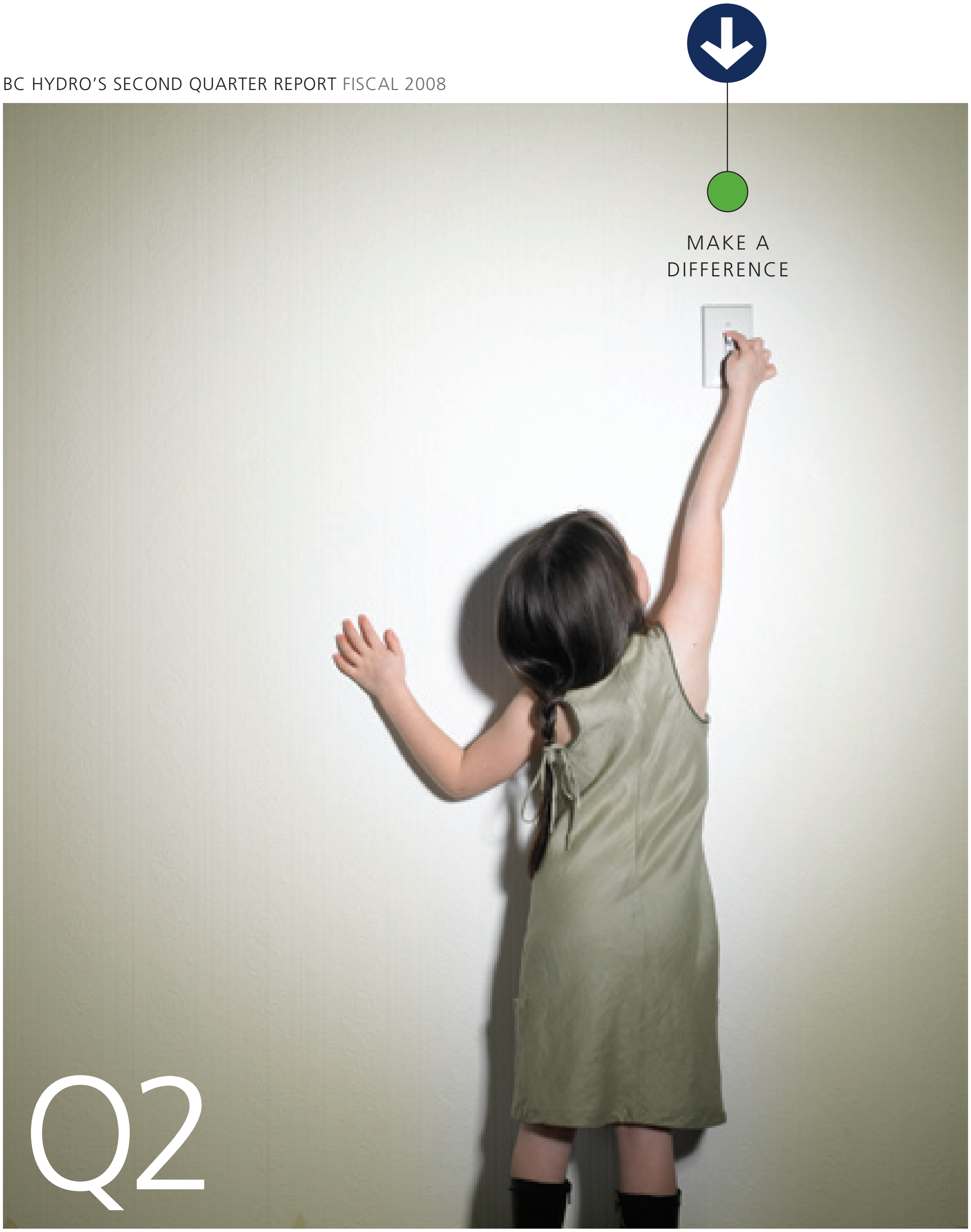
BC HYDRO'S SECOND QUARTER REPORT FISCAL 2008



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MANAGEMENT DISCUSSION AND ANALYSIS

The Management Discussion and Analysis reports on BC Hydro's consolidated results and financial position for the three and six months ended September 30, 2007 (fiscal 2008). This section should be read in conjunction with the Management Discussion and Analysis presented in the 2007 Annual Report, 2007 Annual Consolidated Financial Statements of BC Hydro, and the interim consolidated financial statements of BC Hydro for the three and six months ended September 30, 2007 and 2006. 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 2008 benefited from water inflows being 114 per cent of average for the period resulting in higher hydro generation, reducing the required energy purchases and reducing the total cost of energy compared to the prior year. Differences to planned amounts are deferred for the benefit of customers.

Highlights

- Net income for the three and six months ended September 30, 2007 was $157 million and $162 million respectively, compared with $204 million for the same periods in fiscal 2007.
- For the six months ended September 30, 2007, BC Hydro experienced higher than average system inflows (114 per cent of average), resulting in a 30 per cent increase in hydro generation over the prior year. BC Hydro and its customers benefited from this increase by reducing the volume of energy purchased to meet domestic requirements, lowering the overall cost of energy.
- BC Hydro filed a new Alcan Electricity Purchase Agreement with the BCUC on September 5, 2007. The new agreement addresses the concerns previously expressed by the BCUC by providing lower prices, extended terms and an increase in capacity and scheduling services.
- The BCUC issued a preliminary decision on some aspects of the Rate Design Application filed by BC Hydro in late fiscal 2007 on September 19, 2007. The BCUC's decision requires a change to some of the assumptions contained in BC Hydro's cost of service model and a rebalancing of the rates over three years so that revenues from each customer class exactly match costs incurred to serve them.
- Property, plant and equipment expenditures of $480 million are 37 per cent higher than the prior year ($350 million) primarily due to capacity and system improvements on generation assets, seismic upgrades, stator replacements and replacement and reinforcement work underway on the Vancouver Island transmission connection.

	For the three months ended September 30			**For the six months ended September 30**		
(in millions)	2007	2006	Change	2007	2006	Change
Income Before Regulatory Accounts	$ 164	$ 57	$ 107	$ 297	$ 162	$ 135
Net Income	$ 157	$ 204	$ (47)	$ 162	$ 204	$ (42)
Accrued Payment to the Province	$ 128	$ 167	$ (39)	$ 128	$ 167	$ (39)
Number of Domestic Customers	–	–	–	1,750,233	1,721,322	28,911
GWh Sold (Domestic)	12,782	12,032	750	25,173	24,223	950
Total Reservoir Storage (GWh)	–	–	–	30,777	29,478	1,299

(in millions)	**September 30 2007**	**March 31 2007**	**Change**
Total Assets	$ 12,897	$ 12,861	$ (36)
Retained Earnings	$ 1,864	$ 1,783	$ 81
Debt to Equity[1]	70:30	70:30	–

[1] *Based on equity as defined for regulatory purposes*

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Consolidated Results of Operations

For the quarter ended September 30, 2007, income before regulatory account transfers was $164 million compared with $57 million for the same period in fiscal 2007. The increase was a result of higher domestic gross margin arising primarily from lower energy costs, offset by lower trade gross margin, higher operating costs, higher amortization expense, and higher finance charges.

