THIRD QUARTER REPORT FISCAL 2009

British Columbia
The Best Place on Earth

BC hydro
FOR GENERATIONS

BC HYDRO & POWER AUTHORITY MANAGEMENT DISCUSSION AND ANALYSIS

The Management Discussion and Analysis reports on BC Hydro's consolidated results and financial position for the three and nine month periods ended December 31, 2008 (fiscal 2009). This section should be read in conjunction with the Management Discussion and Analysis presented in the 2008 Annual Report, the 2008 Annual Consolidated Financial Statements of BC Hydro, and the interim consolidated financial statements of BC Hydro for the three and nine month periods ended December 31, 2008 and 2007. 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 the third quarter of fiscal 2009 benefitted from increased trade income, but were adversely impacted by lower domestic revenues, higher energy costs, higher operating costs 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 three and nine month periods ended December 31, 2008 was $159 million and $369 million respectively, compared to $188 million and $350 million for the same periods in fiscal 2008.

- Results for the year reflect reduced demand from large industrial customers as a result of weakness primarily in the forestry sector. This was offset by very positive results from trading activities.

- Hydro generation levels in the third quarter were 16 per cent lower than in the prior year as a result of lower than average water 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 the reduced load.

- Property, plant and equipment expenditures for the year to date of $1,032 million are 31 per cent higher than the prior year ($788 million) primarily due to the Vancouver Island Transmission Reinforcement project, Revelstoke Unit 5 installation, Aberfeldie Redevelopment, 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 and maintain its aging infrastructure.

	For the three months ended December 31			*For the nine months ended December 31*		
(in millions)	**2008**	2007	Change	**2008**	2007	Change
Income Before Regulatory Accounts	**$ 17**	$ 159	$ (142)	**$ 83**	$ 456	$ (373)
Net Income	**$ 159**	$ 188	$ (29)	**$ 369**	$ 350	$ 19
Accrued Payment to the Province	**$ (14)**	$ 154	$ (168)	**$ 21**	$ 282	$ (261)
Number of Domestic Customers	**N/A**	N/A	N/A	**1,793,530**	1,758,958	34,572
GWh Sold (Domestic)	**13,705**	14,182	(477)	**37,994**	39,355	(1,361)
Total Reservoir Storage (GWh)	**N/A**	N/A	N/A	**23,807**	23,706	101

(in millions)	***As at December 31, 2008***	*As at March 31, 2008*	*Change*
Total Assets	**$ 15,129**	$ 13,909	$1,220
Retained Earnings	**$ 2,213**	$ 1,865	$ 348
Debt to Equity[1]	**80 : 20**	70 : 30	N/A

[1] Based on equity as defined for regulatory purposes, which changed by Order in Council from the Province effective April 1, 2008.

CONSOLIDATED RESULTS OF OPERATIONS

BC Hydro reports net income both before and after net transfers 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 (Net Income Before Regulatory Transfers) and under GAAP 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 (excluding 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 into income. As a result, there can be significant differences between net income before regulatory accounts and net income.

For the quarter ended December 31, 2008, income before regulatory accounts was $17 million compared to $159 million for the same period in fiscal 2008. The decrease was a result of lower domestic gross margin, arising from both lower domestic revenues and higher energy costs, higher operating costs and higher finance charges, partially offset by higher trade gross margin.

Transfers to regulatory accounts for the quarter were mainly comprised of transfers to the Heritage and Non-Heritage Deferral Accounts related to higher cost of energy than planned and transfer to the Trade Income Deferral Account for the variance between plan and actual trade income. Transfers for the quarter to these energy deferral accounts include the cumulative year to date adjustment to reflect the updated Revenue Requirements forecast filed with the British Columbia Utilities Commission (BCUC) on October 17, 2008, which reflected a higher trade income forecast and a lower load forecast for the fiscal year than compared to the Revenue Requirements Application (RRA) originally filed, and the rate increase request as per the Final Argument filed on November 21, 2008. Other transfers to regulatory accounts in the quarter included higher than planned foreign exchange gains and demand side management expenditures. In addition, the October update requested deferral of interest rate variances and the year to date adjustment has been reflected in the quarter.

Net income for the third quarter was $159 million, a decrease of $29 million from fiscal 2008. The decrease in net income from the prior year is mainly due to lower domestic gross margin and higher amortization expense and finance charges, partially offset by higher trade income and lower operating costs after deferral.

For the nine months ended December 31, 2008, income before regulatory accounts was $83 million compared to $456 million for the same period in fiscal 2008. The decrease was a result of lower domestic gross margin, primarily from higher energy costs, and higher operating costs related to maintenance of generating and distribution assets, including unexpected expenditures on the repair of a unit at the GM Shrum Generating Station, expenditures on strategic procurement and information technology initiatives, and higher finance charges, partially offset by higher trade income. Fiscal 2008 was a high water year and therefore cost of energy in that year was lower than normal due to more hydro generation which is generated at a lower cost.

Transfers to regulatory accounts for the year were mainly comprised of transfers to the Heritage and Non-Heritage Deferral Accounts due to higher cost of energy than planned, higher demand side management expenditures, investigation costs related to Site C, higher than planned foreign exchange gains on long-term debt and deferral of finance charges due to lower than planned interest rates.

Net income for the nine months ended December 31, 2008 was $369 million, compared with $350 million for the same period in fiscal 2008. The increase in net income from the prior year is mainly due to higher trade income and lower finance charges after deferral, partially offset by lower domestic gross margin and higher amortization expense.

REVENUES

For the three months ended December 31	$ in Millions		Gigawatt hours	
	2008	2007	**2008**	2007
Domestic				
Residential	**$ 342**	$ 335	**4,924**	5,059
Light industrial and commercial	**279**	265	**4,650**	4,610
Large industrial	**121**	132	**3,522**	3,873
Other energy sales	**21**	42	**609**	640
Total Domestic	**$ 763**	$ 774	**13,705**	14,182
Trade				
Electricity	**$ 357**	$ 234	**6,844**	8,026
Gas	**326**	230	**4,781**	4,071
Total Trade	**683**	464	**11,625**	12,097
Total	**$ 1,446**	$ 1,238	**25,330**	26,279

For the nine months ended December 31	$ in Millions		Gigawatt hours	
	2008	2007	**2008**	2007
Domestic				
Residential	**$ 850**	$ 813	**12,092**	12,131
Light industrial and commercial	**812**	776	**13,521**	13,546
Large industrial	**378**	392	**10,989**	11,560
Other energy sales	**59**	125	**1,392**	2,118
Total Domestic	**$ 2,099**	$ 2,106	**37,994**	39,355
Trade				
Electricity	**$ 1,220**	$ 850	**27,009**	31,352
Gas	**874**	551	**11,472**	10,097
Total Trade	**2,094**	1,401	**38,481**	41,449
Total	**$ 4,193**	$ 3,507	**76,475**	80,804

Total revenue for the three and nine months ended December 31, 2008 was $1,446 million and $4,193 million, an increase of $208 million and $686 million, respectively, over the same period last year. Trade revenues were higher as a result of higher average commodity prices, partially offset by lower trade volumes. Domestic revenues were lower in the quarter and flat year to date relative to the prior year due to higher average customer rates in all rate classes, offset by lower consumption by large industrial customers due to curtailments at some operations in the forestry and refining industries and losses on forward energy purchase contracts which are recorded in revenue.

Domestic Revenues

Total domestic revenues of $763 million for the third quarter were $11 million or 1 per cent lower than in the same period in the previous year. The decrease was mainly due to losses on hedging of forward energy purchase contracts, and lower consumption in the large industrial sector due to the closure of two pulp mills and shutdown of the newsprint, chemical pulp and cardboard lines at one mill. This was partially offset by higher average customer rates in all rate classes which were increased on an interim basis by 6.56 per cent on April 1, 2008 and an increase in the rate of customer growth.

