SECOND QUARTER REPORT FISCAL 2009

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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 six month periods ended September 30, 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 six month periods ended September 30, 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 second quarter of fiscal 2009 benefitted from increased trade income and lower finance charges, but were adversely impacted by lower domestic revenues, higher energy costs and higher operating costs 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 six month periods ended September 30, 2008 was $122 million and $210 million respectively, compared to $157 million and $162 million for the same periods in fiscal 2008.

- Hydro generation levels in the second quarter were 19 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, and system constraints arising from the GM Shrum Generating Station unit outage which occurred in March 2008 and which will not be returned to service until early in 2009. 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 our system, increasing the overall cost of energy. This was offset by reduced load.

- Results for the year reflect a positive load variance that is primarily due to reduced demand from large industrial customers as a result of weakness in the forestry sector. In the Revenue Requirements Application for Fiscal 2009 and 2010, BC Hydro has proposed that the net impact of load variance be allowed deferral treatment effective from April 1, 2008. This would eliminate the impact on net income of variability in load.

- Property, plant and equipment expenditures for the year of $637 million are 31 per cent higher than the prior year ($487 million) primarily due to the Vancouver Island Transmission Reinforcement project, generation system expansion and capacity improvements, 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.

	For the three months ended September 30			*For the six months ended September 30*		
($ in millions)	**2008**	2007	Change	**2008**	2007	Change
Income Before Regulatory Accounts	**$57**	$164	$(107)	**$66**	$297	$(231)
Net Income	**$122**	$157	$(35)	**$210**	$162	$48
Accrued Payment to the Province	**$(32)**	$128	$(160)	**$35**	$128	$(93)
Number of Domestic Customers	**N/A**	N/A	N/A	**1,782,901**	1,750,233	32,668
GWh Sold (Domestic)	**11,836**	12,781	(945)	**24,093**	25,173	(1,080)
Total Reservoir Storage (GWh)	**N/A**	N/A	N/A	**29,949**	30,776	(827)

($ in millions)	***As at September 30, 2008***	*As at March 31, 2008*	*Change*
Total Assets	**$14,274**	$13,909	$(365)
Retained Earnings	**$2,040**	$1,865	$175
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 GAAP for rate regulated enterprises but differ from enterprises that do not operate in a rate-regulated environment. These policies allow for the deferral for future recovery in rates of amounts that under GAAP would otherwise be recorded as expenses in the current accounting period. 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 September 30, 2008, income before regulatory accounts was $57 million compared to $164 million for the same period in fiscal 2008. The decrease was a result of lower domestic gross margins, arising from both lower domestic revenues and higher energy costs, and higher operating costs, 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, transfer to the Trade Income Deferral Account for the variance between plan and actual trade income, demand side management expenditures, and investigation costs related to Site C.

Net income for the second quarter was $122 million, a decrease of $35 million from fiscal 2008. The decrease in net income from the prior year was due to lower trade income, higher operating costs and finance charges, partially offset by higher domestic gross margin.

For the six months ended September 30, 2008, income before regulatory accounts was $66 million compared to $297 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, and expenditures on strategic procurement and information technology initiatives, partially offset by higher trade income and lower finance charges. Fiscal 2008 was a high water year and therefore cost of energy in that year was lower 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, transfer to the Trade Income Deferral Account for the variance between plan and actual trade income, demand side management expenditures, repair costs related to the outage at GM Shrum and investigation costs related to Site C.

Net income for the six months ended September 30, 2008 was $210 million, compared with $162 million for the same period in fiscal 2008. The increase in net income from the prior year is mainly due to higher domestic gross margin and higher trade income, offset by higher operating costs.

REVENUES

For the three months ended September 30	$ in Millions		Gigawatt hours	
	2008	2007	**2008**	2007
Domestic				
Residential	**$ 239**	$ 225	**3,346**	3,318
Light industrial and commercial	**267**	255	**4,445**	4,451
Large industrial	**128**	130	**3,718**	3,832
Other energy sales	**(11)**	57	**523**	1,181
Total Domestic	**$ 623**	$ 667	**12,032**	12,782
Trade				
Electricity	**$ 562**	$ 268	**10,312**	11,542
Gas	**303**	176	**3,816**	3,696
Total Trade	**865**	444	**14,128**	15,238
Total	**$ 1,488**	$ 1,111	**26,160**	28,020

For the six months ended September 30	$ in Millions		Gigawatt hours	
	2008	2007	**2008**	2007
Domestic				
Residential	**$ 508**	$ 478	**7,167**	7,072
Light industrial and commercial	**533**	511	**8,871**	8,936
Large industrial	**257**	260	**7,468**	7,687
Other energy sales	**38**	83	**783**	1,478
Total Domestic	**$ 1,336**	$ 1,332	**24,289**	25,173
Trade				
Electricity	**$ 863**	$ 616	**20,165**	23,327
Gas	**548**	321	**6,691**	6,026
Total Trade	**1,411**	937	**26,856**	29,353
Total	**$ 2,747**	$ 2,269	**51,145**	54,526

Total revenue for the three and six months ended September 30, 2008 was $1,488 million and $2,747 million, an increase of $377 million and $478 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 relative to the prior year as higher average customer rates in all rate classes and increased consumption in the residential sector were 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 $623 million for the second quarter were $44 million or 7 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, lower other energy sales, 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 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, an increase in the rate of customer growth, and an increase in average residential consumption due to colder temperatures compared with the same period in the prior fiscal year.