For the six months ended September 30, 2007, income before regulatory account transfers was $297 million compared with $162 million for the same period in fiscal 2007. The increase was a result of higher domestic gross margin primarily from lower energy costs and lower amortization expense as the prior year included a one time $24 million adjustment to depreciation expense to revise certain asset service lives, partially offset by lower trade gross margin and higher finance charges.

Net income for the quarter ended September 30, 2007 was $157 million compared with $204 million in fiscal 2007. Net income is lower than income before regulatory accounts mainly due to the benefit of reduced market energy purchases being deferred and offset against high energy costs in the prior years. The reduction in net income from the prior year is mainly due to lower trade gross margin and higher amortization expense.

Net income for the six months ended September 30, 2007 was $162 million, compared with $204 million for the same period in fiscal 2007. Net income is lower before regulatory accounts for the same factors as shown for the quarter. The decrease in net income from the prior year is mainly due to lower trade gross margin and higher taxes.

Revenues

For the three months ended September 30	*(in millions)*		*(gigawatt hours)*	
	2007	2006	2007	2006
Domestic				
Residential	$ 225	$ 223	3,318	3,246
Light industrial and commercial	255	254	4,451	4,420
Large industrial	130	137	3,832	3,992
Other energy sales	57	13	1,181	374
Total Domestic	667	$ 627	12,782	12,032
Trade				
Electricity	$ 268	$ 219	11,542	8,864
Gas	176	116	3,696	1,840
Total Trade	$ 444	$ 335	15,238	10,704
Total	$ 1,111	$ 962	28,020	22,736

For the six months ended September 30	*(in millions)*		*(gigawatt hours)*	
	2007	2006	2007	2006
Domestic				
Residential	$ 478	$ 449	7,072	6,743
Light industrial and commercial	511	498	8,936	8,828
Large industrial	260	268	7,687	7,979
Other energy sales	83	27	1,478	673
Total Domestic	$ 1,332	$ 1,242	25,173	24,223
Trade				
Electricity	$ 616	$ 475	23,327	19,830
Gas	321	234	6,026	4,046
Total Trade	$ 937	$ 709	29,353	23,876
Total	$ 2,269	$ 1,951	54,526	48,099

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Total revenue for the three and six months ended September 30, 2007 was $1,111 million and $2,269 million, an increase of $149 million and $318 million, respectively, over the same period last year. Domestic revenues increased overall due to increased consumption driven primarily by customer growth in the residential and light industrial and commercial sectors, offset by lower revenues from large industrial customers due to the coastal forestry strike. Trade revenues were higher as a result of higher trade volumes, partially offset by lower average commodity prices.

Domestic Revenues

Total domestic revenues of $667 million for the second quarter were $40 million or six per cent higher than for the same period in the previous year. Total sales volumes increased by six per cent as a result of 28,911 new customers (11 large industrial) added to the system, and an increase in average consumption in the residential and light industrial and commercial sectors due to colder weather. This was partially offset by lower consumption in the pulp and paper industry due to the coastal forestry strike.

Total domestic revenues of $1,332 million for the six months ended September 30, 2007 were $90 million or seven per cent higher than for the same period in the previous year. Total domestic sales volumes increased by four per cent as a result of increased average consumption in the residential and light industrial and commercial sectors due to customer growth and colder weather as well as higher average customer rates. This was offset by a decline in large industrial revenue resulting from lower consumption in the pulp and paper industry due to the coastal forestry strike.

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.

Total trade revenues for the second quarter were $444 million, an increase of 33 per cent compared with $335 million in the prior year. Trade sales volumes of 15,238 GWh increased by 42 per cent from 10,704 GWh in the second quarter of the prior year as a result of increases in electricity and gas trading activities. The volume of electricity traded during the quarter was 11,542 GWh compared with 8,864 GWh in the second quarter of fiscal 2007 and average sales prices for electricity were eight per cent lower at a gross price of $72/MWh (F2007 - $78/MWh). The volume of gas sales increased to 3,696 GWh during the second quarter from 1,840 GWh in the same quarter of the prior year, with the average sales price 19 per cent lower, at a gross price of $47/MWh (F2007 - $58/MWh).

Electricity market prices in the second quarter of fiscal 2008 averaged slightly lower compared with the same period last year as a result of relatively moderate weather in the current quarter. In addition, electricity market prices in the Western United States were lower in the second quarter of fiscal 2008 compared with the same period in the prior year as there was a significant increase in demand in California in July of the prior year as a result of increased temperatures, which drove market prices higher. Although the average gas market prices in the second quarter of fiscal 2008 was similar to the same period in the prior year, the average trade sales prices realized was lower in comparison as the prior year had more volatility in prices, providing increased opportunity to sell during periods of higher prices.

Trade revenues for the six months ended September 30, 2007 were $937 million compared with $709 million in the same period last year. There was a 23 per cent increase in total gas and electricity sales volumes and a five per cent increase in average electricity sales prices to $65/MWh (F2007 - $62/MWh), which was partially offset by a five per cent decrease in average gas sales prices at $52/MWh (F2007 - $55/MWh).

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 September 30	*(in millions)*		*(gigawatt hours)*		*($ per MWh)*	
	2007	2006	2007	2006	2007	2006
Hydro generation	$ 76	$ 57	12,705	9,681	$ 5.80	$ 5.94
Purchases from Independent Power Producers and other long-term contracts	114	100	2,038	1,652	55.88	60.69
Domestic electricity purchases	8	72	174	1,330	48.25	53.88
Gas for thermal generation	9	26	120	449	76.07	57.99
Transmission charges and other expenses	27	12	23	22	–	–
Allocation to trade energy	(60)	17	(1,120)	40	55.69	63.93
Total Domestic	$ 174	$ 284	13,940	13,174	$ 12.49	$ 21.55
Other electricity purchases – trade	$ 73	$ 86	9,534	8,815	$ 63.61	$ 61.65
Remarketed gas	176	103	3,814	1,972	46.08	52.39
Transmission charges and other	60	60	–	–	–	–
Allocation from domestic energy	60	(17)	1,120	(40)	55.69	63.93
Total Trade	$ 369	$ 232	14,468	10,747	$ 62.41	$ 64.15
Total Energy Costs	$ 543	$ 516	28,408	23,921	$ 50.72	$ 54.51