Total domestic revenues of $2,099 million for the nine months ended December 31, 2008 were $7 million or 0.3 per cent lower than for the same period in the previous year. The decrease was mainly due to a 3 per cent decrease in domestic sales volumes due to lower usage, lower consumption in commercial and wood manufacturing sectors, lower consumption in the large industrial sector due to closures during the year of operations in the pulp and paper sector and losses on hedging of 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.

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 third quarter ended December 31, 2008 increased by $219 million due to both electricity and gas activities. The increase in trade electricity sales includes a decrease in forward electricity sales of $154 million, which are netted with forward purchases in revenue in accordance with GAAP, offset by a $123 million increase in spot electricity sales. Electricity revenues for the quarter reflect higher sales prices offset by a decrease in gross electricity sales volume of 15 per cent. The increase in the average gross electricity sales price was due largely to higher market prices in Alberta driven by generation outages throughout the quarter. Gas revenue increased in the quarter by $96 million largely driven by a 14 per cent increase in the average gross gas sales price and a 17 per cent increase in gross gas sales volume.

Trade revenues for the nine months ended December 31, 2008 increased by $693 million due to both electricity and gas activities. The increase in trade electricity sales includes a decrease in forward electricity sales of $438 million, which are netted with forward purchases in revenue in accordance with GAAP, offset by a $370 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 14 per cent. Gas revenues increased by $323 million reflecting an increase in gas sales prices as well as a 14 per cent increase in gas sales volumes. The increase in gas prices was driven by increased supply concerns in the current year while the increase in volume reflects 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 made up of the following sources of supply:

For the three months ended December 31	($ in millions) 2008	2007	(gigawatt hours) 2008	2007	($ per MWh) 2008[2]	2007[2]
Hydroelectric (Water Rentals)	**$ 84**	$ 84	**12,038**	14,337	**$ 6.93**	$ 5.75
Purchases from Independent Power Producers and other long-term contracts	**142**	130	**2,288**	2,200	**61.92**	59.22
Other electricity purchases - Domestic	**56**	12	**914**	217	**61.31**	55.05
Gas for thermal generation	**21**	12	**153**	97	**135.72**	123.05
Transmission charges and other expenses	**33**	13	**33**	30	**-**	-
Allocation to/from trade energy	**(14)**	(41)	**7**	(807)	**91.56**	54.43
Total Domestic	**$ 322**	$ 210	**15,433**	16,074	**$ 20.84**	$ 13.05
Other electricity purchases - Trade[1]	**$ 241**	$ 126	**6,789**	7,177	**$ 55.60**	$ 52.56
Remarketed gas	**288**	218	**4,843**	4,177	**59.56**	52.30
Transmission charges and other expenses	**64**	54	**-**	-	**-**	-
Allocation to/from domestic energy	**14**	41	**(7)**	807	**91.56**	54.43
Total Trade	**$ 607**	$ 439	**11,625**	12,161	**$ 64.00**	$ 56.77
Total Energy Costs	**$ 929**	$ 649	**27,058**	28,235	**$ 39.38**	$ 31.88

For the nine months ended December 31	($ in millions) 2008	2007	(gigawatt hours) 2008	2007	($ per MWh) 2008[2]	2007[2]
Hydroelectric (Water Rentals)	**$ 225**	$ 228	**31,825**	38,573	**$ 7.11**	5.89
Purchases from Independent Power Producers and other long-term contracts	**419**	357	**6,597**	5,965	**63.46**	59.80
Other electricity purchases - Domestic	**174**	40	**2,978**	776	**58.57**	51.47
Gas for thermal generation	**48**	34	**349**	322	**137.88**	105.28
Transmission charges and other expenses	**59**	46	**84**	79	**-**	-
Allocation to/from trade energy	**(14)**	(123)	**(49)**	(2,331)	**76.06**	55.45
Total Domestic	**$ 911**	$ 582	**41,784**	43,384	**$ 21.80**	$ 13.42
Other electricity purchases - Trade[1]	**$ 729**	$ 400	**26,651**	28,040	**$ 56.11**	$ 55.22
Remarketed gas	**845**	533	**11,676**	10,403	**72.35**	51.24
Transmission charges and other expenses	**222**	184	**-**	-	**-**	-
Allocation to/from domestic energy	**14**	123	**49**	2,331	**76.06**	55.45
Total Trade	**$ 1,810**	$1,240	**38,376**	40,774	**$ 66.87**	$ 58.59
Total Energy Costs	**$ 2,721**	$1,822	**80,160**	84,158	**$ 43.39**	$ 35.31

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.

Total energy costs for the third quarter of fiscal 2009 were $929 million, 43 per cent higher than the third quarter last year, primarily as a result of lower hydro generation which required higher purchases from IPPs and other market energy suppliers, and higher electricity trade prices and gas trade volumes and prices.

For the nine months ended December 31, 2008, total energy costs of $2,721 million were $899 million higher than the same period last year primarily due to lower hydro generation due to lower inflows and system constraints which required higher purchases from IPPs, higher market purchases, and higher electricity trade prices and gas trade volumes and prices.

Domestic Energy Costs

Domestic energy costs of $322 million in the third quarter of fiscal 2009 were $112 million or 53 per cent higher than the third quarter of fiscal 2008. The increase was due to increased volume of purchases of market electricity driven by lower water inflows year to date, and higher electricity prices. In fiscal 2008, BC Hydro experienced high water inflows and was therefore able to increase low-cost hydro generation and reduce market energy purchases, resulting in lower cost of energy.

Domestic energy costs of $911 million year to date were $329 million or 56 per cent higher than the nine months ended December 31, 2007. The increase was due to greater purchasing costs of energy due to higher purchase volumes and prices. Purchase volumes were increased due to lower than average reservoir inflows and system constraints such as the GM Shrum Generating Station unit outage. The price of electricity purchased was also relatively high, particularly early in the fiscal year.

Trade Energy Costs

Trade energy costs for the third quarter ended December 31, 2008 increased by $168 million primarily due to trade electricity and remarketed gas purchases. Spot electricity purchases increased by $115 million offsetting decreased forward purchases which are netted against forward sales according to GAAP and are excluded from trade energy costs. Remarketed gas costs increased by $70 million due to a 14 per cent increase in the average gross gas purchase price and a 16 per cent increase in gross gas purchase volumes.

Trade energy costs for the nine months ended December 31, 2008 increased by $570 million primarily due to trade electricity and remarketed gas purchases. The increase in trade electricity purchases includes a decrease in forward electricity purchases of $383 million, which are netted in revenue in accordance with GAAP, offset by a $329 million increase in spot electricity purchases. Electricity purchases for the year reflect a marginal increase in the average electricity purchase price offset by a decrease in electricity purchase volume. Remarketed gas costs increased by $312 million due to a 41 per cent increase in the average gross gas purchase price and a 12 per cent increase in gross gas purchase volumes. As with gas sales prices, gas purchase prices also increased based on supply concerns in the current year.

WATER INFLOWS

Water inflows into BC Hydro's reservoirs were 97 per cent of average in fiscal 2009, compared to fiscal 2008 which were 115 per cent of average (average from 1971-2000).

The BC Hydro reservoirs have been managed such that the combined storage in BC Hydro reservoirs at December 31, 2008 was 113 per cent of average, compared to 112 per cent of average at December 31, 2007 (average storage levels relate to the average from 1985-2007), with the Williston reservoir on the Peace River system at 111 per cent of average (fiscal 2008 –117 per cent), and the Kinbasket reservoir on the Columbia River system at 120 per cent of average (fiscal 2008 – 100 per cent).

OPERATING COSTS

Operations costs for the three and nine months ended December 31, 2008 were $12 million and $50 million higher than in the same period last year, primarily due to higher Site C costs as this project moved into its second stage in fiscal 2009, higher demand side management (DSM) costs and expenditures on the smart metering and infrastructure project (SMI) which both support energy conservation. All of these costs are transferred to regulatory accounts and do not impact current year net income.

