC Hydro to purchase energy from the market to meet domestic load requirements. Water rental costs for the year were comparable to the prior year as an 8.74 per cent increase on water rental fees and additional water rental fees associated with the one-third interest in the Waneta dam and generating facility acquired in March 2010 were offset by the impact of lower generation levels due to lower water inflows. Variances between actual and planned domestic cost of energy are transferred to the Heritage Deferral Account (HDA) and NHDA.

TRADE ENERGY COSTS

Gross trade energy costs for the year ended March 31, 2011 decreased by $187 million from fiscal 2010 primarily due to a $322 million decrease in gross electricity purchases for trade, partially offset by a $135 million increase in gross gas purchases. Gross electricity purchases reflect a 22 per cent decrease in the average electricity purchase price, partly due to the strengthening of the Canadian dollar against the U.S. dollar over the fiscal year, and a 9 per cent decrease in electricity purchase volumes. As with electricity sales, this is primarily due to the economic downturn and a cool summer, which reduced demand in California, partially offset by higher sales prices and volumes into Alberta. Remarketed gas purchase costs increased due to a 5 per cent increase in the average gas purchase price and a 12 per cent increase in gas purchase volumes reflecting seasonal price spreads that resulted in increased cycling of gas storage. Deducted from gross trade energy costs are forward purchases, which increased by a net $21 million compared to the prior year. Forward purchases are netted against forward sales within gross revenue in accordance with GAAP.

WATER INFLOWS

System inflows were approximately 86 per cent of average in fiscal 2011, comparable to inflows of 87 per cent of average in fiscal 2010. System inflows for fiscal 2012 are forecast to be 101 per cent of average, with inflows to the Williston Reservoir on the Peace River system at 100 per cent and the Kinbasket Reservoir on the Columbia River system at 103 per cent.

Water Supply for the past two Water Years has been some of the lowest on record. The 2010 Water Year (Feb-Sept 2010) was 81 per cent of normal and the lowest in 51 years of record. The 2009 Water Year (Feb-Sept 2009) was 86 per cent of normal and the fifth lowest on record. The low system inflows did not present any serious operational issues. System Inflows for the 2011 Water Year (Feb-Sept 2011) are forecast to be 101 per cent of normal (based on April Water Supply Forecast).

BC Hydro reservoirs have been managed such that the combined storage in BC Hydro reservoirs at the end of fiscal 2011 was 99 per cent of average, with the Williston and Kinbasket reservoirs at 89 per cent and 110 per cent of average, respectively. In comparison, combined system storage at the end of fiscal 2010 was 94 per cent of average.

PERSONNEL EXPENSES

Personnel expenses include labour, benefits and employee future benefits. Personnel costs, after net regulatory transfers, of $541 million for the year ended March 31, 2011 were $69 million higher than in the previous year primarily due to higher non-current pension costs.

MATERIALS AND EXTERNAL SERVICES

Materials and external services include expenditures for operating and maintenance materials and services provided by third parties. Expenditures on materials and external services, after net regulatory transfers, of $585 million for the year ended March 31, 2011 were $20 million lower as compared to the prior year. The reduction is mainly due to changes in levels of maintenance and other operational activities, including expenditures in fiscal 2010 on initiatives not continued in the current year and lower current year expenditures on various distribution maintenance and work programs and generation operations civil and maintenance initiatives, partially offset by costs recognized in the current year for the operating portion of Energy Purchase Agreements (EPAs) treated as capital leases in fiscal 2011 but treated as cost of energy in the prior year.

CAPITALIZED COSTS

Capitalized costs are overhead costs incurred to support capital expenditures and are transferred from operating costs to property, plant and equipment. Capitalized costs for the year ended March 31, 2011 are $270 million, $10 million lower than in the prior year, in line with a reduction in capital expenditures on property, plant and equipment in the current year.