For the six months ended September 30	*(in millions)*		*(gigawatt hours)*		*($ per MWh)*[2]	
	2007	2006	2007	2006	2007	2006
Hydro	$ 144	$ 110	24,236	18,798	$ 5.98	$ 5.94
Purchases from Independent Power Producers and other long-term contracts	228	198	3,765	3,288	60.67	60.20
Domestic electricity purchases	28	132	559	3,592	50.09	38.00
Thermal	22	39	225	535	96.55	65.52
Transmission charges and other expenses	34	30	49	47	–	–
Allocation to trade energy	(83)	14	(1,524)	(37)	55.94	61.16
Total Domestic	$ 373	$ 523	27,310	26,223	$ 13.67	$ 19.93
Other electricity purchases - Trade[1]	$ 274	$ 146	20,863	19,663	$ 56.14	$ 47.50
Remarketed Gas	315	214	6,226	4,262	50.53	50.21
Transmission charges and other expenses	129	129	–	–	–	–
Allocation from domestic energy	83	(14)	1,524	37	55.94	61.16
Total Trade	$ 801	$ 475	28,613	23,962	$ 59.36	$ 52.69
Total Energy Costs	$1,174	$ 998	55,923	50,185	$ 37.05	$ 35.57

[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 2008 were $543 million, $27 million (five per cent) higher than the second quarter last year, primarily as a result of increased gas trade volumes, offset by lower domestic energy purchases.

For the six months ended September 30, 2007, total energy costs of $1,174 million were $176 million higher than the same period last year, primarily due to higher trade energy volumes at higher average unit prices, offset by lower domestic energy purchases.

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Domestic Energy Costs

Domestic energy costs of $174 million were $110 million or 39 per cent lower than the second quarter of fiscal 2007. The primary reason for the decrease was the reduction of market energy purchases as BC Hydro increased hydro generation to mitigate the impact of higher water inflows and rising storage levels. This was partially offset by increased transmission costs and higher cost purchases from Island Cogeneration Generating Station due to higher output arising from system improvements made in fiscal 2007.

Domestic energy costs of $373 million were $150 million or 29 per cent lower than the six months ended September 30, 2007. The change is primarily a result of the increased use of hydro generation and lower domestic purchases from the market compared with fiscal 2007.

Trade Energy Costs

Trade energy costs of $369 million for the second quarter of fiscal 2008 increased by $137 million, or 59 per cent, compared with the same period last year. This was a result of a greater volume of energy purchases, partially offset by slightly lower average commodity purchase prices. Electricity purchases of 9,534 GWh were eight per cent higher than prior year purchases at three per cent higher average prices. Total gas purchases of 3,814 GWh increased 1,842 GWh or 93 per cent from the previous year at an average gas price 12 per cent lower than last year.

Trade energy costs of $801 million for the six months ended September 30, 2007 increased by $326 million, or 69 per cent, compared with the same period last year. This was the result of higher average commodity purchase prices and increased volumes of electricity and gas purchases. Electricity purchases of 20,863 GWh were six per cent higher than prior year at 18 per cent higher average prices. The volume of gas purchased for sale to third parties increased significantly from 4,262 GWh to 6,226 GWh for the current year and average gas prices were one per cent higher than last year at $51/MWh.

Water Inflows

Water inflows to BC Hydro's reservoirs were 114 per cent higher than average during the second quarter in fiscal 2008 compared with the prior year. As a result of these increased water inflows, BC Hydro increased hydro generation 30 per cent over the prior year, with a resulting decrease in domestic energy purchases. The decision to utilize hydro generation instead of import energy is based on many factors, such as the forecast water inflows, current reservoir levels, forecast market price of energy in future periods relative to the current period, and future demand requirements. Operating constraints related to legal and regulatory obligations such as minimum reservoir levels and stream flow requirements also affect the decision to import energy.

To manage the higher inflows, BC Hydro reservoirs have been managed such that the combined storage in BC Hydro reservoirs at September 30, 2007 was 113 per cent of average compared with 108 per cent of average at September 30, 2006 (average storage levels relate to the average from 1986 to 2007), with the Williston Reservoir on the Peace River system at 113 per cent of average (fiscal 2007 – 104 per cent) and the Kinbasket Reservoir on the Columbia River system at 114 per cent of average (fiscal 2007 – 113 per cent).

Operating Costs

Operations costs for the three and six months ended September 30, 2007 of $61 million and $124 million were $8 million and $11 million higher than in the same period last year. These increases arose from increased demand side management expenses due to increased focus on energy conservation and costs incurred to improve communications and responsiveness during severe storm conditions.

Maintenance costs for the three and six months ended September 30, 2007 of $78 million and $138 million were $8 million and $15 million higher than in the same period in the prior year. The increase for the second quarter was primarily due to increased asset restoration, vegetation maintenance and dam safety costs as a result of unusually severe storms in fiscal 2007 and in preparation for the upcoming winter season. Costs incurred to repair the Cathedral Square substation also contributed to the higher maintenance costs during the period.

Administration costs for the three and six months ended September 30, 2007 of $16 million and $45 million were $10 million and $22 million lower than the prior year. The decrease was due to lower non-current service pension costs resulting from improved returns on the pension plan assets.

Amortization Expense

Amortization expense of $91 million for the second quarter was $5 million higher than for the same period in the previous year due to increased assets in service and asset write-offs, offset by gains realized on the disposal of assets. Amortization expense of $182 million for the six months ended September 30, 2007 was $16 million lower than for the same period in the previous year. This was primarily due to a one-time adjustment recorded in fiscal 2007 to reduce net book values by $24 million as a result of the implementation of the recommendations in a depreciation study undertaken by BC Hydro. This impact is partially offset by an increase in assets in service compared with the prior year.

Finance Charges

Finance charges of $120 million for the second quarter were $4 million higher than for the same period in the previous year. The increase is due to lower U.S. sinking fund income as a result of realized capital losses in the current year compared to the prior year and a higher average volume of debt. These unfavourable variances were partially offset by translations gains as a result of gains on U.S. dollar denominated debt due to the strengthening Canadian dollar and higher interest capitalized during construction.

Finance charges of $232 million for the six months ended September 30, 2007, were $17 million higher than for the same period in the previous year. The increase is due to lower U.S. sinking fund income as a result of realized capital losses in the current year compared to the prior year, a higher average volume of debt, higher short-term interest rates, and foreign exchange translation losses on the revaluation of U.S. sinking funds, net working capital, and U.S. bank balances. This was partially offset by translation gains on unhedged U.S. dollar denominated debt due to the strengthening Canadian dollar and higher interest capitalized during construction.