Maintenance costs for the three and nine months ended December 31, 2008 were $10 million and $43 million higher than in the same period in the prior 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 during the first quarter, increased maintenance of distribution assets and routine vegetation work to improve system resiliency for the storm season and expenditures for penstock coatings and identification phase projects in fiscal 2009. The GM Shrum turbine failure resulted in significant unplanned major maintenance and related costs are therefore being transferred to the Heritage Deferral Account.

Administration costs for the three and nine months ended December 31, 2008 were $17 million and $32 million higher than in the same period in the prior year. The increase is primarily the result of expenditures for the strategic procurement and information technology initiatives.

AMORTIZATION EXPENSE

Amortization expense of $96 million for the third quarter was $10 million higher than the same period in the previous year mainly due to the one time gain on the sale of an ICG compressor that occurred in the third quarter of fiscal 2008 which reduced amortization expense in that year, and higher assets in service.

Amortization expense of $288 million for the nine months ended December 31, 2008 was $21 million higher than the same period in the previous year mainly due to the one time gain on the sale of an ICG compressor that occurred in fiscal 2008, and increased assets in service; partially offset by gains received from the sale of land in fiscal 2009, fewer project write offs, and lower contributions in aid (CIA) assets in service.

FINANCE CHARGES

Finance charges of $134 million for the third quarter were $18 million higher than the same period in the prior year due to translation losses due to the weakening of the Canadian dollar as compared to the US dollar, a higher average volume of debt, and lower sinking fund income. These negative variances were partially offset by lower short term interest rates, higher capitalized interest related to increased capital expenditures and a favourable mark-to-market adjustment on certain risk management activities.

Finance charges of $354 million for the nine months ended December 31, 2008, were $6 million higher than for the same period in the previous year. The increase is due to foreign exchange translation losses on net unhedged $US debt as a result of the weakening of the Canadian dollar as compared to the US dollar in the current year, a higher 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, higher capitalized interest related to increased capital expenditures and mark-to-market adjustments on certain risk management activities.

CHANGES IN ACCOUNTING STANDARDS

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*; (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.

(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.

(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.

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

CICA Section 3862 and 3863 replaces CICA Handbook Section 3861, *Financial Instruments – Disclosures and Presentation*, revising and enhancing disclosure requirements to provide additional information on the nature and extent of risks arising from financial instruments to which the entity is exposed and how it manages those risks.

FUTURE ACCOUNTING CHANGES

(a) International Financial Reporting Standards

The CICA will transition Canadian GAAP for publicly accountable entities to International Financial Reporting Standards ("IFRS"). The Company's consolidated financial statements are to be prepared in accordance with IFRS for the fiscal year commencing April 1, 2011. The Company is currently evaluating the impact of this standard 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. The Company is currently evaluating the impact of this standard on its consolidated financial statements.

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

Subsequent to quarter end, 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 to be applied retrospectively without restatement to prior periods. The Company will adopt this guidance in its March 31, 2009 annual financial statements and it is currently evaluating the impact on its consolidated financial statements.

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.

Diagnostic and assessment activities will continue until the end of the current fiscal year. The completion of topic-specific workshops will result in detailed assessments of potential impacts along with required changes to policies, processes and systems. An analysis of financial system impacts is also underway. Implementation activities will begin in earnest commencing in fiscal 2010.

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 as at December 31, 2008 is below 85 per cent due to the 80:20 cap.

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 only include 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.

POWEREX LEGAL PROCEEDINGS

Since 2000, Powerex, a wholly owned subsidiary of the Company, 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 U.S. 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 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. However, FERC has decided that CDWR transactions from October 2000 to June 2001 will be included in its refund inquiry, and that the issue of market manipulation will be excluded from the inquiry. The California parties have applied to FERC for a rehearing of this decision.

At December 31, 2008, Powerex was owed US $268 million (CDN $328 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.

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 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.

For the three and nine months ended December 31, 2008, BC Hydro transferred, on a net basis, $142 million and $286 million, respectively, to regulatory accounts, compared with the transfer of $29 million to and $106 million from the regulatory accounts during the same periods last year. The majority of the transfers relate to the cost of energy deferral accounts. The net balance in the regulatory asset and liability accounts as at December 31, 2008, was $858 million compared to $568 million at March 31, 2008.

The Heritage Deferral Account and Non-Heritage Deferral Account 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 (97 per cent of average), hydro generation was 3,422 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 $7.11 per MWh compared to the average cost of $58.57 per MWh for market purchases for the nine month period ended December 31, 2008.

Revenue Requirements Application (RRA)

BC Hydro filed its RRA for fiscal 2009 and fiscal 2010, with the BCUC on February 20, 2008. In this application BC Hydro originally sought a rate increase of 6.56 per cent effective April 1, 2008, and a further increase of 8.21 per cent to take effect on April 1, 2009. The main cost drivers for these rate increases are the increasing cost of energy purchases to meet domestic needs, the increased level of capital expenditures to upgrade and expand BC Hydro's system, and the inflationary and growth pressures on operating costs.

Requested rate increases require the approval of the BCUC. The BCUC approved an interim rate increase of 6.56 per cent effective April 1, 2008 as well as the applied for reduction in the deferral account rate rider from 2 per cent to 0.5 per cent for the purpose of recovering a portion of the current balances in the Heritage Deferral Account, Non-Heritage Deferral Account, Trade Income Deferral Account and BCTC Deferral Account. An Oral Hearing on the RRA was held in October 2008. BC Hydro filed an update with the BCUC on October 17, 2008, to reflect a higher trade income forecast, lower short-term interest rates and a lower load forecast based on more recent forecasts and year to date experiences. It also proposed regulatory accounts for non-current pension expense and interest rate variances from forecast. On November 21, 2008, BC Hydro filed its Final Argument, which proposed rate increases of 6.56 per cent for fiscal 2009 and 7.5 per cent for fiscal 2010. BC Hydro expects a decision on the RRA in the fourth quarter of fiscal 2009.

Long-Term Acquisition Plan (LTAP)

On June 12, 2008, BC Hydro filed the 2008 LTAP Application with the BCUC. The LTAP is an update to the 2006 Integrated Electricity Plan and is aligned with the BC Energy Plan, which was released in 2007. This 10-year action plan provides details on how BC Hydro expects to meet the growing demand for electricity in British Columbia with a focus on conservation and clean power sources. On December 22, 2008, BC Hydro filed an Evidentiary Update to its LTAP to address recent economic events and the resulting impacts on BC Hydro's load forecast and Demand Side Management Plan. In addition, information on BC Hydro's power acquisition was updated.

The demand-side management plan detailed in the LTAP includes conservation programs, changes in rate structures, and new regulatory codes and standards. Additional clean or renewable resource options – both large and small – are also being considered. The 2008 LTAP is subject to a public hearing that will begin in February 2009, with a final BCUC decision expected in the summer of 2009.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the third quarter was $166 million, compared with $293 million provided by operating activities for the same period last year. The decrease was primarily due to an increase in market energy purchases partially offset by a decrease in foreign exchange translation gains relative to the prior year.

For the nine months ended December 31, 2008, cash flow provided by operating activities was $229 million, compared with $588 million for the same period last year, with the decrease due to increased market energy purchases and changes in working capital, partially offset by foreign exchange translation losses and losses on mark-to-market.

The net long term debt balance at December 31, 2008 was $9,041 million, compared with $7,541 million at March 31, 2008. The increase was a result of net long term bond issues totaling $258 million, an increase in revolving borrowings of $440 million, an increase of $70 million in debt due to fair value adjustments resulting from fair value hedges, net foreign exchange revaluation losses of $225 million and withdrawals of $507 million in sinking funds.