AMORTIZATION AND DEPRECIATION

Amortization and depreciation expense includes the depreciation of property, plant and equipment, intangible assets, asset retirement obligation (ARO) assets, amortization of customer contributions and the amortization of certain regulatory assets and liabilities. For the year ended March 31, 2011, amortization and depreciation expense was $533 million compared with $487 million in the prior year. The increase was primarily due to higher assets in service as a result of BC Hydro's capital expenditure program, partially offset by lower net regulatory account amortization.

GRANTS AND TAXES

As a Crown Corporation, BC Hydro is exempt from paying federal and provincial income taxes, but pays local government taxes and grants in lieu to municipalities and regional districts. Total grants, school taxes and other local taxes of $184 million for the year ended March 31, 2011 were comparable to the $178 million paid in the prior year.

FINANCE CHARGES

Finance charges for the year ended March 31, 2011 of $435 million were $65 million lower than in the prior year. The reduction is primarily due to a decrease of $106 million in other finance charges, partially offset by an increase in interest on long term debt. Actual other finance charges in fiscal 2010 were significantly lower than the forecast finance charges primarily due to the difference between the forecasted weighted average cost of debt as compared to the actual weighted average cost of debt incurred in the year. This difference resulted in a $105 million increase in fiscal 2010 other finance charges after regulatory transfer. The regulatory transfer in fiscal 2011 was immaterial. The increase in interest on long-term debt is primarily due to an increase in the planned volume of long-term debt issues in fiscal 2011 as compared to the prior year.

REGULATORY TRANSFERS

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 have the effect of adjusting net income. The deferred amounts are then included in customer rates in future periods, subject to approval by the BCUC.

The net change in regulatory accounts on the consolidated statement of operations includes: 1) the deferral of differences between planned and actual results for cost of energy (including variances related to load), trade income, finance charges and non-current pension costs; 2) costs deferred for future recovery in rates, such as costs for DSM and Site C; and 3) interest accrued on regulatory accounts, where allowed, and amortization of regulatory accounts.

Regulatory transfers are comprised of the following:

For the year ended March 31 *(in millions)*	2011	*(Revised)* 2010
Variances between forecast and actual costs		
Energy deferral accounts	$ 296	$ 249
Finance charges	(4)	(105)
Non-current pension deferral	3	86
Other	(18)	(76)
	277	154
Deferral of costs for future recovery in rates		
Demand-Side Management programs	128	130
Return on Equity	—	56
Environmental Compliance	(83)	321
Other	120	82
	165	589
Amortization of regulatory accounts	(32)	(90)
Interest on regulatory accounts	37	42
Net change in regulatory accounts	$ 447	$ 695

For the year ended March 31, 2011, BC Hydro transferred, on a net basis, $447 million to regulatory accounts, compared with the transfer of $695 million to the regulatory accounts during the prior year. The majority of the transfers relate to the cost of energy deferral accounts. The net asset balance in the regulatory asset and liability accounts as at March 31, 2011 was an asset of $2,160 million compared to $1,713 million at March 31, 2010.

The significant transfers to the energy deferral accounts reflect higher than planned domestic cost of energy as a result of higher energy purchase costs as increased market energy purchases were required due to low water inflows, lower domestic revenues due to lower consumption, and lower than planned trade income due to low price spreads caused by lower commodity prices for electricity and natural gas. Finance charges are on plan in the current year as compared to fiscal 2010 where they were significantly lower than plan due to lower than planned short term interest rates. Non-current pension costs are on plan in the current fiscal year as compared to fiscal 2010 where they were significantly higher than planned due to the net actuarial loss experienced by the BC Hydro pension plan in fiscal 2009. DSM expenditures and transfers are comparable to the prior year. The Environmental Compliance account transfers reflect a reduction in the provision in the current year for estimated future environmental compliance and remediation expenditures related to PCBs due to a reduction in the estimate of these expenditures.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