Total domestic revenues of $1,336 million for the six months ended September 30, 2008 were $4 million or 0.3 per cent higher than for the same period in the previous year. The increase was mainly due to higher average customer rates, an increase in the rate of customer growth and colder weather that contributed to the increase compared with the same period in the prior fiscal year. This was offset by a 4 per cent decrease in domestic sales volumes due to lower usage, lower consumption in commercial and wood manufacturing sectors 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.

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 second quarter ended September 30, 2008 increased due to both electricity and gas revenues. The increase in net electricity revenue is primarily a result of a $207 million decrease in forward purchases which are netted in revenue in accordance with Generally Accepted Accounting Principles and an $87 million increase in gross electricity sales. Gross electricity sales for the quarter reflect an increase in the average gross electricity sales price offset by an 11 per cent decrease in gross electricity sales volumes. The increase in the average gross electricity sales price was due largely to higher market prices in the Northwest and Southwest driven by higher gas prices in the current year. The increase in gas revenue was largely driven by a 51 per cent increase in the average gross gas sales price and a 3 per cent increase in gross gas sales volumes. The increase in the average gross gas sales price was largely attributable to increased gas market prices during much of the current year driven by increased concerns about supply and higher crude oil costs than the prior year.

Trade revenues for the six months ended September 30, 2008 increased due to both electricity and gas revenues. The increase in net electricity revenue is a result of a $267 million decrease in forward electricity purchases which are netted in revenue in accordance with GAAP, partially offset by a $20 million decrease in gross electricity sales. Gross electricity sales reflect a decrease in gross electricity sales volumes, offset by an increase in the average gross electricity sales price. The decrease in gross electricity purchase volumes is primarily due to generally less attractive purchase prices. The increase in the average gross electricity sales price is largely due to increased gas prices as described above. The increase in gas revenue reflects an increase in both the average gross gas sales price and gross gas sales volumes. The increase in the average gross gas sales price was largely due to increased concerns about supply and higher crude oil costs in the current year.

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	($ in millions)		(gigawatt hours)		($ per MWh)	
ended September 30	**2008**	2007	**2008**	2007	**2008**[2]	2007[2]
Hydroelectric (Water Rentals) per ARMC recommendation	**$ 76**	$ 76	**10,481**	12,705	**$ 7.25**	$ 5.80
Purchases from Independent Power Producers and other long-term contracts	**146**	114	**2,338**	2,038	**62.44**	55.88
Other electricity purchases - Domestic	**19**	8	**319**	174	**59.74**	48.25
Gas for thermal generation	**15**	9	**93**	120	**165.67**	76.07
Transmission charges and other expenses	**14**	27	**24**	23	**-**	-
Allocation to/from trade energy	**(23)**	(60)	**(354)**	(1,120)	**69.67**	55.69
Total Domestic	**$ 247**	$ 174	**12,901**	13,940	**$19.12**	$12.49
Other electricity purchases - Trade[1]	**$ 325**	$ 73	**9,741**	9,534	**66.90**	63.61
Remarketed gas	**308**	176	**3,912**	3,814	**78.70**	46.08
Transmission charges and other expenses	**74**	61	**-**	-	-	-
Allocation to/from domestic energy	**23**	60	**354**	1,120	**69.67**	55.69
Total Trade	**$ 730**	$ 370	**14,007**	14,468	**$75.45**	$62.44
Total Energy Costs	**$ 977**	$ 544	**26,908**	28,408	**$48.48**	$50.72

For the six months	($ in millions)		(gigawatt hours)		($ per MWh)	
ended September 30	**2008**	2007	**2008**	2007	**2008**[2]	2007[2]
Hydroelectric (Water Rentals) per ARMC recommendation	**$ 140**	$ 144	**19,787**	24,236	**$ 7.19**	5.98
Purchases from Independent Power Producers and other long-term contracts	**277**	228	**4,309**	3,765	**64.28**	60.67
Other electricity purchases - Domestic	**118**	28	**2,064**	559	**57.36**	50.09
Gas for thermal generation	**28**	22	**196**	225	**144.67**	96.55
Transmission charges and other expenses	**26**	34	**51**	49	**-**	-
Allocation to/from trade energy	**-**	(83)	**(56)**	(1,524)	**70.27**	55.94
Total Domestic	**$ 589**	$ 373	**26,351**	27,310	**$22.37**	$13.67
Other electricity purchases - Trade[1]	**$ 489**	$ 274	**19,862**	20,863	**$56.34**	$56.14
Remarketed Gas	**556**	$ 315	**6,833**	6,226	**81.42**	50.53
Transmission charges and other expenses	**158**	$ 130	**-**	-	-	-
Allocation to/from domestic energy	-	$ 82	**56**	1,524	**70.27**	55.94
Total Trade	**$1,203**	$ 801	**26,751**	28,613	**$68.14**	$59.34
Total Energy Costs	**$1,792**	$1,174	**53,102**	55,923	**$45.43**	$37.05

[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 second quarter of fiscal 2009 were $977 million, 80 per cent higher than the second quarter last year, primarily as a result of lower hydro generation which required higher purchases from IPPs and higher electricity and gas trade volumes and prices.