PROPERTY, PLANT AND EQUIPMENT EXPENDITURES

Property, plant and equipment expenditures were as follows:

	For the three months ended December 31[1]		*For the nine months ended December 31*[1]	
(in millions)	**2008**	2007	**2008**	2007
Distribution improvements and expansion	**$ 108**	$ 109	**$ 303**	$ 274
Generation replacements and expansion	**81**	89	**254**	226
Transmission lines and substation replacements & expansion	**156**	64	**383**	205
General, including computers and vehicles	**34**	28	**92**	83
	$ 379	$ 290	**$ 1,032**	$ 788

[1] Includes Intangible assets

For the three month period ended December 31, 2008, distribution improvements and expansion expenditures are consistent with the prior year. Generation replacements and expansion expenditures are lower when compared to the prior year due to lower spending on Revelstoke Unit 5 Installation and Aberfeldie Redevelopment during the quarter reflecting different phases of the projects; partially offset by increased spending on the Cheakamus Spillway Gate Reliability project. The increase in transmission activity during the quarter is mainly due to higher expenditures on the Vancouver Island Transmission Reinforcement project, the 500kV Circuit Breaker Replacement project (at Ingledow), and various IPP projects. General expenditures are higher mainly a result of increased spending on corporate facility and field building improvements and security improvements.

The increase in distribution improvements and expansion capital expenditures for the nine month period ended December 31, 2008, is primarily due to increased system improvement expenditures and system resiliency work. Generation replacements and expansion expenditures have increased mainly as a result of increased spending on the Revelstoke Unit 5 installation, the Aberfeldie Redevelopment, and the Cheakamus Spillway Gate Reliability project. These increases are partially offset by lower spending on the John Hart Spillway Gate Reliability project, and the GM Shrum Unit 6 & 7 Rotor Pole Replacement project. The increase in transmission activity is mainly due to higher expenditures on the Vancouver Island Transmission Reinforcement project, the Kinder Morgan TMX1 project and various IPP related projects. These increases are partially offset by lower expenditures on the Terasen TMPSE project, and the Gibraltar Mine Load Increase projects. The increase in general capital expenditures is primarily due to a greater number of vehicle purchases.

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 acceptable levels which are commensurate with potential benefits to be derived. While risks cannot be eliminated, BC Hydro's strategies aim to minimize or mitigate them with a specific 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 overseeing the identification and assessment of significant risks and ensuring 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.

The amount of energy stored in BC Hydro system reservoirs continues to be above average and the system as a whole is expected to transition from a net energy deficit position to a net surplus position under average water conditions over the next couple of fiscal years. However, several factors constrain BC Hydro's ability to use its stored system energy to meet load throughout the year. These factors include potential generating unit outages at major plants (forced outages and capital projects) as well as downstream constraints which limit generation at major plants during some periods. As a result, even when the system has an annual energy surplus, some electricity purchases may still be required during constrained periods of the year (e.g. fall, winter, early spring), while electricity sales may be needed during other periods to avoid spill from system reservoirs.

Driven largely by a downturn in the industrial sector, in fiscal 2009, BC Hydro's demand growth is tracking lower than projected. The recent volatile economic and market conditions could further impact customer loads and the creditworthiness of customers and suppliers. In addition, based on the recent 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 2010. 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.

Management's assessment of risk is continuous. Other risks to BC Hydro have not changed materially from the Management Discussion and Analysis in the 2008 Annual Report.

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 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 forecasts income before regulatory accounts of $3 million and net income forecast at $357 million.

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 forecast assumed average water inflows, customer load of 54,791 GWh, average market energy prices of US$59.72/MWh, short-term interest rates of 4.68 per cent and a US dollar exchange rate of US$0.9864 for fiscal 2009, and an interim rate increase of 6.56 per cent approved by the BCUC.

The significant changes from the Service Plan for fiscal 2009 include:
- An increase in domestic energy costs resulting from a drier than expected summer and fall. As a result, energy market purchases have been increased and low cost hydro-generation has been reduced to conserve reservoir levels.
- A decrease in customer load of 2,158 GWh for total customer load of 52,633 GWh. This decrease is largely a result of the economic slowdown and an increase in expected savings from conservation measures.
- A decrease in short term interest rates to 2.14 per cent which has resulted in lower finance charges.
- An increase in trade income resulting from short-term market opportunities experienced earlier in the year.

As most of these changes from the Service Plan relate to items that flow through existing or proposed regulatory deferral accounts for future recovery/refund from/to ratepayers, net income for fiscal 2009 in the current forecast is similar to the 2008 Service Plan.

A decision from the BCUC on BC Hydro's proposed rate increase of 6.56 per cent and 7.5 per cent for fiscal 2009 and fiscal 2010 respectively is pending and is expected in the fourth quarter of 2009.

FINANCIAL STATEMENTS

CONSOLIDATED STATEMENT OF OPERATIONS

(Unaudited)	*For the three months ended December 31*		*For the nine months ended December 31*	
(in millions)	**2008**	2007	**2008**	2007
Revenues				
Domestic	**$ 763**	$ 774	**$2,099**	$ 2,106
Trade	**683**	464	**2,094**	1,401
	1,446	1,238	**4,193**	3,507
Expenses				
Energy Costs:				
Domestic	**322**	210	**911**	582
Trade	**607**	439	**1,810**	1,240
Operations	**87**	75	**250**	200
Maintenance	**94**	84	**265**	222
Administration	**48**	31	**108**	76
Taxes	**41**	38	**124**	116
Amortization	**96**	86	**288**	267
	1,295	963	**3,756**	2,703
Operating Income	**151**	275	**437**	804
Finance Charges	**134**	116	**354**	348
Income Before Regulatory Accounts	**17**	159	**83**	456
Net Change in Regulatory Accounts (note 5)	**142**	29	**286**	(106)
Net Income	**$ 159**	$ 188	**$ 369**	$ 350

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(Unaudited)	*For the three months ended December 31*		*For the nine months ended December 31*	
(in millions)	**2008**	2007	**2008**	2007
Net Income	**$ 159**	$ 188	**$ 369**	$ 350
Other Comprehensive Income (Loss) (note 8)	**(69)**	15	**(74)**	81
Comprehensive Income	**$ 90**	$ 203	**$ 295**	$ 431

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

(Unaudited)	*For the nine months ended December 31*	
(in millions)	**2008**	2007
Retained Earnings, Beginning of Period	**$1,865**	$ 1,784
Net Income	**369**	350
Accrued Payment to the Province	**(21)**	(282)
Retained Earnings, End of Period	**$2,213**	$ 1,852

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED BALANCE SHEET

(Unaudited) *(in millions)*	***As at December 31 2008***	*As at March 31 2008*
ASSETS		
Property, Plant and Equipment, net	**$ 11,486**	$ 10,746
Current Assets		
Cash and cash equivalents	**250**	22
Current portion of sinking funds	**2**	506
Accounts receivable and accrued revenue	**690**	538
Inventories (note 3)	**177**	83
Prepaid expenses	**63**	99
Current portion of derivative financial instrument assets	**158**	60
	1,340	1,308
Other Assets and Deferred Charges		
Intangible assets	**400**	411
Sinking funds	**108**	89
Employee future benefits	**322**	299
Regulatory assets (note 5)	**1,216**	929
Derivative financial instrument assets	**257**	127
	2,303	1,855
	$ 15,129	$ 13,909
LIABILITIES AND EQUITY		
Long-term debt net of sinking funds	**$ 6,965**	$ 6,957
Sinking funds presented as assets	**108**	89
Long-Term Debt	**7,073**	7,046
Current Liabilities		
Current portion of long-term debt, net of short-term sinking fund	**2,076**	584
Current portion of sinking funds presented as assets	**2**	506
Current portion of Long-Term Debt	**2,078**	1,090
Accounts payable and accrued liabilities	**1,017**	1,281
Current portion of derivative financial instrument liabilities	**177**	76
	1,194	1,357
Other Liabilities		
Regulatory liabilities (note 5)	**358**	361
Deferred contributions	**1,039**	982
Derivative financial instrument liabilities, long-term	**187**	192
Other long-term liabilities	**1,005**	960
	2,589	2,495
Shareholder's Equity		
Retained Earnings	**2,213**	1,865
Accumulated other comprehensive income (note 8)	**(18)**	56
	2,195	1,921
	$ 15,129	$ 13,909

Commitments and Contingencies (note 9)

See accompanying notes to the interim consolidated financial statements.