The *Budget Transparency and Accountability Act* (BTAA) specifies that the Government and government organizations conform to the set of standards and guidelines that comprise generally accepted accounting principles for senior governments in Canada, unless otherwise directed by Treasury Board. Accounting standards for senior government are understood to mean standards established by the Public Sector Accounting Board (PSAB), which directs Government Business Enterprises (GBE) to adhere to International Financial Reporting Standards (IFRS). BC Hydro is classified as a GBE. Qualifying entities with rate-regulated activities have the option of deferring the adoption of IFRS and continuing to apply the accounting standards in Part V of the CICA Handbook—*Accounting* until their annual periods beginning on or after January 1, 2012. BC Hydro will use the deferral option. For subsequent years, alternatives available pursuant to Section 23.1 of the BTAA may be considered by Treasury Board. The Company is continuing to evaluate the impact on its consolidated financial statements of the adoption of IFRS and will work with Treasury Board with respect to potential alternatives.

PAYMENT TO THE PROVINCE

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. The dividend accrued for the year ended March 31, 2011 is $463 million, which is 84 per cent of distributable surplus, below 85 per cent due to the 80:20 cap.

LEGAL PROCEEDINGS

Since 2000, Powerex has been named, along with other energy providers, in lawsuits and U.S. federal regulatory proceedings which seek refunds, 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. At March 31, 2011, Powerex was owed US $265 million (CDN $258 million) by the California Power Exchange and the California Independent System Operator related to Powerex's trade activities in California during the period covered by the lawsuits. It is expected those receivables will be offset against any refunds that Powerex is required to pay. Additional detail on the proceedings can be found in Note 16 to the audited consolidated financial statements.

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.

REGULATION

In the process of 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 a certain return on equity (ROE). The annual rate of ROE 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*. This is in accordance with Heritage Special Direction No. HC2. Order in Council No. 074 dated February 17, 2009 amended Heritage Special Direction No. HC2 to allow for an adder of 1.63 per cent in fiscal years 2010, 2011 and 2012. The allowed rate of ROE for fiscal 2011 is 14.37 per cent, and is higher than the prior year's allowed rate of 13.05 per cent due to the higher rate of return allowed for FortisBC Energy Inc. (formerly Terasen Gas Inc.), upon which BC Hydro's return on equity is based.

Order in Council No. 020 dated February 2, 2011 and effective April 1, 2011 amended Heritage Special Direction No. 2, so that BC Hydro's return on equity will be based on total assets in service rather than total debt and equity.

F2011 REVENUE REQUIREMENT APPLICATION (RRA)

BC Hydro's F2011 RRA was filed with the BCUC on March 3, 2010 requesting a 6.11 per cent rate increase and an increase in the Deferral Account Rate Rider (DARR) from 1 per cent to 4 per cent. The increases were approved by the BCUC on an interim basis effective April 1, 2010.

BC Hydro and interveners entered into a negotiated settlement process in September 2010 to resolve the application. A NSA was reached and was approved by the BCUC on December 2, 2010.

The NSA confirmed the 6.11 per cent rate increase as final with a 4.71 per cent rate credit applied to customers' bills for the period January 1 to March 31, 2011 to reflect the NSA adjustments. The DARR was finalized at 4 per cent for the April 1 through December 31, 2010 period and 2.5 per cent thereafter. In combination, the overall fiscal 2011 annual bill impact of these adjustments to customers is 7.29 per cent.

The main financial impacts of the NSA in fiscal 2011 include write-offs of $5.5 million to the Procurement Enhancement Initiative (PEI) Regulatory Account balance and $10.3 million to the DSM Regulatory Account balance and a reduction of $35 million in the operating cost forecast for fiscal 2011. These changes impact fiscal 2011 financial results. The NSA also included several commitments by BC Hydro to address specific issues in its next revenue requirements application.

F2012–2014 RRA

BC Hydro's F2012–F2014 RRA was filed with the BCUC on March 1, 2011, requesting an average rate increase of 9.73 per cent per year in each of fiscal 2012 to fiscal 2014. These requested rate increases reflect increasing capital-related costs (amortization, financing costs and return on equity) due to higher levels of investment in assets; an increase in domestic energy costs due to purchases of higher-priced new supply; and a reduction in forecast trade income due to forecast weaker export market conditions.