For the six months ended September 30, 2008, total energy costs of $1,792 million were $618 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 gas trade volumes and prices

Domestic Energy Costs

Domestic energy costs of $247 million were $73 million or 42 per cent higher than the second quarter of fiscal 2008. During the early portion of the second quarter of fiscal 2009, BC Hydro system reservoirs had an above normal risk of spill that resulted in a modest amount of surplus electricity sales, while in the latter part of the same quarter BC Hydro began purchasing market electricity again, driven by decreased inflows and economic pricing of electricity in the market. Lower hydro generation also resulted in higher purchase volumes from IPP's, including Island Cogeneration, at higher prices than in the prior year. 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 in this year.

Domestic energy costs of $589 million year to date were $216 million or 58 per cent higher than the six months ended September 30, 2007. The increase was primarily due to purchases of relatively high priced market energy due to system energy constraints, with the main contributing factor being the GM Shrum Generating Station unit outage which occurred in March 2008 and which will not be returned to service until early in 2009, while lower water inflows during the second quarter contributed to lower hydro generation and higher energy purchases, particularly from Island Cogeneration and Alcan, compared with the prior year.

Trade Energy Costs

Trade energy costs for the quarter ended September 30, 2008 increased primarily due to trade electricity and remarketed gas purchases. The increase in net trade electricity purchases includes a decrease in forward electricity purchases of $207 million, which is netted in revenue in accordance with Generally Accepted Accounting Principles (GAAP), and a $45 million increase in gross electricity purchases. Gross electricity purchases for the quarter reflect an increase in the average gross electricity purchase price and a 2 per cent increase in volumes. The increase in the average gross electricity purchase price was mainly due to higher market prices in the Northwest, driven by higher gas costs in the current year. The increase in remarketed gas costs was due to a 71 per cent increase in the average gross gas purchase price and a 3 per cent increase in gross gas purchase volumes. The increase in the average gross gas purchase price was largely attributable to increased gas market prices in the current year driven by increased concerns about supply and higher crude oil costs.

Trade energy costs for the six months ended September 30, 2008 increased primarily due to remarketed gas and trade electricity purchases. The increase in net trade electricity purchases includes a $267 million decrease in forward electricity purchases, which are netted in revenue in accordance with GAAP, partially offset by a $52 million decrease in gross trade electricity purchases. Gross electricity purchases reflect a decrease in gross electricity purchase volumes and a marginal increase in the average gross electricity purchase price. The increase in remarketed gas purchases was due to a 61 per cent increase in the average gross gas purchase price and an increase in gross gas purchase volumes. The increase in the average gross gas purchase price was largely due to increased concerns about supply and higher crude oil costs in the current year.

Water Inflows

Water inflows into BC Hydro's reservoirs were 17 per cent lower than in the second quarter of the prior year, and 9 per cent lower than average (average from 1971-2000).

The BC Hydro reservoirs have been managed such that the combined storage in BC Hydro reservoirs at September 30, 2008 was 110 per cent of average, compared to 113 per cent of average at September 30, 2007 (average storage levels relate to the average from 1985-2007), with the Williston reservoir on the Peace River system at 110 per cent of average (fiscal 2008 – 113 per cent), and the Kinbasket reservoir on the Columbia River system at 112 per cent of average (fiscal 2008 – 113 per cent).

Operating Costs

Operations costs for the three and six months ended September 30, 2008 were $22 million and $39 million higher than in the same period last year, primarily due to higher demand side management (DSM) costs and expenditures on the smart metering and infrastructure project (SMI) which supports energy conservation. Both of these costs are transferred to regulatory accounts and do not impact current year net income.

Maintenance costs for the three and six months ended September 30, 2008 were $7 million and $33 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 increased routine vegetation work to improve system resiliency for the storm season.

Administration costs for the three and six months ended September 30, 2008 were $16 million and $15 million higher than in the same period in the prior year. The increase is primarily the result of expenditures on strategic procurement and information technology initiatives.

Amortization Expense

Amortization expense of $99 million for the second quarter was $8 million higher than the same period in the previous year due to increased assets in service and a one time write off of unrecoverable costs associated with damaged equipment, partially offset by lower dismantling costs.