Accounting Policies

On April 1, 2007, BC Hydro adopted four new accounting standards that were issued by the Canadian Institute of Chartered Accountants (CICA): Handbook Section 1530, Comprehensive Income, Handbook Section 3855, Financial Instruments – Recognition and Measurement, Handbook Section 3861, Financial Instruments – Disclosure and Presentation, and Handbook Section 3865, Hedges. The company adopted these standards retroactively with an adjustment of opening accumulated other comprehensive income and retained earnings; accordingly, comparative amounts for prior periods have not been restated.

Upon adoption of Section 1530 a new category, accumulated other comprehensive income (AOCI), was added to shareholder's equity. Comprehensive income consists of net income and other comprehensive income (OCI). OCI represents changes in shareholder's equity during a period arising from transactions and changes in the fair value of the effective portion of cash flow hedging instruments. Amounts are recorded in OCI until the criteria for recognition in the consolidated statement of income are met.

Section 3855 establishes the recognition and measurement criteria for financial assets, financial liabilities and derivatives. All financial instruments are required to be measured at fair value on initial recognition of the instrument, except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as "held-for-trading", "available-for-sale", "held-to-maturity", "loans and receivables", or "other financial liabilities" as defined by the standard.

Section 3865 expands the guidelines provided in Accounting Guideline 13, Hedging Relationships, by specifying the criteria that must be satisfied in order for hedge accounting to be applied and the accounting for fair value hedges and cash flow hedges. Hedge accounting is discontinued prospectively when the derivative no longer qualifies as an effective hedge, or the derivative is terminated or sold, or upon the sale or early termination of the hedged item.

Refer to note 2 in the interim consolidated financial statements for more detailed discussion and analysis regarding the adoption of these new standards.

Powerex Legal Proceedings

Since 2000, Powerex has been named, in some cases along with other energy providers, as a defendant in a number of lawsuits and U.S. federal regulatory proceedings which seek damages and/or contract rescission based on allegations that, during part of 2000 and 2001, the California wholesale electricity markets were unlawfully manipulated and that the energy prices were not just and reasonable. These proceedings are at various stages. A number of issues and findings are presently on appeal and none has been the subject of final judicial action. The U.S. Court of Appeals for the Ninth Circuit, in its Lockyer decision of July 31, 2006, told the U.S. Federal Energy Regulatory Commission (FERC) that it should reconsider its remedial powers thereby opening up the possibility that refunds will have to be paid for the periods from May to October 2000. Powerex, along with a number of other suppliers, asked the U.S. Supreme Court to hear its appeal of that decision. On June 18, 2007, the Supreme Court denied that application.

On August 2, 2006, the Ninth Circuit ruled on certain issues in the FERC refund proceedings. One of those related to whether refunds should be paid for bilateral sales (those that did not go through the California Independent System Operator (CISO)). In its decision, the Ninth Circuit upheld FERC's decision that refunds should not be paid for bilateral sales but also said that FERC was wrong to conclude that it did not have power to award refunds retroactively.

On August 24, 2007, a Ninth Circuit decision raised questions about its earlier decision that refunds should not be ordered for bilateral purchases. In 2003, FERC denied refunds for bilateral sales in the Pacific Northwest. The August decision reflected FERC's categorical exclusion of bilateral purchases and remanded the case back to FERC for further examination of evidence of market manipulation to determine whether such evidence justified a different conclusion. The precise effect of these decisions on Powerex cannot be determined at this time.

At September 30, 2007, Powerex was owed US $268 million (CDN $267 million) by the markets operated by the California Power Exchange (Cal Px) and the CISO related to Powerex's electricity trade activities in California during fiscal 2001. As a result of payment defaults by a number of California utilities, the Cal Px and CISO were unable to pay these amounts to Powerex. That receivable will be offset against any refunds that Powerex is required to pay.

On March 26, 2004, FERC 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 of energy and ancillary services to the California market throughout the energy crisis. This settlement is still subject to rehearing at FERC, has not been the subject of a final FERC order and FERC's final order when issued may subsequently be appealed to the courts.

BC Hydro was also joined as a defendant in the California Consumer Class Action lawsuit through cross-claims by other defendants. In response to an application by BC Hydro to be dismissed from the lawsuit, a U.S. Federal District Court judge ruled that BC Hydro is immune from these claims in the United States by virtue of the Foreign Sovereign Immunities Act (FSIA). The Ninth Circuit upheld this finding. The court also upheld the District Court's finding that Powerex does not enjoy foreign sovereign entity status and therefore remains a party to the lawsuit, which was ordered to be remanded back to California State Court. Powerex appealed that decision to the Supreme Court of the United States which heard the case on April 16, 2007. On June 18, 2007, the Supreme Court determined it did not have jurisdiction and therefore did not grant Powerex the FSIA order requested. However, the Supreme Court also determined that the Ninth Circuit did not have jurisdiction and therefore that court's decision that Powerex was not an instrumentality of a foreign sovereign, will be set aside.

Due to the ongoing nature and uncertain status of the regulatory and legal proceedings related to the California power markets, management cannot predict at this time the outcome of the claims against Powerex. Powerex has recorded provisions for uncollectible amounts and legal costs associated with the ongoing legal and regulatory impacts of the California energy crisis during fiscal 2001. These provisions are based on management's best estimates, and are intended to adequately provide for any exposure. However, the amounts that may ultimately be collected or paid may differ from management's current estimates. Management has not disclosed the provision amounts or ranges of expected outcomes due to the potentially adverse effect on the process.

Regulation

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 deferral amounts are then included in rates of future periods, subject to approval by the BCUC.

For the three and six months ended September 30, 2007, BC Hydro transferred, on a net basis, $7 million and $135 million, respectively, from regulatory accounts, compared with $147 million and $42 million transferred to regulatory accounts during the same periods last year. The net balance in the regulatory asset and liability accounts as at September 30, 2007, was $293 million compared with $465 million at September 30, 2006.

The reduction in the regulatory energy asset accounts arises from the lower cost of energy supplied during the quarter. The HDA and NHDA regulatory accounts 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 the significantly higher inflows experienced in the current year (114 per cent of average), hydro generation was higher than forecast by 2,472 GWh resulting in lower market purchases required for domestic consumption. The average cost of hydro generation is $5.98 MWh compared with the average cost of $66.03 per MWh for market purchases for the six month period ended September 30, 2007. These factors resulted in the actual domestic energy cost being significantly lower than the forecast cost by $124 million, resulting in a reduction in the regulatory energy asset accounts.