On April 21, 2011 the BCUC approved an average interim rate increase of 8 per cent effective May 1, 2011 and suspended the regulatory process for reviewing the F2012–F2014 RRA until the completion of a provincial government review of BC Hydro. The outcome of this review will be incorporated into an amended revenue requirements application to the BCUC, expected to be filed in late summer/early fall 2011.

INTERIOR TO LOWER MAINLAND TRANSMISSION (ILM) PROJECT

The BCUC reconsidered the ILM application for the purpose of determining the adequacy of First Nations consultation on this project from 2006 up to the point when the Certificate of Public Convenience and Necessity (CPCN) was issued in August 2008. Construction on this project has been suspended, pending a decision on this matter.

The BCUC issued its decision on February 3, 2011, finding that the Crown's duty to consult with certain First Nations had not been adequately met as of August 5, 2008, and as result, continuing the suspension of the ILM CPCN. BC Hydro has been directed to conduct further consultation and file a compliance report in June addressing these deficiencies for the BCUC's review before the CPCN suspension can be lifted.

On March 2, 2011, an application to the BCUC seeking reconsideration of this decision was filed by several First Nations. After a written comment process, the BCUC determined that the application did not meet the threshold for a reconsideration to proceed and thus dismissed the application on May 6, 2011.

RUSKIN DAM UPGRADE PROJECT

On February 22, 2011, BC Hydro filed an application for a CPCN for the Ruskin Dam Upgrade Project. This project involves replacing parts of the seismically deficient dam, and rehabilitating or replacing the powerhouse, including generating equipment and associated transmission facilities. On February 24, 2011, the BCUC established a written public hearing and regulatory timetable for the review of the application. A decision is expected in late 2011.

LARGE GENERAL SERVICE (LGS) RATE APPLICATION

On October 16, 2009, BC Hydro filed its LGS Rate application with the BCUC. BC Hydro proposed to split the existing rate class into large (LGS) and medium (Medium General Service, "MGS") commercial classes. New rate structures were proposed for each new customer class to encourage conservation and energy efficiency. A NSA regarding the restructuring of the commercial class rate was reached by BC Hydro and its customers and was approved by the BCUC on June 29, 2010. New rates for the LGS became effective January 1, 2011 while MGS rates will be phased in over a six year period ending April 1, 2015.

OTHER APPLICATIONS REVIEWED BY THE BCUC IN FISCAL 2011

Several other applications received approval from the BCUC in F2011. These include:

- Stave Falls Spillway Gates Project;
- Hugh Keenleyside Spillway Gates Project;
- Vancouver City Central Transmission Project (Mount Pleasant/False Creek area);
- Columbia Valley Transmission Project; and
- Remote Community Electrification Projects (St'at'imc, Tsay Keh, Fort Ware and Elhateese communities).

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the year ended March 31, 2011 was $668 million, compared to $373 million for the prior year. The increase was primarily due to an increase in net income and changes in working capital relative to the prior year.

The long-term debt balance net of sinking funds at March 31, 2011 was $11.5 billion, compared with $10.7 billion at March 31, 2010. The increase was mainly a result of net long-term bond issues totaling $593 million ($600 million par value) less long-term bond retirements totaling $150 million ($150 million par value) and an increase in revolving borrowings of $409 million. The increases in short-term and long-term debt include debt transferred to BC Hydro on the integration of BCTC which does not affect cash flow. These increases were partially offset by net foreign exchange revaluation gains on bonds and sinking funds of $48 million, a decrease of $19 million in debt due to fair value hedge accounting, amortization of premiums of $8 million and sinking fund income of $5 million. The increase in revolving borrowings was due to the funding of capital expenditures and the Payment to the Province related to fiscal 2010 earnings.