Amortization expense of $192 million for the six months ended September 30, 2008 was $10 million higher than for the same period in the previous year due to increased assets in service, and a one time write off of unrecoverable costs associated with damaged equipment, partially offset by lower dismantling costs, and a gain on the sale of land.

Finance Charges

Finance charges of $113 million for the second quarter were $7 million lower than the same period in the prior year due to lower short term interest rates and higher capitalized interest. These positive variances were partially offset by translation losses due to the weakening of the Canadian dollar as compared to the US dollar and lower sinking fund income due to the liquidation of the Canadian sinking funds in June 2008.

Finance charges of $220 million for the six months ended September 30, 2008, were $12 million lower than for the same period in the previous year. The decrease is due to lower short term interest rates and higher capitalized interest. The positive variances were partially offset by a negative foreign exchange variance due to foreign exchange translation losses on net unhedged US dollar denominated debt as a result of the strengthening of the Canadian dollar as compare to the US dollar in fiscal 2008 as compared to 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.

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.

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 Generally Accepted Accounting Principles (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 BC Utilities Commission 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 September 30, 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 has been named, along with other energy providers, in a number of lawsuits and US 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. Although a number of lawsuits have been dismissed, certain significant proceedings remain active, including an action commenced by the California Department of Water Resources (CDWR) in which it claims 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 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 practices or concerted partnership 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 has not issued a final order in that settlement. However, FERC has already decided that refunds will have to be paid by energy providers to various California parties in respect of the period from October to December 2000, but the precise amount has not been determined and the timing of the refunds is unknown. It is also possible that refunds will be ordered for other periods in the California crisis.

At September 30, 2008, Powerex was owed US$268 million (CDN$284 million) by the markets operated by the California Power Exchange (Cal Px) and the California Independent System Operator (CISO) 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 CISO 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 approval of the British Columbia Utilities Commission (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 six months ended September 30, 2008, BC Hydro transferred, on a net basis, $65 million and $144 million, respectively, to regulatory accounts, compared with $7 million and $135 million transferred from 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 September 30, 2008, was $716 million compared to $293 million at September 30, 2007.

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 slightly lower inflows experienced in the current year (105 per cent above average), hydro generation was lower than forecast by 1,841 GWh resulting in higher market purchases required for domestic consumption. The average cost of hydro generation is $7.19 per MWh compared to the average cost of $57.36 per MWh for market purchases for the six month period ended September 30, 2008.

Revenue Requirements Filing

BC Hydro filed its Revenue Requirements Application (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.

Any requested rate increase requires 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 between October 6 and 29, 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. In the October 17 update, BC Hydro also proposed regulatory accounts for 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 and a reduction in the rate rider in fiscal 2010 from 0.5 per cent to 0 per cent. BC Hydro expects a decision on the RRA in early 2009.

Rate Design

BC Hydro filed a Residential Inclining Block Rate (RIB) application on February 26, 2008. It proposed a two-step rate, with the Step-2 rate price applicable to all energy consumption over 1,600 kWh per bi-monthly billing period. While the rate is designed to be revenue neutral to the residential rate class, individual customers will see bill impacts, which can be mitigated through consumption behaviour changes and participation in BC Hydro's Power Smart programs. BC Hydro completed an oral hearing on this application before the BCUC in June, and received a commission order on August 28, 2008. The BCUC approved a two-step RIB rate to be introduced on October 1, 2008. The rate design differed from that proposed by BC Hydro, with the Step-2 rate to be applied to consumption over 1,350 kWh.

BC Hydro also file a Transmission Service Rate Re-Pricing (TSR) application in February 2008, proposing to increase the Tier 2 rate for industrial customers from 5.40 cents/kWh to 7.36 cents/kWh to reflect more recent information on BC Hydro's long-term opportunity cost of new supply. The BCUC approved the new Tier 2 rate effective April 1, 2008. The TSR Tier 1 rate was approved on an interim basis until a final decision is issued by the BCUC regarding BC Hydro's F09/F10 Revenue Requirements Application.

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.

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 January 2009, with a final BCUC decision expected in the late spring of 2009.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow used by operating activities for the second quarter was $76 million, compared with $103 million provided by operating activities for the same period last year. The decrease was primarily due to an increase in market energy purchases relative to the prior year and an increase in unrealized gains on mark-to-market. For the six months ended September 30, 2008, cash flow provided by operating activities was $64 million, compared with $297 million for the same period last year, with the decrease due to increased market energy purchases and changes in working capital, partially offset by a decrease in unrealized gains on mark-to-market and foreign exchange translation losses.