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Rate Design

On March 15, 2007, BC Hydro filed its first Rate Design Application (RDA) since 1991 with the BCUC. The application sought approval from BCUC on a number of changes to BC Hydro's rate design and to its terms and conditions of service to ensure they are fair, efficient and simple. BC Hydro also sought to rebalance rates between customer classes to better match the revenues recovered from each to the costs incurred to serve them. This would have effectively redistributed the total BC Hydro revenue requirement while leaving total revenue unchanged. Following an oral hearing in July, the BCUC issued a preliminary decision on some aspects of the application on September 19, 2007. The BCUC's decision directed BC Hydro to change some of the assumptions contained in BC Hydro's cost of service model, which is used to determine the costs incurred to serve each class of customer. In addition, the BCUC has directed that BC Hydro rebalance rates over three years so that revenues from each customer class exactly match costs incurred to serve each class.

Revelstoke 5 Project

A CPCN application for the addition of a new turbine at the Revelstoke facility with a total expected cost around $330 million was filed with the BCUC on April 13, 2007. A decision approving this project was issued by the BCUC on July 12, 2007 based on an October 2010 in-service date.

BC Hydro – Alcan Electricity Purchase Agreement

This contract, filed with the BCUC on September 5, 2007, replaces last year's agreement with Alcan that was rejected by the BCUC. The 2007 Electricity Purchase Agreement (2007 EPA) meets all of the concerns previously expressed by the BCUC by providing lower prices, extended terms and an increase in capacity and scheduling services.

BC Hydro held a workshop for interveners, BCUC staff and interested parties on September 12, 2007 to receive comments on its report explaining the new agreement and providing analysis supporting its cost-effectiveness. The final report was filed with the BCUC on September 21, 2007. The BCUC has ordered that an oral hearing be held, starting on November 19, 2007. A decision on whether to accept the 2007 EPA is expected to be made by the BCUC in January 2008.

Conservation Research Initiative/Time-of-Use Rate Pilot

BC Hydro filed an application on August 22, 2007 for the second year (November 2007 to November 2008) of this residential rate pilot and received approval for the pilot rates proposed for this test year on October 10, 2007. As part of this pilot, BC Hydro will be testing a Critical Peak Pricing rate which is designed to encourage customers not to use energy when requested by BC Hydro during critical peak hours in the winter months.

Liquidity and Capital Resources

Cash flow provided by operating activities for the second quarter was $103 million compared with $75 million for the same period last year. The increase was primarily due to an increase in net income, a decrease in unrealized gains on mark-to-market, and changes in working capital.

The net long-term debt balance at September 30, 2007 was $7,460 million compared with $6,924 million at March 31, 2007. The increase was a result of long term bond issues totaling $830 million, an increase in revolving borrowings of $153 million, an addition of approximately $145 million of transaction costs, premiums and discounts which have been reclassified to long-term debt to reflect the adopted policy of capitalizing long-term debt transaction costs, premiums and discounts within long-term debt, and withdrawals of $143 million in sinking funds. These increases were partially offset by $542 million of bond maturities and foreign exchange gains of $187 million.

Property, Plant and Equipment Expenditures

Property, plant and equipment expenditures were as follows:

(in millions)	For the three months ended September 30		For the six months ended September 30	
	2007	2006	2007	2006
Distribution improvements and expansion	$ 83	$ 77	$ 165	$ 144
Generation replacements and expansion	77	42	137	72
Transmission lines and substation replacements & expansion	74	61	134	107
General, including computers and vehicles	30	12	44	27
Property, plant and equipment expenditures	$ 264	$ 192	$ 480	$ 350

The increase in distribution improvements and expansion capital expenditures for the three-month period ended September 30, 2007 is primarily due to the replacement of feeder cables and customer driven projects. Generation replacements and expansion expenditures has increased mainly due to several significant improvement projects including the Campbell River Ladore and Strathcona seismic upgrade, capacity expansion at the Aberfeldie Dam, GM Shrum stator and rotor pole replacements, and MICA stator replacements. The increase in transmission activity is primarily due to the construction of the Vancouver Island transmission connect and reinforcement work on the Mission Matsqui area and the replacement of various circuit breakers. The increase in general expenditures is primarily due to the purchase of new properties and building redevelopment work.

The increase in distribution improvements and expansion capital expenditures for the six-month period ended September 30, 2007 is mainly due to the replacement of feeder and submarine cable replacements and increased system improvement work. Generation replacements and expansion expenditures has increased mainly due to several significant improvement projects, including the Campbell River Ladore and Strathcona seismic upgrade, capacity expansion at the Aberfeldie Dam, GM Shrum stator and rotor pole replacements, and the Peace Canyon Turbine Overhaul. The increase in transmission activity is primarily due to replacement and reinforcement work on the Vancouver Island transmission. The increase in general expenditures is primarily due to the purchase of new properties and building redevelopment work.

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.

Unusually high spring water inflows in the Peace River and Columbia River basins in British Columbia have created healthy reservoir levels at BC Hydro electricity generating facilities, which provides a closer balance between BC Hydro's heritage assets and provincial power demand. This improved balance is expected to continue over the remainder of the fiscal year, providing BC Hydro with increased operating flexibility. This should allow BC Hydro to better mitigate the impacts of potentially volatile market energy prices for the balance of fiscal 2008. The possibility of reservoir spill has significantly abated and is expected to be minimal for the remainder of this fiscal year.

Financial

Despite higher reservoir levels, additional electricity supplies will be required to meet peak demand periods, which typically occur during the coldest winter days in November through February. This supply requirement has been accentuated by increasing domestic load growth from BC Hydro customers and a widening gap between the domestic electricity supply and demand. The growth in electricity demand is a result of the strong provincial economy in British Columbia, despite a temporary decline in industrial customer demand during the second quarter as a result of the forestry strike in British Columbia which commenced in July.

BC Hydro is also exposed to financial risk, such as changes in interest rates or foreign exchange rates. During the second quarter those financial risks were relatively stable. Management's assessment of risk is ongoing. Other risks to BC Hydro have not changed materially from the Management Discussion and Analysis in the 2007 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 2007 indicated that income before regulatory accounts for this year was forecast at $324 million and net income forecast at $365 million. BC Hydro prepared an updated forecast in October 2007 that forecasts income before regulatory accounts of $437 million and net income of $365 million for fiscal 2008.

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 October forecast update assumes water inflows return to normal levels, resulting in an average annual rate of 109 per cent, customer load of 53,587 GWh, average market energy prices of US $52.10/MWh, a moderate increase in operating costs, short-term interest rates of 4.80 per cent and a U.S. dollar exchange rate of US $0.9471.