All derivative financial instruments are required to be carried on the balance sheet at fair value. As at March 31, 2011, BC Hydro recorded a net derivative financial instrument liability of $147 million ($224 million asset less $371 million liability) compared with a net derivative financial instrument liability of $97 million ($520 million asset less $617 million liability) in the prior year. The change resulted from losses on foreign currency contracts due to the increased strength of the Canadian dollar relative to the U.S. dollar and from the decline in value of interest rate swaps while others were impacted by rising interest rates, and from a decrease in the value of commodity derivatives as a result of the expiry of large asset and liability positions in gas and electricity arising from large historic price movements.

PROPERTY, PLANT AND EQUIPMENT EXPENDITURES

Property, plant and equipment expenditures were as follows:

(in millions)	**2011**	2010	Change
Distribution improvements and expansion	**$ 429**	$ 425	$ 4
Generation replacements and expansion	**420**	461	(41)
Waneta Dam and generating facility – one-third interest	**—**	841	(841)
Transmission lines and substation replacements & expansion	**437**	389	48
General, including computers and vehicles	**233**	290	(57)
Total Property, Plant and Equipment Expenditures	**$ 1,519**	$ 2,406	$ (887)

Total property, plant and equipment expenditures presented in this table are different from the amount of property, plant and equipment and intangible asset expenditures in the consolidated Statement of Cash Flows in the consolidated financial statements due to effect of accruals related to these expenditures.

Generation replacement and expansion expenditures for the year ended March 31, 2011 decreased by $41 million over the prior year. The decrease is mainly due to lower spending in the current year on the Revelstoke Unit 5 Installation, which was placed in service in December 2010, partially offset by increased spending on the Mica SF_6 GIS Replacement and the Fort Nelson Resource Smart Upgrade.

Transmission lines and substations capital expenditures for the year ended March 31, 2011 increased by $48 million compared with the prior year. The increase is mainly due to expenditures on the Saanich Peninsula Project, the Central Vancouver Island Project and the right of way purchase of the CN Rail Electrical Works Corridor.

General capital expenditures decreased by $57 million for the year ended March 31, 2011 compared with the prior year. The decrease is mainly due to lower expenditures on vehicle purchases, as many units were replaced in the last half of the year in fiscal 2010, and lower expenditures on the Port Mann Bridge highway relocation. Lower expenditures on the Home Purchase Offer Program (HPOP) in Tsawwassen have also contributed to the decrease; this is partially offset by higher expenditures on the Smart Metering & Infrastructure Program, construction of a new field building in the Lower Mainland and purchase of the Edmonds Annex Building.

CAPITAL LEASES

In accordance with Canadian GAAP, EPAs with Island Co-Generation (ICG) and Dokie Wind Energy are accounted for as capital leases. This has resulted in the recognition of capital lease assets and corresponding liabilities of $480 million which will be amortized over the term of the EPAs. Purchases of energy under these EPAs are recorded in the income statement as to the nature of the costs, being operating costs, taxes, amortization, finance charges and cost of energy, as opposed to the EPAs that are not treated as capital leases under which purchases are accounted for as cost of energy.

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 for fiscal 2011 was filed in February 2010 and forecast net income at $609 million. In fiscal 2011, the integration of BCTC, the F2011 RRA NSA, and changes to the presentation of certain financial statement items to a net, nature view, have resulted in revisions to the fiscal 2011 targets as reported in the February 2010 Service Plan. The impact of these changes are reflected in the Service Plan Reforecast submitted together with the fiscal 2012 Service Plan in February 2011 and these are the targets against which meaningful comparison of fiscal 2011 results can be made.

Domestic gross margin was higher than forecast due to higher miscellaneous domestic revenues, as all other variances are deferred to the energy deferral accounts.

Net trade margins were comparable to the Service Plan reforecast. Lower than forecast energy trading revenues were offset by lower than forecast cost of energy for trade.

Other operating costs and finance charges were comparable to the Service Plan reforecast.