Approved on behalf of the Board:

Mossadiq S. Umedaly
Chair

Tracey L. McVicar
Chair, Audit and Risk Management Committee

CONSOLIDATED STATEMENT OF CASH FLOWS

(Unaudited)	*For the three months ended December 31*		*For the nine months ended December 31*	
(in millions)	**2008**	2007	**2008**	2007
Operating Activities				
Net income	**$ 159**	$ 188	**$ 369**	$ 350
Regulatory account transfers (note 5)	**(166)**	(52)	**(328)**	47
Adjustments for non-cash items:				
Amortization of regulatory accounts (note 5)	**13**	24	**42**	64
Amortization expense	**96**	86	**288**	267
Foreign exchange translation (gains) losses	**23**	(1)	**28**	(23)
Unrealized (gains) losses on mark-to-market	**19**	28	**24**	9
Other non-cash items	**25**	15	**9**	14
	169	288	**432**	728
Working capital changes	**(3)**	5	**(203)**	(140)
Cash provided by operating activities	**166**	293	**229**	588
Investing Activities				
Property, plant and equipment and intangible asset expenditures	**(384)**	(294)	**(1,036)**	(790)
Deferred contributions	**26**	28	**81**	78
Other items	**(6)**	(2)	**(12)**	(10)
Cash used in investing activities	**(364)**	(268)	**(967)**	(722)
Financing Activities				
Bonds				
Issued	**150**	-	**352**	830
Retired	**-**	-	**(94)**	(541)
Revolving borrowings	**239**	4	**440**	157
Sinking fund withdrawals	**(1)**	-	**507**	143
Settlement of derivative instruments	**34**	-	**49**	(94)
Payment to the Province	**-**	-	**(288)**	(331)
Cash provided by financing activities	**422**	4	**966**	164
Increase in cash and cash equivalents	**224**	29	**228**	30
Cash and cash equivalents, beginning of period	**26**	9	**22**	8
Cash and Cash Equivalents, End of Period	**$ 250**	$ 38	**$ 250**	$ 38
Supplemental Disclosure of Cash Flow Information				
Interest paid	**$ 132**	$ 140	**$ 383**	$ 392

See accompanying notes to the interim consolidated financial statements.

NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED) DECEMBER 31, 2008

DESCRIPTION

British Columbia Hydro and Power Authority (BC Hydro), was established in 1962 as a Crown Corporation of the Province of British Columbia (the Province) by enactment of the *Hydro and Power Authority Act*. As directed by the *Hydro and Power Authority Act*, BC Hydro's mandate is to generate, manufacture, distribute and supply power. BC Hydro's corporate purpose is to provide "Reliable power, at low cost, for generations." BC Hydro is subject to regulation (see note 5) by the British Columbia Utilities Commission (BCUC) which, among other things, approves the rates BC Hydro charges for its services.

BC Hydro owns and operates electric generation and distribution facilities in the Province. BC Hydro also owns transmission facilities in the Province that are operated by British Columbia Transmission Corporation (BCTC), an independent Crown Corporation of the Province.

NOTE 1: ACCOUNTING POLICIES

The interim consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP) for preparation of interim financial statements and do not conform in all respects to the disclosure requirements for annual financial statements. BC Hydro follows certain accounting practices that reflect the effects of regulation, and differ from the accounting practices for enterprises that do not operate in a rate-regulated environment. These interim consolidated financial statements and the notes should be read in conjunction with the Annual Consolidated Financial Statements and accompanying notes in BC Hydro's 2008 Annual Report.

Except for the changes described in note 2, these interim consolidated financial statements follow the same accounting policies as those described in BC Hydro's 2008 Annual Report.

Certain figures for the previous period have been reclassified to conform to the presentation in the current period.

NOTE 2: CHANGES IN ACCOUNTING STANDARDS

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*; (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.

(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 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 3 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. These recommendations did not have any impact on the Company's interim financial results. The incremental disclosures required as a result of adopting these Sections can be found in note 10. The transitional provisions provide that certain of the incremental disclosures need not be provided on a comparative basis in the year of adoption.

Future Accounting Changes

(a) International Financial Reporting Standards

The CICA will transition Canadian GAAP for publicly accountable entities to International Financial Reporting Standards ("IFRS"). The Company's consolidated financial statements are to be prepared in accordance with IFRS for the fiscal year commencing April 1, 2011. The Company is currently evaluating the impact of this standard 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. The Company is currently evaluating the impact of this standard on its consolidated financial statements.

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

Subsequent to quarter end, 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 to be applied retrospectively without restatement to prior periods. The Company will adopt this guidance in its March 31, 2009 annual financial statements and it is currently evaluating the impact on its consolidated financial statements.

NOTE 3: INVENTORIES

(in millions)	***As at December 31 2008***	*As at March 31 2008*
Materials and supplies	**$ 73**	$ 69
Natural gas trading inventories	**104**	14
	$177	$ 83

Effective April 1, 2008, the Company retrospectively adopted CICA Handbook Section 3031, *Inventories*, with reclassification of comparative prior period amounts. This new section requires that certain major spare parts and standby equipment be reclassified from inventory to property, plant and equipment. The new Handbook section also allows previously recorded impairment losses taken on inventory to be reversed if there is evidence that the net realizable value has subsequently recovered. Materials and supplies inventories are carried at cost and during the quarter ended December 31, 2008 there were no write downs recorded to reduce these inventory items to their net realizable value. Due to significant decreases in forward gas prices, natural gas trading inventories were carried at net realizable value in the third quarter.

The Company already includes certain major spare parts as property, plant and equipment and depreciates these assets over their useful lives. To meet the requirements of the new section, on adoption the Company reclassified approximately $55 million in asset components previously classified as materials and supplies to property, plant and equipment, and this is reflected in the March 31, 2008 comparative figures.

NOTE 4: SEASONALITY OF OPERATING RESULTS

Due to the seasonal nature of BC Hydro's operations, the interim consolidated statement of operations is not indicative of operations on an annual basis. Seasonal impacts of weather, including its impact on water inflows, energy consumption within the region and market prices of energy, can have a significant impact on BC Hydro's operating results.

NOTE 5: REGULATION

BC Hydro is regulated by the BCUC, and both entities are subject to general or special directives and directions issued by the Province. BC Hydro operates primarily under a cost of service regulation as prescribed by the BCUC. Orders in Council from the Province establish the basis for determining BC Hydro's equity for regulatory purposes, as well as its allowed return on equity and the annual payment to the Province. Calculation of its revenue requirements and rates charged to customers are established through applications filed with and approved by the BCUC.

BC Hydro applies various accounting policies that differ from GAAP for enterprises that do not operate in a rate-regulated environment. Generally, these policies result in deferral and amortization of costs and recoveries to allow for adjustment of future rates. In the absence of rate-regulation, these amounts would otherwise be included in the determination of net income in the period the amounts are incurred. These accounting policies support BC Hydro's regulation and have been established through ongoing application to and approval by the BCUC. To the extent that a deferral account has been, or will be applied for, and in management's estimate acceptance of deferral treatment by the BCUC is considered probable, the Company will defer such costs in advance of a final decision of the BCUC. Should the BCUC deny the application for regulatory treatment, the amount deferred would be recorded in net income at such time.