In the current updated forecast, the estimated cumulative rate increase (including the rate rider) for fiscal 2009 to 2011 has changed from 21 per cent in the Service Plan to 25 per cent. To assist customers in mitigating and potentially offsetting the impact of future rate increases, BC Hydro will be actively promoting Power Smart programs and other conservation habits that will help reduce energy consumption. The estimated rate increases are higher largely due to an anticipated increase in government levies (largely property taxes and water rental rates), higher finance charges arising from an increased in forecasted interest rates, and an increase in operating costs needed to support the execution of key initiatives to service and maintain an aging infrastructure. The forecast rate increases are indicative only and have not been approved by the BCUC. The forecast rate increases are subject to change given the volatility around several assumptions including water inflows and market prices for energy.

Financial

CONSOLIDATED STATEMENT OF OPERATIONS

(Unaudited)	For the three months ended September 30		For the six months ended September 30	
(in millions)	2007	2006	2007	2006
Revenues				
Domestic	$ 667	$ 627	$ 1,332	$ 1,242
Trade	444	335	937	709
	$1,111	$ 962	$ 2,269	$ 1,951
Expenses				
Energy costs:				
Domestic	174	284	373	523
Trade	369	232	801	475
Operations	61	53	124	113
Maintenance	78	70	138	123
Administration	16	26	45	67
Taxes	38	38	77	75
Amortization	91	86	182	198
	827	789	1,740	1,574
Operating Income	284	173	529	377
Finance charges	(120)	(116)	(232)	(215)
Income Before Regulatory Account Transfers	164	57	297	162
Net change in regulatory accounts (note 4)	(7)	147	(135)	42
Net Income	$ 157	$ 204	$ 162	$ 204

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(Unaudited)	For the three months ended September 30		For the six months ended September 30	
(in millions)	2007	2006	2007	2006
Net Income	157	$ 204	$ 162	$ 204
Other Comprehensive Income (note 6)	39	–	66	–
Comprehensive Income	196	204	$ 228	204

See accompanying notes to the interim consolidated financial statements.

Financial

CONSOLIDATED BALANCE SHEET

(Unaudited) (in millions)	As at September 30 2007	As at March 31 2007
ASSETS		
Property, Plant and Equipment, net	$ 10,303	$ 10,002
Current Assets		
Cash and cash equivalents	9	8
Accounts receivable and accrued revenue	438	512
Materials and supplies	189	137
Prepaid expenses	125	110
Mark-to-market gains	99	61
	860	828
Other Assets and Deferred Charges		
Intangible assets	419	424
Sinking funds	574	733
Regulatory assets (note 4)	741	874
	1,734	2,031
	$ 12,897	$ 12,861
LIABILITIES AND EQUITY		
Long-term debt net of sinking funds	$ 6,376	$ 5,502
Sinking funds presented as assets	574	733
Long-Term Debt	6,950	6,235
Current Liabilities		
Current portion of long-term debt	1,084	1,422
Accounts payable and accrued liabilities	929	1,267
Mark-to-market losses	232	43
	2,245	2,732
Other Liabilities		
Regulatory liabilities (note 4)	448	429
Deferred contributions	948	913
Debt issue and related costs (note 2)	–	145
Other long-term liabilities	442	459
Foreign currency contracts (note 2)	–	165
	1,838	2,111
Shareholder's Equity (note 6)	1,864	1,783
	$ 12,897	$ 12,861

Commitments and Contingencies (note 7)

See accompanying notes to the interim consolidated financial statements.

Approved on behalf of the Board:

L.I. (Larry) Bell
Chair

W.C. (Wanda) Costuros
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)	2007	2006	2007	2006
Operating Activities				
Net income	$ 157	$ 204	$ 162	$ 204
Regulatory account transfers	(12)	(191)	95	(98)
Adjustments for non-cash items:				
Amortization of regulatory accounts	19	45	40	56
Amortization expense	91	85	182	197
Foreign exchange translation gains	(10)	–	(22)	(7)
Deferred revenue	7	–	7	–
Amortization of debt issue and related costs	(1)	(3)	(2)	(5)
Unrealized gains on mark-to-market	1	9	(19)	(31)
Sinking fund income	(5)	(10)	(10)	(19)
Employee benefit plan expenses	–	7	–	14
Other non-cash items	(1)	6	6	8
	246	152	439	319
Working capital changes	(143)	(77)	(150)	(155)
Cash provided by operating activities	103	75	289	164
Investing Activities				
Property, plant and equipment expenditures	(265)	(200)	(490)	(349)
Deferred contributions	27	21	50	50
Proceeds from property sales	–	(2)	–	–
Other items	(4)	(2)	(8)	(7)
Cash used for investing activities	(242)	(183)	(448)	(306)
Financing Activities				
Bonds:				
Issued	–	300	830	300
Retired	(9)	–	(542)	–
Revolving borrowings	28	(217)	153	28
Sinking fund withdrawals	4	–	143	–
Deferred debt costs	–	27	–	27
Settlement of derivative instruments	(2)		(93)	–
Payment to the Province	–	–	(331)	(223)
Cash provided by financing activities	21	110	160	132
Increase (decrease) in cash and cash equivalents	(118)	2	1	(10)
Cash and cash equivalents, beginning of period	127	11	8	23
Cash and cash equivalents, end of period	9	13	9	$ 13
Supplemental disclosure of cash flow information				
Interest paid	$ 120	$ 122	$ 252	$ 255

See accompanying notes to the interim consolidated financial statements

NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED) SEPTEMBER 30, 2007

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 4) 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 2007 Annual Report.

Except for as noted below in note 2, these interim consolidated financial statements follow the same accounting policies as those described in BC Hydro's 2007 Annual Report.

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

Note 2: Adoption of New Accounting Policy

On April 1, 2007, BC Hydro adopted four new accounting standards that were issued by the Canadian Institute of Chartered Accountants (CICA): Handbook Section 1530, Comprehensive Income, Handbook Section 3855, Financial Instruments – Recognition and Measurement, Handbook Section 3861, Financial Instruments – Disclosure and Presentation, and Handbook Section 3865, Hedges. BC Hydro adopted these standards retroactively with an adjustment of opening retained earnings and accumulated other comprehensive income; accordingly, comparative amounts for prior periods have not been restated.

Comprehensive Income

As a result of adopting these standards, a new category – accumulated other comprehensive income (AOCI) – was added to shareholder's equity. Comprehensive income consists of net income and other comprehensive income (OCI). OCI represents changes in shareholder's equity during a period arising from transactions and changes in the fair value of available for sale securities and the effective portion of cash flow hedging instruments. Amounts are recorded in OCI until the criteria for recognition in the consolidated statement of operations are met.