The table below provides an overview of BC Hydro's financial performance relative to its 2010 results and to its 2011 Service Plan forecast. The results and forecasts form the basis upon which key performance targets are set. The 2011 variance column compares actual fiscal 2011 results to the February 2011 Service Plan Reforecast.

(in millions)		Actual		Service Plan Forecast February 2010	Service Plan Reforecast February 2011	2011 Variance
	2009	2010	2011	2011	2011	
Revenues						
Total Domestic	$ 2,814	$ 3,289	$ 3,438	$ 3,404	$ 3,414	$ 24
Trade	1,455	739	578	1,385	1,259	(681)
	4,269	4,028	4,016	4,789	4,673	(657)
Expenses						
Operating costs						
Cost of energy	2,393	1,621	1,415	2,332	2,092	677
Other operating expenses	1,477	1,460	1,577	1,717	1,577	—
	3,870	3,081	2,992	4,049	3,669	677
Operating Income	399	947	1,024	740	1,004	20
Finance Charges	472	500	435	483	433	(2)
Income (Loss) Before Regulatory Account Transfers	(73)	447	589	257	571	18
Net Change in Regulatory Accounts	438	—	—	352	—	—
Net Income	$ 365	$ 447	$ 589	$ 609	$ 571	$ 18

RISK MANAGEMENT

BC Hydro faces risks to its business that could significantly impact its ability to achieve its short- and long-term financial, social and environmental goals. The goal of risk management is not to eliminate risks, but rather to mitigate them to levels which are commensurate with the potential benefits to be derived. Similarly, BC Hydro's risk management strategies aim to mitigate risks through a consistent risk management process that is applied to day-to-day business activities as well as to specific projects and initiatives. BC Hydro's Chief Risk Officer is responsible for facilitating this risk management process and promoting strong oversight of significant risks by the BC Hydro Risk Management Committee. BC Hydro's Board of Directors also plays a key role in the oversight of risk management, as the Board must understand the risks being taken by BC Hydro and ensure that processes are in place to appropriately manage the risks. 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 generation, transmission and distribution of electricity inherently results in certain safety risks to both BC Hydro workers and the public. To manage worker and public safety, BC Hydro relies on education and training, safe design, safety practice regulations and communication. BC Hydro also prepares emergency response plans to limit injury and loss to life and to restore electric service. The large dams represent a catastrophic loss risk (low probability but high consequence) 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.

Significant risks to the reliability of BC Hydro's system include aging infrastructure and the impact of weather. 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 and replacement programs, emergency response programs, a diverse supply of energy options, and through cooperative support arrangements with neighbouring utilities.

System inflows, market prices, and domestic load influence cost of energy. The system inflow energy for fiscal 2012 is now expected to be slightly above normal and the system is forecast to be in a small net sales position for fiscal 2012. Several factors constrain BC Hydro's ability to use its stored system energy to meet load throughout the year. These factors include generating unit outages at major plants (forced outages and capital projects) as well as water management constraints which limit generation at the major plants during some periods. Even when the system has annual net energy sales, some electricity purchases are likely required during constrained periods of the year (e.g. late fall, winter, early spring), while electricity sales may be unavoidable during other periods to minimize spill from system reservoirs. The value of these purchases and sales is subject to market price risk. Electricity demand is generally increasing as B.C.'s population increases. However this demand can be volatile, particularly due to large industrial customers who may curtail or expand their operations due to the state of export markets and world commodity prices. BC Hydro's risk mitigation strategy is to achieve energy security and price certainty by developing adequate domestic electricity supplies, and through energy conservation and efficiency. BC Hydro regularly models the projected supply-demand balance of the system over the short term to plan optimum system operations and over the medium term in an effort to cost-effectively meet demand.

Legal and regulatory requirements for First Nation consultation, claims of historic grievances, land claims, and service reliability issues pose risks to BC Hydro. These risks are managed through a comprehensive aboriginal relations program. Building mutually-beneficial relationships with First Nations reduces financial, legal, regulatory and operating risks.