BC Hydro's Revenue Requirements Application (RRA) for fiscal 2009 and 2010 was filed with the BCUC on February 20, 2008. BCUC approved an interim rate increase of 6.56 per cent effective April 1, 2008 as well as the applied for reduction in the deferral account rate rider from 2 per cent to 0.5 per cent for the purpose of recovering a portion of the current balances in the Heritage Deferral Account, Non Heritage Deferral Account, Trade Income Deferral Account and the BCTC Deferral Account.

On October 17, 2008, BC Hydro filed an update to its RRA to reflect an increase in the trade income forecast, lower domestic demand, lower energy costs, and lower short-term interest rates. On November 21, 2008, BC Hydro filed its Final Argument, which proposed rate increases of 6.56 per cent for fiscal 2009 and 7.5 per cent for fiscal 2010 and a reduction in the rate rider in F2010 from 0.5 per cent to 0 per cent. The final rate increase is pending approval from the BCUC. BC Hydro expects a decision on the RRA in the fourth quarter of fiscal 2009. Results for the three and nine month periods ended December 31, 2008, reflect these applied for changes with the cumulative impact of such changes being recorded as a change in estimate in the third quarter.

Regulatory Accounts

The following regulatory assets and liabilities have been established through rate regulation. For the three and nine months ended December 31, 2008, the impact of regulatory accounting has resulted in an increase to net income of $142 million and $286 million respectively (three and nine months ended December 31, 2007 – $29 million increase and $106 million decrease respectively).

(in millions)	*April 1 2008*	*Addition (Reduction)*	*Amortization*	*Net Change*	*December 31 2008*
Regulatory Assets					
Heritage Deferral Account	$ 78	$ 232	$ (17)	$ 215	$ 293
Non-Heritage Deferral Account	52	(13)	(11)	(24)	28
BCTC Deferral Account	21	(3)	(5)	(8)	13
Demand-Side Management Programs	309	51	(31)	20	329
First Nation Negotiations, Litigation and Settlement Costs	360	21	(4)	17	377
Other Regulatory Accounts	113	58	5	63	176
Total Regulatory Assets	$ 933	$ 346	$ (63)	$ 283	$1,216
Regulatory Liabilities					
Future Removal and Site Restoration Costs	$ 192	$ -	$ (16)	$ (16)	$ 176
Trade Income Deferral Account	103	19	(22)	(3)	100
Foreign Exchange Gains and Losses	66	(28)	17	(11)	55
Interest Rate Deferral Account	-	27	-	27	27
Total Regulatory Liabilities	$ 361	$ 18	$ (21)	$ (3)	$ 358
Net	$ 572	$ 328	$ (42)	$ 286	$ 858

BC Hydro has applied to the BCUC for approval to establish new regulatory accounts for capital project investigation costs that would otherwise be expensed and variances between plan and actual taxes. Application was also made to allow variances between plan and actual major storms costs to be deferred in the non-heritage deferral account, to establish a new regulatory account to capture variances from forecast relating to interest rate changes and for deferral of Strategic Procurement project costs incurred in fiscal 2009. BC Hydro also intends to seek approval to defer all fiscal 2009 costs of the Smart Metering and Infrastructure project. The balance related to these proposed regulatory accounts are included in Other Regulatory Accounts and total $48 million as at December 31, 2008.

The RRA also proposed the establishment of a new regulatory account to capture load variances from forecast. No amount has been deferred with respect to this proposed regulatory account at December 31, 2008.

NOTE 6: CAPITAL MANAGEMENT

Orders in Council from the Province establish the basis for determining BC Hydro's equity for regulatory purposes, as well as its allowed return on equity and the annual Payment to the Province. Capital requirements are consequently managed through the retention of equity subsequent to the Payment to the Province and the imposed requirement of maintaining a debt to equity ratio not exceeding 80:20.

BC Hydro monitors its capital structure on the basis of its debt to equity ratio. For this purpose, BC Hydro defines debt as revolving borrowings and interest-bearing borrowings less investments held in sinking funds and temporary investments. Effective April 1, 2008 equity for regulatory purposes comprises retained earnings and accumulated other comprehensive income. In the prior year, equity for regulatory purposes comprised retained earnings, deferred revenue, contributions arising from the Columbia River Treaty and contributions in aid of construction. The change was enacted by the Province on January 17, 2008.

BC Hydro manages its capital so as not to exceed the 80:20 debt to equity ratio as defined by the Province. During the period, there were no changes in this approach to capital management.

The debt to equity ratio, based on equity as defined for regulatory purposes, at December 31, 2008 and March 31, 2008 was as follows:

(in millions)	***As at December 31 2008***	*As at March 31 2008*
Total long-term debt, net of sinking funds	**$ 9,041**	$ 7,541
Less: cash and cash equivalents	**(250)**	(22)
Net Debt	**$ 8,791**	$ 7,519
Retained earnings	**2,213**	1,865
Accumulated other comprehensive income	**(18)**	56
Deferred revenue	**-**	353
Contributions from the Columbia River Treaty	**-**	157
Contributions in aid of construction	**-**	825
Total Equity	**$ 2,195**	$ 3,256
Net Debt to Equity Ratio for Regulatory Purposes	**80 : 20**	70 : 30

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 year to date at December 31, 2008, is below 85 per cent of BC Hydro's distributable surplus due to the 80:20 cap.

NOTE 7: EMPLOYEE FUTURE BENEFITS

BC Hydro's cost for employee future benefits for the three and nine months ended December 31, 2008 was $7 million and $25 million respectively (2007 – $11 million and $33 million).

NOTE 8: OTHER COMPREHENSIVE INCOME AND ACCUMULATED OTHER COMPREHENSIVE INCOME

Other Comprehensive Income

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2008**	2007	**2008**	2007
Other Comprehensive Income				
Unrealized gain (loss) on sinking fund balances	**$ -**	$ 6	**$ -**	$ (4)
Reclassification to income of loss on sinking funds	**-**	(2)	**-**	3
Unrealized gain (loss) on derivatives designated as cash flow hedges	**105**	2	**135**	(96)
Reclassification to income of (gain) loss on derivatives designated as cash flow hedges	**(174)**	9	**(209)**	178
Other Comprehensive Income	**$ (69)**	$ 15	**$ (74)**	$ 81

Accumulated Other Comprehensive Income

(in millions)	*For the nine months ended December 31* **2008**	2007
Accumulated other comprehensive income (loss), beginning of period	**$ 56**	$ (20)
Other comprehensive income (loss) for the period	**(74)**	81
Accumulated Other Comprehensive Income (Loss), End of Period	**$ (18)**	$ 61

NOTE 9: COMMITMENTS AND CONTINGENCIES

Legal Proceedings

Since 2000, Powerex, a wholly owned subsidiary of the Company, 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 U.S 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 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. However, FERC has decided that CDWR transactions from October 2000 to June 2001 will be included in its refund inquiry, and that the issue of market manipulation will be excluded from the inquiry. The California parties have applied to FERC for a rehearing of this decision.

At December 31, 2008, Powerex was owed US $268 million (CDN $328 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.

NOTE 10: FINANCIAL INSTRUMENTS

Financial Risks

BC Hydro is exposed to a number of financial risks in the normal course of its business operations, including market risks resulting from fluctuations in commodity prices, interest rates and foreign currency exchange rates, as well as credit risks and liquidity risks. The nature of the financial risks and BC Hydro's strategy for managing these risks has not changed significantly from the prior period.

The following discussion is limited to the nature and extent of risks arising from financial instruments, as defined under Section 3862. However, for a complete understanding of the nature and extent of risks BC Hydro is exposed to, this note should be read in conjunction with BC Hydro's discussion of Risk Management found in the Management Discussion and Analysis section of the 2008 Annual Report.