Financial Instruments – Recognition and Measurement

Section 3855 establishes the recognition and measurement criteria for financial assets, financial liabilities and derivatives. All financial instruments are required to be measured at fair value on initial recognition of the instrument, except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as "held-for-trading", "available-for-sale", "held-to-maturity", "loans and receivables", or "other financial liabilities" as defined by the standard. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading. For other financial instruments, transaction costs are capitalized on initial recognition.

Financial assets and financial liabilities held-for-trading are measured at fair value with changes in those fair values recognized in income. Financial assets classified as "available-for-sale" are measured at fair value, with changes in those fair values recognized in OCI. Financial assets and liabilities classified as held-to-maturity are measured at amortized cost using the effective interest method of amortization. All derivatives, including embedded derivatives that are not closely related to the host contract and must be separately accounted for, generally must be classified as held-for-trading and recorded at fair value in the consolidated balance sheet. BC Hydro has selected April 1, 2007 as the transition date for recognizing embedded derivatives and, therefore, recognizes as separate assets and liabilities only those derivatives embedded in hybrid instruments issued, acquired, or substantially modified on or after April 1, 2007. All regular-way purchases or sales of financial assets are accounted for on a settlement date basis.

Hedges

Section 3865 expands the guidelines provided in Accounting Guideline 13, Hedging Relationships, by specifying the criteria that must be satisfied in order for hedge accounting to be applied and the accounting for fair value hedges and cash flow hedges. Hedge accounting is discontinued prospectively when the derivative no longer qualifies as an effective hedge, or the derivative is terminated or sold, or upon the sale or early termination of the hedged item.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for unrealized gains or losses attributable to the hedged risk and recognized in net income. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging derivative, which is also recorded in net income. When hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to net income over the remaining term of the original hedging relationship.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income. The ineffective portion is recognized in net income. The amounts recognized in accumulated other comprehensive income are reclassified to net income in the periods in which net income is affected by the variability in the cash flows of the hedged item.

Impact upon Adoption

The transition adjustments attributable to the re-measurement of financial assets and financial liabilities at fair value were recognized in retained earnings as at April 1, 2007. Adjustments arising from re-measuring financial assets classified as available-for sale or from the effective portion of derivatives designated as cash flow hedges at fair value were recognized in opening AOCI as at April 1, 2007.

The transition amounts that were recorded in the opening retained earnings or in the opening accumulated other comprehensive income balance on April 1, 2007 were as follows:

(in millions)	Opening Retained Earnings	Opening Accumulated Other Comprehensive Income
Change in accounting policy from the straight line method to the effective interest method for amortization	$ (6)	$ –
Opening ineffective portion of fair value hedges	7	–
Fair value adjustment upon reclassification of sinking funds to available-for-sale	–	1
Opening fair value adjustment of cash flow hedges	–	(21)
Transition Adjustments	$ 1	$ (20)

With the adoption of Section 3855, $145 million of transaction costs, premiums and discounts have been reclassified to long-term debt from debt issue and related costs to reflect the adopted policy of capitalizing long-term debt transaction costs, premiums and discounts within long-term debt. The costs capitalized within long-term debt will be amortized using the effective interest method. BC Hydro's policy is to recognize transaction costs associated with financial assets and liabilities, that are classified as other than held for trading, as an adjustment to the cost of those financial assets and liabilities recorded in the balance sheet. These transaction costs are amortized into earnings using the effective interest rate method over the life of the related financial instrument. Previously, BC Hydro deferred these costs within other assets and amortized them straight-line over the life of the related long-term debt.

The following table provides a comparison of carrying values for non-derivative financial instruments as at September 30, 2007, and March 31, 2007:

	September 30, 2007		**March 31, 2007**	
(in millions)	Carrying Value	Fair Value	Carrying Value	Fair Value
Held for Trading:				
Revolving Borrowings – Cdn	$ (990)	$ (990)	$ (826)	$ (826)
Revolving Borrowings – US	–	–	(10)	(10)
Available for Sale:				
Sinking Funds – Cdn	$ 490	$ 490	$ 509	$ 512
Sinking Funds – US	–	–	129	127
Held to Maturity:				
Sinking Funds – US	$ 84	$ 85	$ 95	$ 97
Long Term Debt	$ (7,044)	$ (7,952)	$ (6,821)	$ (8,075)

For assets classified as held-for-trading, no amount has been recognized in net income for the period relating to changes in fair value. For available-for-sale financial assets, $9.8 million has been recorded in other comprehensive income and $5.4 million 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:

	September 30, 2007		**March 31, 2007**	
(in millions)	Carrying Value	Fair Value	Carrying Value	Fair Value
Designated Hedges:				
Foreign currency contracts	$ (181)	$ (181)	$ (165)	$ (167)
Interest rate swaps	6	6	–	8
Commodity derivatives	1	1	–	(13)
Non-designated Hedges				
Foreign currency contracts	(4)	(4)	–	–
Commodity derivatives	30	30	17	14

For the three and six months ended September 30, 2007, no net gain or loss 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, 2007, a loss of $25 million and $99 million was recognized in other comprehensive income and a gain of $58 million and $170 million was removed from accumulated other comprehensive income and reported in net income, offsetting foreign exchange gains recorded during the period.

For derivatives not designated as hedging instruments, $2 million and $9 million was recognized in trade and other revenue and no net gain or loss was recognized in finance charges for the three and six months ended September 30, 2007. Charges recorded using the effective interest rate method were not materially different from the straight-line depreciation method for the three and six months ended September 30, 2007.

Note 3: 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 4: 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 year the amounts are incurred. These accounting policies support BC Hydro's regulation and have been established through ongoing application by approval of the BCUC.

During the first quarter, BC Hydro requested and received regulatory approval for the establishment of the fiscal 2007 Unplanned Major Storm Restoration Costs regulatory account, which is included in Other Regulatory Accounts. BC Hydro also received BCUC approval to include in this account certain expenditures incurred in fiscal 2008 related to improving outage communication and system resiliency.

Regulatory Accounts

The following regulatory assets and liabilities have been established through rate regulation. For the six months ended September 30, 2007, the impact of regulatory accounting has resulted in a decrease to net income of $135 million (2006 – $42 million increase).