PROPERTY, PLANT AND EQUIPMENT EXPENDITURES

Property, plant and equipment expenditures were as follows:

	For the three months ended September 30[1]		*For the six months ended September 30*[1]	
(in millions)	**2008**	2007	**2008**	2007
Distribution improvements and expansion	**$ 103**	$ 82	**$ 195**	$ 165
Generation replacements and expansion	**96**	77	**173**	137
Transmission lines and substation replacements & expansion	**118**	76	**227**	141
General, including computers and vehicles	**25**	30	**42**	44
	$ 342	$ 265	**$ 637**	$ 487

[1] Excludes Intangible assets

The increase in distribution improvements and expansion capital expenditures for the three and six month period ended September 30, 2008 is primarily due to system resiliency work and increased system improvement expenditures. Both the quarter and year to date expenditures for generation replacements and expansion expenditures increased mainly as a result of increased spending on the Revelstoke Unit 5 installation and the Aberfeldie Redevelopment. These increases are partially offset by lower spending on the Coquitlam Dam Seismic Improvement project and the John Hart 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 the Interior to Lower Mainland Transmission project while the year's activity also includes Kinder Morgan TMX1 and various IPP related projects. On a year to date basis, these increases are partially offset by lower expenditures on the Terasen TMPSE project, the Gibraltar Mine Load Increase and the MCA-GIS Breaker Replacement project.

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.

BC Hydro electricity generating facilities continue to have high reservoir levels, providing BC Hydro with increased operating flexibility and allowing them to better mitigate the impacts of potentially volatile market energy prices for the remainder of fiscal 2009. However, despite the higher reservoir levels, additional electricity supplies will continue to be required to meet peak demand periods that typically occur during the coldest winter days in November through February.

Driven largely by a downturn in the forestry 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. The return on pension fund assets has a significant impact on non-current employee future benefit costs. Based on the recent market volatility, market returns on the pension plan assets are expected to be significantly lower than originally forecast. The total impact on costs has not been determined but could be significant.

BC Hydro is also exposed to financial risk, such as changes in interest rates or foreign exchange rates. Towards the end of the second quarter, interest rates began to fall in response to the global financial turmoil allowing BC Hydro an opportunity to reduce floating interest rate risk. 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'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 assumes 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.

As part of its revenue requirements process, BC Hydro filed an updated with the BCUC on October 17, 2008. The significant changes from the Service Plan for fiscal 2009 include:

- A decrease in customer load of 2,089 GWh for total customer load of 52,702 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 2.92 per cent.
- A $55 million increase in trade income resulting from short-term market opportunities experienced earlier in the year.

As a result of the above changes, BC Hydro's forecast rate increases have changed from 6.56 per cent and 8.21 per cent for fiscal 2009 and fiscal 2010 respectively in the Service Plan to 3.75 per cent and 10.17 per cent for fiscal 2009 and fiscal 2010 respectively in the Q2 forecast. The cumulative rate increase over the two year period has been reduced from 15.30 per cent in the Service Plan to 14.30 per cent in the current forecast.

On November 21, 2008, BC Hydro filed its Final Argument in respect of the RRA, which proposes that the approved interim rate increase for fiscal 2009 of 6.56 per cent remain in place, with the additional revenue (surplus to the 3.75 per cent increase) being transferred to the deferral account balances (effectively reducing those balances). This has the consequential impact of lowering the fiscal 2010 increase to 7.5 per cent and reducing the deferral account rate rider in fiscal 2010 from 0.5 per cent to 0 per cent. The BCUC may however determine that the difference between the final rate increase for fiscal 2009 and the interim rate increase be refunded to customers.

A decision from the BCUC on BC Hydro's proposed rate increase is pending and is expected in early 2009.

FINANCIAL STATEMENTS

CONSOLIDATED STATEMENT OF OPERATIONS

(Unaudited)	*For the three months ended September 30*		*For the six months ended September 30*	
(in millions)	**2008**	2007	**2008**	2007
Revenues				
Domestic	**$ 623**	$ 667	**$1,336**	$ 1,332
Trade	**865**	444	**1,411**	937
	1,488	1,111	**2,747**	2,269
Expenses				
Energy Costs:				
Domestic	**247**	174	**589**	373
Trade	**730**	369	**1,203**	801
Operations	**83**	61	**163**	124
Maintenance	**85**	78	**171**	138
Administration	**32**	16	**60**	45
Taxes	**42**	38	**83**	77
Amortization	**99**	91	**192**	182
	1,318	827	**2,461**	1,740
Operating Income	**170**	284	**286**	529
Finance Charges	**(113)**	(120)	**(220)**	(232)
Income Before Regulatory Accounts	**57**	164	**66**	297
Net Change in Regulatory Accounts (note 5)	**65**	(7)	**144**	(135)
Net Income	**$ 122**	$ 157	**$ 210**	$ 162

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(Unaudited)	*For the three months ended September 30*		*For the six months ended September 30*	
(in millions)	**2008**	2007	**2008**	2007
Net Income	**$ 122**	$ 157	**$ 210**	$ 162
Other Comprehensive Income (note 8)	**23**	39	**(5)**	66
Comprehensive Income	**$ 145**	$ 196	**$ 205**	$ 228

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

(Unaudited)	*For the six months ended September 30*	
(in millions)	**2008**	2007
Retained Earnings, Beginning of Period	**$1,865**	$ 1,784
Net Income	**210**	162
Accrued Payment to the Province	**(35)**	(128)
Retained Earnings, End of Period	**$2,040**	$ 1,818