(a) Credit Risk

Credit risk refers to the risk that one party to a financial instrument will cause a financial loss for the other party by failing to discharge an obligation. BC Hydro is exposed to credit risk related to cash and cash equivalents, short-term and long-term investments, and derivative instruments. It is also exposed to credit risk related to accounts receivable arising from its day to day electricity and natural gas sales in and outside British Columbia. Credit risk with respect to financial assets is limited to the carrying amount presented on the balance sheet. BC Hydro manages this risk through Board-approved credit risk management policies which contain limits and procedures to the selection of counter-parties. Exposures to credit risks are monitored on a regular basis.

(b) Liquidity Risk

Liquidity risk refers to the risk that BC Hydro will encounter difficulty in meeting obligations associated with financial liabilities. BC Hydro manages liquidity risk by forecasting cash flows to identify financing requirements and by maintaining committed credit facilities. BC Hydro's long-term debt comprises bonds and debentures and revolving borrowings obtained under an agreement with the Province. Cash from operations reduces BC Hydro's liquidity risk. BC Hydro does not believe that it will encounter difficulty in meeting its obligations associated with financial liabilities.

Through March 31, 2008, BC Hydro was subject to an overall borrowing limit imposed by legislation, dating back to March 1984, of $8,800 million dollars, net of sinking funds as defined by the *Hydro Power and Authority Act*. This limit was repealed effective May 1, 2008.

(c) Market Risks

Market risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: currency risk, interest rate risk, and price risk, such as changes in commodity prices and equity values. BC Hydro monitors its exposure to market fluctuations and may use derivative contracts to manage these risks, as it considers appropriate. Other than in its energy trading subsidiary Powerex, BC Hydro does not use derivative contracts for trading or speculative purposes.

i. Currency Risk

Currency risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in foreign exchange rates. BC Hydro's currency risk is primarily with the US dollar.

The majority of BC Hydro's currency risk arises from long-term debt in the form of US dollar denominated bonds. Energy commodity prices are also subject to currency risk as they are primarily denominated in US dollars. As a result, BC Hydro's trade revenues and purchases of energy commodities, such as electricity and natural gas, and associated accounts receivable and accounts payable, are affected by the Canadian/US dollar exchange rate. In addition, all commodity derivatives and contracts priced in US dollars are also affected by the Canadian/US dollar exchange rate.

BC Hydro actively manages its currency risk through a number of Board-approved policy documents. BC Hydro uses cross currency swaps and forward foreign exchange purchase contracts to achieve and maintain the Board-approved US dollar exposure targets.

ii. Interest Rate Risk

Interest rate risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. BC Hydro is exposed to changes in interest rates primarily through its variable rate debt and the active management of its debt portfolio including its related sinking fund assets and temporary investments. BC Hydro Board-approved debt management strategies include maintaining a percentage of variable interest rate debt within a certain range. BC Hydro enters into interest rate swaps to achieve and maintain the target range of variable interest rate debt.

iii. Commodity Price Risk

BC Hydro is exposed to commodity price risk as fluctuations in electricity prices and natural gas prices could have a materially adverse effect on its financial condition. Prices for electricity and natural gas fluctuate in response to changes in supply and demand, market uncertainty, and a variety of other factors beyond BC Hydro's control.

BC Hydro enters into derivative contracts to manage commodity price risk. Risk management strategies, policies and limits are designed to ensure BC Hydro's risks and related exposures are aligned with the Company's business objectives and risk tolerance. Risks are managed within defined limits that are regularly reviewed by the Board of Directors.

Financial Instruments, Interest and Other Income and Expense

The following table provides a comparison of carrying values and fair values for non-derivative financial instruments as at December 31, 2008:

	As at December 31, 2008		*Interest Income (Expense) recognized into income*	
(in millions)	Carrying Value	Fair Value	*For the three months ended December 31*	*For the nine months ended December 31*
Held for Trading:				
Cash and cash equivalents	$ 250	$ 250	$ 1	$ 2
Revolving borrowings – Cdn	(1,424)	(1,424)	(8)	(21)
Revolving borrowings – US	(12)	(12)	-	-
Receivables:				
Accounts receivable and accrued revenues	$ 690	$ 690	$ -	$ -
Available for Sale:				
Sinking funds – US	$ 2	$ 2	$ -	$ -
Held to Maturity:				
Sinking funds – US	$ 108	$ 133	$ 2	$ 4
Other Financial Liabilities:				
Accounts payable and accrued liabilities	$ (1,017)	$ (1,017)	$ -	$ -
Long-term debt (including current portion due in one year)	(7,715)	(9,310)	(120)	(357)

For non-derivative financial assets and liabilities classified as held-for-trading, loans and receivables, available-for-sale, held-to-maturity and other financial liabilities, no amount has been recognized in net income for the period relating to changes in fair value. For loans and receivables, the carrying value approximates fair value and amortized cost due to the short term nature of these financial instruments. For available-for-sale financial assets, no amount has been recorded in other comprehensive income and no amount was removed from other comprehensive income and reported in net income for the period.

The fair value of derivative instruments, designated or not designated as hedges, was as follows:

	As at December 31, 2008	
(in millions)	Carrying Value	Fair Value
Designated Hedges Used to Manage Risk Associated with Long-Term Debt		
Foreign currency contracts (cash flow hedges for $US denominated long-term debt)	$ (12)	$ (12)
Interest rate swaps (fair value hedges for debt)	93	93
Non-Designated Hedges		
Foreign currency contracts	$ 3	$ 3
Commodity derivatives	(29)	(29)
Embedded derivatives	(4)	(4)

As at December 31, 2008 there were no non-designated interest rate swaps.

For the three and nine months ended December 31, 2008, a loss of $1 million and a loss of $2 million respectively was recognized in operations related to the ineffective portion of designated cash flow hedges and fair value hedges. For designated cash flow hedges for the three and nine months ended December 31, 2008, a gain of $105 million and a gain of $135 million respectively was recognized in other comprehensive income. For the three and nine months ended December 31, 2008, $174 million and $209 million respectively was removed from other comprehensive income and reported in net income, offsetting foreign exchange losses recorded in the third quarter and for the nine month period.

For derivatives not designated as hedging instruments, an immaterial amount was recognized in domestic revenue for the three and nine months ended December 31, 2008 with respect to operational hedges and embedded derivatives. An immaterial amount and a gain of $1 million respectively was recognized in finance charges for the three and nine months ended December 31, 2008 with respect to foreign currency contracts for cash management purposes. A gain of $41 million and a gain of $92 million respectively was recorded in trade revenue for the three and nine months ended December 31, 2008 with respect to commodity derivatives.

(in millions)	***As at December 31 2008***
Derivatives Represented by:	
Derivatives designated as hedges	$ 81
Derivatives not designated as hedges	$ (30)
	$ 51

Fair Values

Refer to Fair Value in note 1: Significant Accounting Policies in the 2008 BC Hydro Annual Report for the basis for determining fair values.

Credit Risk

The carrying amount of financial assets presented above represents the maximum credit exposure as at December 31, 2008.

Domestic Electricity Receivables

A customer application and a credit check are required prior to initiation of services. For customers with no BC Hydro credit history, call centre agents ensure accounts are secured either by a credit bureau check, a cash security deposit, or a credit reference letter.

The value of domestic and trade accounts receivable, by age and the related bad debt provision are presented in the following tables.

Domestic and Trade Accounts Receivable Net of Allowance for Doubtful Accounts

	As at December 31
(in millions)	***2008***
Current	$ 457
Past due (30-59 days)	14
Past due (60-89 days)	3
Past due (more than 90 days)	3
	477
Allowance for doubtful accounts	(6)
	$ 471

At the end of each reporting period a review of the provision for bad and doubtful accounts is performed. It is an assessment of the potential amount of domestic and trade accounts receivable which will not be paid by customers after the balance sheet date. The assessment is made by reference to age, status and risk of each receivable, current economic conditions, and historical information. There was no change to the allowance for doubtful accounts during the nine months ended December 31, 2008.