(in millions)	April 1, 2007	Accounting Policy Change	Addition (Reduction)	Amortization	Net change	September 30, 2007
Regulatory Assets						
Heritage Deferral Account	$ 178	$ –	$ (86)	$ (23)	$ (109)	$ 69
Non-Heritage Deferral Account	209	–	(31)	(27)	(58)	151
BCTC Deferral Account	13	–	13	(1)	12	25
Demand-Side Management Programs	282	–	24	(18)	6	288
First Nation Negotiations, Litigation and Settlement Costs	122	–	5	(1)	4	126
Other Regulatory Accounts	70	–	8	4	12	82
Total Regulatory Assets	$ 874	$ –	$ (67)	$ (66)	$ (133)	$ 741
Regulatory Liabilities						
Future Removal and Site Restoration Costs	$ 210	$ –	$ –	$ (8)	$ (8)	$ 202
Trade Income Deferral Account	203	–	6	(26)	(20)	183
Foreign Exchange Gains and Losses	16	17	22	8	30	63
Total Regulatory Liabilities	$ 429	$ 17	$ 28	$ (26)	$2	$ 448
Net	$ 445	$ (17)	$ (95)	$ (40)	$ (135)	$ 293

With the adoption of Section 3855 certain financial instruments that had previously been deferred as part of the Foreign Exchange Gains and Losses regulatory account have been reclassified to Mark-to-market gains.

Note 5: Employee Future Benefits

BC Hydro's cost for employee future benefits for the three and six months ended September 30, 2007 was $11 million and $22 million respectively (2006 – $17 million and $34 million).

Note 6: Shareholder's Equity

Consolidated Statement of Comprehensive Income

	For the three months ended September 30		For the six months ended September 30	
(in millions)	2007	2006	2007	2006
Other Comprehensive Income				
Unrealized gain (loss) on sinking fund balances	3		(10)	
Reclassification to income of loss on sinking funds	3	–	5	–
Unrealized loss on derivatives designated as cash flow hedges	(24)	–	(98)	–
Reclassification to income of loss on derivatives designated as cash flow hedge	57	–	169	–
Other Comprehensive Income	39	–	66	–

Statement of Shareholder's Equity

	For the six months ended September 30	
(in millions)	2007	2006
Retained earnings, beginning of period	$ 1,783	1,707
Change in accounting policy (note 2)	1	–
Net income	162	204
Accrued Payment to the Province	(128)	(167)
Retained earnings, end of period	$ 1,818	$ 1,744
Accumulated other comprehensive income, beginning of period	–	–
Transition adjustment upon change in accounting policy (note 2)	(20)	–
Other comprehensive income for the period	66	–
Accumulated other comprehensive income, end of period	46	–
Shareholder's Equity	$ 1,864	$ 1,744

Note 7: Commitments and Contingencies

Long-term Energy Purchase Contract

On August 16, 2007, BC Hydro entered into a new long-term energy purchase contract with Alcan Inc., replacing the November 1, 2006 agreement rejected by the BCUC. The revised contract was submitted to the BCUC for approval on September 5, 2007, and is subject to their acceptance before finalization. Once approved, energy purchases are expected to commence on October 1, 2007 and continue until December 31, 2034.

Powerex Legal Proceedings

Since 2000, Powerex has been named, in some cases along with other energy providers, as a defendant in a number of lawsuits and U.S. federal regulatory proceedings which seek damages and/or contract rescission based on allegations that, during part of 2000 and 2001, the California wholesale electricity markets were unlawfully manipulated and that the energy prices were not just and reasonable. These proceedings are at various stages. A number of issues and findings are presently on appeal and none has been the subject of final judicial action. The U.S. Court of Appeals for the Ninth Circuit, in its Lockyer decision of July 31, 2006, told the U.S. Federal Energy Regulatory Commission (FERC) that it should reconsider its remedial powers thereby opening up the possibility that refunds will have to be paid for the periods from May to October 2000. Powerex, along with a number of other suppliers, asked the U.S. Supreme Court to hear its appeal of that decision. On June 18, 2007, the Supreme Court denied that application.

Financial

On August 2, 2006, the Ninth Circuit ruled on certain issues in the FERC refund proceedings. One of those related to whether refunds should be paid for bilateral sales (those that did not go through the California Independent System Operator (CISO)). In its decision, the Ninth Circuit upheld FERC's decision that refunds should not be paid for bilateral sales but also said that FERC was wrong to conclude that it did not have power to award refunds retroactively.

On August 24, 2007, a Ninth Circuit decision raised questions about its earlier decision that refunds should not be ordered for bilateral purchases. In 2003, FERC denied refunds for bilateral sales in the Pacific Northwest. The August decision reflected FERC's categorical exclusion of bilateral purchases and remanded the case back to FERC for further examination of evidence of market manipulation to determine whether such evidence justified a different conclusion. The precise effect of these decisions on Powerex cannot be determined at this time.

At September 30, 2007, Powerex was owed US $268 million (CDN $267 million) by the markets operated by the California Power Exchange (Cal Px) and the CISO related to Powerex's electricity trade activities in California during fiscal 2001. As a result of payment defaults by a number of California utilities, the Cal Px and CISO were unable to pay these amounts to Powerex. That receivable will be offset against any refunds that Powerex is required to pay.

On March 26, 2004, FERC 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 of energy and ancillary services to the California market throughout the energy crisis. This settlement is still subject to rehearing at FERC, has not been the subject of a final FERC order and FERC's final order when issued may subsequently be appealed to the courts.

BC Hydro was also joined as a defendant in the California Consumer Class Action lawsuit through cross-claims by other defendants. In response to an application by BC Hydro to be dismissed from the lawsuit, a U.S. Federal District Court judge ruled that BC Hydro is immune from these claims in the United States by virtue of the Foreign Sovereign Immunities Act (FSIA). The Ninth Circuit upheld this finding. The court also upheld the District Court's finding that Powerex does not enjoy foreign sovereign entity status and therefore remains a party to the lawsuit, which was ordered to be remanded back to California State Court. Powerex appealed that decision to the Supreme Court of the United States which heard the case on April 16, 2007. On June 18, 2007, the Supreme Court determined it did not have jurisdiction and therefore did not grant Powerex the FSIA order requested. However, the Supreme Court also determined that the Ninth Circuit did not have jurisdiction and therefore that court's decision that Powerex was not an instrumentality of a foreign sovereign, will be set aside.

Due to the ongoing nature and uncertain status of the regulatory and legal proceedings related to the California power markets, management cannot predict at this time the outcome of the claims against Powerex. Powerex has recorded provisions for uncollectible amounts and legal costs associated with the ongoing legal and regulatory impacts of the California energy crisis during fiscal 2001. These provisions are based on management's best estimates, and are intended to adequately provide for any exposure. However, the amounts that may ultimately be 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.

FOR GENERATIONS

GDS07-312 November 2007