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED BALANCE SHEET

(Unaudited) *(in millions)*	***As at September 30 2008***	*As at March 31 2008*
ASSETS		
Property, Plant and Equipment, net	**$ 11,203**	$ 10,746
Current Assets		
Cash and cash equivalents	**26**	22
Current portion of sinking funds	**1**	506
Accounts receivable and accrued revenue	**494**	538
Inventories (note 3)	**162**	83
Prepaid expenses	**186**	99
Current portion of derivative financial instrument assets	**96**	60
	965	1,308
Other Assets and Deferred Charges		
Intangible assets	**407**	411
Sinking funds	**93**	89
Employee future benefits	**313**	299
Regulatory assets (note 5)	**1,164**	929
Derivative financial instrument assets	**129**	127
	2,106	1,855
	$ 14,274	$ 13,909
LIABILITIES AND EQUITY		
Long-term debt net of sinking funds	**$ 6,767**	$ 6,957
Sinking funds presented as assets	**93**	89
Long-Term Debt	**6,860**	7,046
Current Liabilities		
Current portion of long-term debt, net of short-term sinking fund	**1,621**	584
Current portion of sinking funds presented as assets	**1**	506
Current portion of Long-Term Debt	**1,622**	1,090
Accounts payable and accrued liabilities	**948**	1,281
Current portion of derivative financial instrument liabilities	**116**	76
	1,064	1,357
Other Liabilities		
Regulatory liabilities (note 5)	**448**	361
Deferred contributions	**1,020**	982
Derivative financial instrument liabilities, long-term	**185**	192
Other long-term liabilities	**984**	960
	2,637	2,495
Shareholder's Equity		
Retained Earnings	**2,040**	1,865
Accumulated other comprehensive income (note 8)	**51**	56
	2,091	1,921
	$ 14,274	$ 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 September 30*		*For the six months ended September 30*	
(in millions)	**2008**	2007	**2008**	2007
Operating Activities				
Net income	**$ 122**	$ 157	**$ 210**	$ 162
Regulatory account transfers	**(78)**	(11)	**(162)**	99
Adjustments for non-cash items:				
Amortization of regulatory accounts	**19**	19	**29**	40
Amortization expense	**99**	91	**192**	182
Foreign exchange translation (gains) losses	**6**	(10)	**5**	(22)
Unrealized (gains) losses on mark-to-market	**(77)**	1	**5**	(19)
Other non-cash items	**(10)**	(2)	**(14)**	(2)
	81	245	**265**	440
Working capital changes	**(157)**	(142)	**(201)**	(143)
Cash provided by (used in) operating activities	**(76)**	103	**64**	297
Investing Activities				
Property, plant and equipment and intangible asset expenditures	**(345)**	(267)	**(652)**	(497)
Deferred contributions	**28**	27	**55**	50
Other items	**(1)**	(3)	**(7)**	(8)
Cash used in investing activities	**(318)**	(243)	**(604)**	(455)
Financing Activities				
Bonds				
Issued	**-**	-	**202**	830
Retired	**(18)**	(9)	**(94)**	(542)
Revolving borrowings	**269**	28	**201**	153
Sinking fund withdrawals	**-**	4	**508**	143
Settlement of derivative instruments	**15**	(2)	**15**	(94)
Payment to the Province	**-**	-	**(288)**	(331)
Cash provided by financing activities	**266**	21	**544**	159
Increase (decrease) in cash and cash equivalents	**(128)**	(119)	**4**	1
Cash and cash equivalents, beginning of period	**154**	128	**22**	8
Cash and Cash Equivalents, End of Period	**$ 26**	$ 9	**$ 26**	$ 9
Supplemental Disclosure of Cash Flow Information				
Interest paid	**$ 111**	$ 120	**$ 250**	$ 252

See accompanying notes to the interim consolidated financial statements.

NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED) SEPTEMBER 30, 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.

NOTE 3: INVENTORIES

(in millions)	***As at September 30 2008***	*As at March 31 2008*
Materials and supplies	**$ 71**	$ 69
Natural gas trading inventories	**91**	14
	$162	$ 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 September 30, 2008 there were no write downs recorded to reduce certain inventory items to their net realizable value. Due to significant decreases in forward gas prices during the second quarter, natural gas trading inventories were written down to net realizable value in the 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.

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's Revenue Requirements Application (RRA) for fiscal 2009 and 2010 was filed with the BCUC on February 20, 2008 and a decision is expected in early 2009. 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.

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.

Regulatory Accounts

The following regulatory assets and liabilities have been established through rate regulation. For the three and six months ended September 30, 2008, the impact of regulatory accounting has resulted in an increase to net income of $65 million and $144 million respectively (three and six months ended September 30, 2007 – $7 million and $135 million decrease respectively).