Financial Assets Arising From BC Hydro's Trading Activities

A substantial majority of BC Hydro's counterparties associated with its trading activities are in the energy sector. This industry concentration has the potential to impact the Company's overall exposure to credit risk in that the counterparties may be similarly affected by changes in economic, regulatory, political and other factors. The Company manages credit risk by authorizing trading transactions within the guidelines of the Company's risk management policies, by monitoring the credit risk exposure and credit standing of counterparties on a regular basis and by obtaining credit assurances from counterparties to which they are entitled under contract.

With respect to these financial assets, BC Hydro assigns credit limits for counterparties based on evaluations of their financial conditions, net worth, regulatory environment, cost recovery mechanisms, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically and a detailed credit analysis is performed at least annually. Further, BC Hydro has tied a portion of its contracts to master agreements that require security in the form of cash or letters of credit if current net receivables and replacement cost exposure exceed contractually specified limits. The following table outlines the distribution, by credit rating, of financial assets that are neither past due nor impaired:

	Investment Grade	Unrated	Non-investment Grade	Total
	%	%	%	%
Accounts receivable	77	20	3	100
Assets arising from trading activities	84	16	0	100

The outstanding amount of collateral received from customers at December 31, 2008 was $13 million.

Liquidity Risk

The following table details remaining contractual maturities at December 31, 2008 of BC Hydro's non-derivative financial liabilities and derivative financial liabilities, which are based on contractual undiscounted cash flows. Interest payments have been computed using contractual rates or, if floating, based on rates current at December 31, 2008. In respect of the cash flows in U.S. dollars, the exchange rate as at December 31, 2008 has been used.

(in millions)	*Carrying Value*	*Fiscal 2009* *(3 months)*	*Fiscal 2010*	*Fiscal 2011*	*Fiscal 2012*	*Fiscal 2013*	*Fiscal 2014* *and thereafter*
Non-Derivative Financial Liabilities							
Total trade and other payables (excluding interest accruals)	$ 815	$ (728)	$ (63)	$ (10)	$ (4)	$ (1)	$ (11)
Bank overdrafts	62	(62)	-	-	-	-	-
Payment to the Province	21	-	(21)	-	-	-	-
Long-term debt (including interest payments)	9,270	(913)	(1,736)	(593)	(882)	(605)	(10,072)
	10,168	(1,703)	(1,820)	(603)	(886)	(606)	(10,083)
Derivative Financial Liabilities							
Interest rate swaps used for hedging	40	-	(8)	(12)	(9)	(8)	(4)
Cross currency swaps used for hedging	48						
Cash outflow		-	(6)	(3)	(5)	(6)	(293)
Cash inflow		-	5	4	6	6	248
Forward foreign exchange contracts used for hedging	(54)						
Cash outflow		(28)	(101)	-	-	-	(923)
Cash inflow		33	113	-	-	-	947
Other forward foreign exchange contracts designated at fair value	1						
Cash outflow		(16)	(18)	-	-	-	-
Cash inflow		16	18	-	-	-	-
Commodity derivative liabilities designated at fair value	770	(200)	(447)	(105)	(16)	(5)	-
	805	(195)	(444)	(116)	(24)	(13)	(25)
Total	10,973	(1,898)	(2,264)	(719)	(910)	(619)	(10,108)
Commodity derivative assets designated at fair value	(741)	182	443	102	32	5	-
Net Total[1]	$10,232	$(1,716)	$(1,821)	$(617)	$(878)	$(614)	$(10,108)

[1] BC Hydro believes that the liquidity risk associated with derivative financial liabilities needs to be considered in conjunction with the profile of payments or receipts arising from derivative financial assets. It should be noted that cash flows associated with future energy sales and commodity contracts which are not considered financial instruments under HB 3855 are not included in this analysis, which is prepared in accordance with HB 3862.

Market Risks

(a) Currency Risk

Sensitivity Analysis

A $0.01 strengthening of the US dollar against the Canadian dollar at December 31, 2008 would have no material impact on net income and would have decreased other comprehensive income by $1 million. This analysis assumes that all other variables, in particular interest rates, remain constant. A $0.01 weakening of the U.S. dollar against the Canadian dollar at December 31, 2008 would have had an equal but opposite effect on net income and other comprehensive income.

This sensitivity analysis has been determined assuming that the change in foreign exchange rates had occurred at December 31, 2008 and had been applied to each of BC Hydro's exposure to currency risk for both derivative and non-derivative financial instruments in existence at that date, and that all other variables remain constant. The stated change represents management's assessment of reasonably possible changes in foreign exchange rates over the period until the next quarter end balance sheet date.

For US dollar derivative financial instruments, a $0.01 strengthening or weakening of the U.S. dollar against the Canadian dollar at December 31, 2008 would have no significant impact on net income or other comprehensive income since all of BC Hydro's significant US dollar derivative financial instruments are designated in a cash flow hedging relationship.

(b) Interest Rate Risk

Fair value sensitivity analysis for fixed rate instruments

BC Hydro does not account for any fixed rate financial assets or liabilities as held-for-trading or available-for-sale. Therefore a change in interest rates at December 31, 2008 would not affect net income or other comprehensive income with respect to these fixed rate instruments.

Cash flow sensitivity analysis for variable rate non-derivative instruments

An increase of 100-basis points in interest rates at December 31, 2008 would have a nil impact on net income and would have no material impact on other comprehensive income. The nil impact on net income is due to the new regulatory account to capture variances from forecasts related to interest rate changes as described in note 5. This analysis assumes that all other variables, in particular foreign exchange rates, remain constant. A decrease of 100-basis points in interest rates at December 31, 2008 would have an equal but opposite effect on net income and other comprehensive income.

This sensitivity analysis has been determined assuming that the change in interest rates had occurred at December 31, 2008 and had been applied to each of BC Hydro's exposure to interest rate risk for both derivative and non-derivative financial instruments in existence at that date, and that all other variables remain constant. The stated change represents management's assessment of reasonably possible changes in interest rates over the period until the next quarter end balance sheet date.

Interest rate sensitivity analysis for derivative financial instruments

For interest rate derivative financial instruments, a shift of 100-basis point in the yield curves at December 31, 2008 would have no significant impact on net income since all of BC Hydro's interest rate derivative financial instruments are designated in a fair value hedging relationship.

(c) Commodity Price Risk

Sensitivity Analysis

BC Hydro's subsidiary Powerex trades and delivers energy and associated products and services throughout North America and enters into derivative contracts to manage their commodity price risks. As a result, BC Hydro has exposure to movements in certain commodity prices, including the market price of electricity and fuels used to produce electricity. BC Hydro manages these exposures through an established risk management framework that limits components of and overall market risk exposures, delegates authority to trade, pre-defines approved products and mandates regular reporting of exposures. A Risk Management Committee forms a key part of the corporate governance framework.

BC Hydro's trading activities are subject to various limits and controls, including Value at Risk in US dollars ("VaR"), Stop-Loss/Gain limits, and transaction limits. These various market risk limits are approved by the Board of Directors. A VaR measure estimates the pre-tax forward trading loss that could result from changes in the forward price curve, with a specific level of confidence, over a specific time period. Powerex uses an industry standard monte carlo VaR model, a 95 per cent confidence interval, and a 10-day holding-period.

Powerex's VaR, calculated under the methodology described above, was approximately US $10 million at December 31, 2008.

VaR as a measure of portfolio risk has several limitations. It is a lagging indicator of price risk given the recent historical volatilities in the market place and it cannot forecast unusual outlier events that may occur in the future. In addition, it is sometimes difficult to appropriately estimate the VaR associated with illiquid or non-standard products. As a result, Powerex uses additional measures to supplement the use of VaR to measure price risk. These include the use of a historic VaR methodology, weekly stress tests, notional limits for illiquid or emerging products, and independent reporting regarding non-standard options.