In meeting its financial performance targets, BC Hydro faces many risks including uncertain economic conditions, variable costs and revenues as driven by 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. Tariff rates are set based upon BC Hydro's cost forecast and allowed return on deemed equity. Many financial risks (differences between forecast and actual costs) associated with uncontrollable costs are mitigated through regulatory deferral accounts. Increasing costs due to aging infrastructure, the modernization and refurbishment of the electricity system, the need for new supply and the need to manage environmental impacts create challenges for BC Hydro in maintaining rates that meet customer expectations.

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.

The economic downturn has improved the labour supply of engineers and senior managers and has also improved BC Hydro's ability to attract and retain staff in a variety of roles. The economic situation has also had the effect of delaying employee retirements; however, this may result in a sudden surge of retirements in the future with shorter notice periods. Apprentice programs and contingent workers partially mitigate this risk. In addition, the return on pension fund assets and the market discount rate at year end can have a significant impact on the cost of providing employee future benefits.

Areas where BC Hydro is exposed to the risk of non-compliance with environmental regulations include the release of hazardous materials into the environment and endangerment of wildlife and their habitats. These risks are managed through a variety of site specific risk management strategies.

FUTURE OUTLOOK

The *Budget Transparency and Accountability Act* requires that BC Hydro file a Service Plan each year. BC Hydro's Service Plan filed in February 2011 forecasts net income for fiscal 2012 at $611 million. The Service Plan assumes a 9.73 per cent interim rate increase for fiscal 2012.

On March 1, 2011, BC Hydro filed its F2012-F2014 RRA with the BCUC, seeking approval for rate increases of 9.73 per cent for each of the next three years reflecting increasing capital-related costs, an increase in domestic energy costs and a reduction in forecast trade income. On April 21, 2011, the BCUC approved an interim rate increase of 8 per cent effective May 1, 2011 and suspended the regulatory review of the F2012-2014 RRA until the completion of a provincial government review of BC Hydro. The outcome of this review, along with changes in key assumptions such as water inflows, will be incorporated into an amended BC Hydro revenue requirements application to the BCUC, expected to be filed in late summer/early fall 2011.

BC Hydro's results 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 impact to net income of these non-controllable factors is largely mitigated through the use of regulatory accounts. The Service Plan forecast assumes average water inflows for fiscal 2012, customer load of 52,071 GWh, average market energy prices of CDN $34.00/MWh, short-term interest rates of 1.66 per cent and a U.S. dollar exchange rate of US$0.9861, an allowed return on equity of 14.38 per cent, and an interim rate increase of 9.73 per cent for fiscal 2012.

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 2012. 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.

The volatility between BC Hydro's plan and actual results are mostly mitigated through the use of BCUC-approved regulatory deferral accounts.

Factor	Change	Approximate change in earnings before regulatory deferral account transfers (in millions)	5 year high	5 year low
Hydro generation [1]	1,000 GWh	$ 35	52,140 GWh	39,303 GWh
Electricity trade margins	$1/MWh	35	n/a	n/a
Interest rates	+/- 1%	50	4.50% [2]	0.45% [2]
Exchange rates (US/ CDN)	$0.01	5	$1.10 [3]	$0.88 [3]
Weather	1°C change in average temperature	20	1.0°C [4]	-1.5 °C [4]
Pension costs	1% change in the expected return of 7.3% on pension assets [5]	5	19.2%	-23.3%

[1] *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).*

[2] *Interest rates are the average Canadian short-term interest rates (3 month Canadian Dollar Offered Rate).*

[3] *Exchange rates are the average US Dollar noon rates for F2007 to F2011.*

[4] *Weather high and low numbers represents the variance in degrees Celsius from the normal temperatures over the winter months November to March from 2006/07 to 2010/11. (-1.5 degrees lower than normal to 1.0 degrees higher than normal— normal is the 10-year rolling average).*

[5] *The impact of this change affects earnings in the subsequent year.*