(in millions)	*April 1, 2008*	*Adjustments*	*Addition (Reduction)*	*Amortization*	*Net Change*	*Sept. 30, 2008*
Regulatory Assets						
Heritage Deferral Account	$ 78	$ -	$ 123	$ (11)	$ 112	$ 190
Non-Heritage Deferral Account	52	-	71	(7)	64	116
BCTC Deferral Account	21	-	(7)	(3)	(10)	11
Demand-Side Management Programs	309	-	38	(21)	17	326
First Nation Negotiations, Litigation and Settlement Costs	356	4	12	(3)	9	369
Other Regulatory Accounts	113	-	35	4	39	152
Total Regulatory Assets	$ 929	$ 4	$ 272	$ (41)	$ 231	$1,164
Regulatory Liabilities						
Future Removal and Site Restoration Costs	$ 192	$ -	$ -	$ (8)	$ (8)	$ 184
Trade Income Deferral	103	-	104	(14)	90	193
Foreign Exchange Gains and Losses	66	-	(5)	10	5	71
Total Regulatory Liabilities	$ 361	$ -	$ 99	$ (12)	$ 87	$ 448
Net	$ 568	$ 4	$ 173	$ (29)	$ 144	$ 716

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. BC Hydro also intends to seek approval to defer all fiscal 2009 costs of the Smart Metering Infrastructure project. The balance related to these proposed and potential regulatory accounts, included in Other Regulatory Accounts, is $30 million as at September 30, 2008.

On October 17, 2008, BC Hydro filed an update to its RRA to reflect an increase in the trade income forecast, lower domestic demand and resulting lower energy costs, and lower short-term interest rates. The update also proposed the establishment of two new regulatory accounts to capture variances from forecast relating to interest rate changes and to non-current employee future benefits costs. 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 early 2009.

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 September 30, 2008 and March 31, 2008 was as follows:

(in millions)	***As at September 30 2008***	*As at March 31 2008*
Long-term debt, net of sinking funds	**$7,191**	$6,545
Interest-bearing borrowings	**1,197**	996
Less: cash and cash equivalents	**(26)**	(22)
Net Debt	**$8,362**	$7,519
Retained earnings	**2,040**	1,865
Accumulated other comprehensive income	**51**	56
Deferred revenue	**-**	353
Contributions from the Columbia River Treaty	**-**	157
Contributions in aid of construction	**-**	825
Total Equity	**$2,091**	$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 September 30 is below 85 per cent due to the 80:20 cap.

NOTE 7: EMPLOYEE FUTURE BENEFITS

BC Hydro's cost for employee future benefits for the three and six months ended September 30, 2008 was $9 million and $18 million respectively (2007 – $11 million and $22 million).

NOTE 8: OTHER COMPREHENSIVE INCOME AND ACCUMULATED OTHER COMPREHENSIVE INCOME

Other Comprehensive Income

(in millions)	*For the three months ended September 30* **2008**	2007	*For the six months ended September 30* **2008**	2007
Other Comprehensive Income				
Unrealized gain (loss) on sinking fund balances	**$ -**	$ 3	**$ -**	$(10)
Reclassification to income of loss on sinking funds	-	3	-	5
Unrealized gain (loss) on derivatives designated as cash flow hedges	**65**	(24)	**30**	(98)
Reclassification to income of loss on derivatives designated as cash flow hedges	**(42)**	57	**(35)**	169
Other Comprehensive Income	**$ 23**	$ 39	**$ (5)**	$ 66

Accumulated Other Comprehensive Income

(in millions)	*For the six months ended September 30* **2008**	2007
Accumulated other comprehensive income, beginning of period	**$ 56**	$ (20)
Other comprehensive income for the period	**(5)**	66
Accumulated Other Comprehensive Income, End of Period	**$ 51**	$ 46

NOTE 9: COMMITMENTS AND CONTINGENCIES

Legal Proceedings

Since 2000, Powerex has been named, along with other energy providers, in a number of lawsuits and US 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. Although a number of lawsuits have been dismissed, certain significant proceedings remain active, including an action commenced by the California Department of Water Resources (CDWR) in which it claims 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 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 practices or concerted partnership 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 has not issued a final order in that settlement. However, FERC has already decided that refunds will have to be paid by energy providers to various California parties in respect of the period from October to December 2000, but the precise amount has not been determined and the timing of the refunds is unknown. It is also possible that refunds will be ordered for other periods in the California crisis.

At September 30, 2008, Powerex was owed US$268 million (CDN$284 million) by the markets operated by the California Power Exchange (Cal Px) and the California Independent System Operator (CISO) 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 CISO 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 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 is limited to the carrying amount presented as assets 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 CDN/US dollar exchange rate. In addition, all commodity derivatives and contracts priced in US dollars are also affected by the CDN/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 September 30, 2008:

	As at September 30, 2008		*Interest Income recognized into income (Expense)*	
(in millions)	Carrying Value	Fair Value	For the three months ended September 30	For the six months ended September 30
Held for Trading:				
Cash and cash equivalents	$ 26	$ 26	$ -	$ 1
Revolving borrowings – Cdn	(1,197)	(1,197)	(7)	(13)
Receivables:				
Accounts receivable and accrued revenues	$ 494	$ 494	$ -	$ -
Available for Sale:				
Sinking funds – US	$ 2	2	$ -	$ -
Held to Maturity:				
Sinking funds – US	$ 92	$ 98	$ 1	$ 2
Other Financial Liabilities:				
Accounts payable and accrued liabilities	$ (948)	$ (948)	$ -	$ -
Long-term debt (including current portion due in one year)	(7,285)	(8,274)	(118)	(237)

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:

(in millions)	**As at September 30, 2008** 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)	$ (116)	$ (116)
Interest rate swaps (fair value hedges for debt)	50	50
Non-Designated Hedges		
Foreign currency contracts	$ 1	$ 1
Commodity derivatives	(10)	(10)
Embedded derivatives	(1)	(1)

As at September 30, 2008 there were no non-designated interest rate swaps.

For the three and six months ended September 30, 2008, a gain of $1 million and a loss of $1 million 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 six months ended September 30, 2008, a gain of $65 million and a gain of $30 million respectively was recognized in other comprehensive income and $42 million and $35 million respectively was removed from other comprehensive income and reported in net income, offsetting foreign exchange gains recorded during the first quarter and foreign exchange losses recorded in the second quarter.

For derivatives not designated as hedging instruments, no amount was recognized in domestic revenue for the three and six months ended September 30, 2008. A gain of $2 million and a gain of $1 million respectively was recognized in finance charges for the three and six months ended September 30, 2008. A gain of $118 million and a gain of $51 million respectively was recorded in trade revenue for the three and six months ended September 30, 2008.

(in millions)	***As at September 30 2008***
Derivatives Represented by:	
Derivatives designated as hedges	$ (66)
Derivatives not designated as hedges	$ (10)
	$ (76)

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 September 30, 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

(in millions)	***As at September 30 2008***
Current	$ 329
Past due (30-59 days)	12
Past due (60-89 days)	3
Past due (more than 90 days)	4
	348
Allowance for doubtful accounts	(6)
	$ 342

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 this fiscal year.

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 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	19	4	100
Derivative financial instrument assets	65	34	1	100

The outstanding amount of collateral received from customers at September 30, 2008 was $11 million.

LIQUIDITY RISK

The following table details remaining contractual maturities at the balance sheet date 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 the balance sheet date. In respect of the cash flows in U.S. dollars, the exchange rate as at the balance sheet date has been used.

(in millions)	*Carrying Value*	*Fiscal 2009 (6 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)	$ 788	$ (719)	$ (44)	$ (9)	$ (9)	$ -	$ (7)
Bank overdrafts	4	(4)	-	-	-	-	-
Payment to the Province	35	-	(35)	-	-	-	-
Long-term debt (including interest payments)	8,603	(1,344)	(1,179)	(581)	(871)	(593)	(9,715)
		(2,067)	(1,258)	(590)	(880)	(593)	(9,722)
Derivative Financial Liabilities							
Interest rate swaps used for hedging	15	(2)	(3)	(6)	(3)	(2)	(1)
Cross currency swaps used for hedging	78						
Cash outflow		(5)	(11)	(11)	(13)	(13)	(297)
Cash inflow		3	8	7	10	10	217
Forward foreign exchange contracts used for hedging	25						
Cash outflow		(28)	(101)	-	-	-	(923)
Cash inflow		29	98	-	-	-	819
Other forward foreign exchange contracts designated at fair value	-						
Cash outflow		(24)	(16)	-	-	-	-
Cash inflow		24	16	-	-	-	-
Commodity derivative liabilities designated at fair value	485	(235)	(175)	(53)	(11)	(4)	-
		(238)	(184)	(63)	(17)	(9)	(185)
Total		(2,305)	(1,442)	(653)	(897)	(602)	(9,907)
Commodity derivative assets designated at fair value	(475)	237	177	50	21	4	-
Net Total[1]		$ (2,068)	$ (1,265)	$ (603)	$ (876)	$ (598)	$ (9,907)

[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.

Market Risks

(a) Currency Risk

Sensitivity Analysis

A $0.01 strengthening of the Canadian dollar against the US dollar at the balance sheet date would have increased net income by $1 million and 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 Canadian dollar against the US dollar at the balance sheet date 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 the balance sheet date 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 Canadian dollar against the US dollar at the balance sheet date 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 the balance sheet date 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

A change of 100-basis points in interest rates at the balance sheet date would have increased (decreased) net income by $16 million and would have no material impact on other comprehensive income. This analysis assumes that all other variables, in particular foreign exchange rates, remain constant.

This sensitivity analysis has been determined assuming that the change in interest rates had occurred at the balance sheet date 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 the balance sheet date 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 ("VaR"), Stop-Loss/Gain limits, and transaction limits. These various market risk limits are approved by the Board of Directors. Included is a total VaR (in US dollars). 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 $11 million at September 30, 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.