# SECOND QUARTER REPORT FISCAL 2012

BC hydro
REGENERATION

BRITISH COLUMBIA

# BC HYDRO & POWER AUTHORITY MANAGEMENT DISCUSSION AND ANALYSIS

## For the three and six months ended September 30, 2011

## Dated November 25, 2011

The Management Discussion and Analysis reports on British Columbia Hydro and Power Authority's (BC Hydro or the Company) consolidated results and financial position for the three and six month periods ended September 30, 2011 (fiscal 2012). This section should be read in conjunction with the Management Discussion and Analysis presented in the 2011 Annual Report, the 2011 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, 2011 and 2010. 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 2012 benefited from higher energy trading margins, offset by lower domestic gross margins, higher operating costs and higher finance charges than in the same quarter in the prior year.

## HIGHLIGHTS

- On April 21, 2011 the British Columbia Utilities Commission (BCUC) approved an average interim rate increase of 8 per cent effective May 1, 2011. The BCUC suspended the regulatory process for reviewing BC Hydro's F2012 – F2014 Revenue Requirements Application (RRA) until completion of a government review of BC Hydro. The outcome of this review was issued on August 11, 2011 and was incorporated into an amended revenue requirement application to the BCUC filed on November 24, 2011 (Amended RRA). The financial results for the three and six month periods ended September 30, 2011 reflect the Amended RRA with the cumulative impact of such changes being recorded as a change in estimate in the second quarter. The financial impact for the quarter and the six months ended September 30, 2011 was a $5 million reduction of net income.
- After two successive low water years in which system water inflows for fiscal 2011 and 2010 were 86 and 87 per cent of average, respectively, inflows for fiscal 2012 are forecast to be 107 per cent of average. At September 30, 2011, the combined system storage in BC Hydro reservoirs was 113 per cent of average compared to 94 per cent of average at September 30, 2010.
- BC Hydro's capital plan for fiscal 2012 is $2.1 billion, an increase of $400 million over fiscal 2011, as the Company continues its programs to address load growth and renew and revitalize its aging infrastructure. Property, plant and equipment expenditures for the quarter of $487 million were $68 million higher than in the same period in the prior year primarily due to higher expenditures on generation replacement and expansion projects, transmission projects, and on the Smart Metering and Infrastructure Program (SMI).

| | *For the three months ended September 30* | | | *For the six months ended September 30* | | |
|---|---|---|---|---|---|---|
| *(in millions)* | **2011** | 2010 | Change | **2011** | 2010 | Change |
| Net Income | **$ 63** | $ 119 | $ (56) | **$ 155** | $ 210 | $ (55) |
| Accrued Payment to the Province | **$ —** | $ 70 | $ (70) | **$ —** | $ 70 | $ (70) |
| Number of Domestic Customers | **N/A** | N/A | N/A | **1,860,444** | 1,842,293 | 18,151 |
| GWh Sold (Domestic) | **11,447** | 11,432 | 15 | **23,258** | 22,684 | 574 |
| Total Reservoir Storage (GWh) | **N/A** | N/A | N/A | **30,420** | 25,623 | 4,797 |

| *(in millions)* | *As at September 30, 2011* | *As at March 31, 2011* | *Change* |
|---|---|---|---|
| Total Assets | **$ 20,033** | $ 19,479 | $ 554 |
| Retained Earnings | **$ 2,902** | $ 2,747 | $ 155 |
| Debt to Equity | **81 : 19** | 80 : 20 | N/A |

## CONSOLIDATED RESULTS OF OPERATIONS

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

The transfers to regulatory accounts reflected in net income on the consolidated statement of operations include: variances between forecast and actual amounts for certain costs, including cost of energy, trade income and finance charges; certain amounts incurred in the current period that are deferred for future recovery in rates (such as demand-side management expenditures and liability provisions); annual deferral or recoveries of revenue over the F2012 to F2014 period in order to smooth the rate increases applied for in BC Hydro's F2012–F2014 RRA evenly over the three-year period covered by the application; interest accrued on regulatory accounts where allowed; and amortization of regulatory accounts into income. Transfers to regulatory accounts during the three months ended September 30, 2011 reduced net income by $24 million and increased net income by $1 million for the six months ended September 30, 2011. In addition, on April 21, 2011, the BCUC approved an average interim rate increase for fiscal 2012 of 8 per cent effective May 1, 2011 which is included in the results.

Net income for the three months ended September 30, 2011 was $63 million, $56 million lower than the three months ended September 30, 2010. On a year to date basis, net income was $155 million, $55 million lower than the same period in 2010. The decrease in net income for the three and six months ended September 30, 2011 over the comparable period in 2010 was primarily due to the following:

- In the quarter, domestic margins were $33 million lower than in the same period in the prior year due to the impact of the year to date cumulative adjustment to regulatory transfers to align with the rate increase applied for in the Amended RRA. For the six months ended September 30, 2011, domestic margins were $65 million higher, reflecting higher revenues due to higher average customer rates in the current year;
- Other operating costs were $29 million and $88 million higher for the three and six months ended September 30, 2011, respectively, than in the comparable periods in the prior year primarily due to higher amortization expense and foreign exchange revaluation losses due to weakening of the Canadian dollar in the second quarter;
- Finance charges after regulatory transfers were $8 million and $25 million higher than the comparable periods in the prior year primarily due to higher debt levels to support capital spending.

# REVENUES

| | (in millions) | | (gigawatt hours) | |
|---|---|---|---|---|
| | | (Revised)[2] | | (Revised)[2] |
| *For the three months ended September 30* | **2011** | 2010 | **2011** | 2010 |
| **Domestic** | | | | |
| Residential | **$ 286** | $ 274 | **3,405** | 3,460 |
| Light industrial and commercial | **324** | 301 | **4,408** | 4,373 |
| Large industrial | **144** | 134 | **3,374** | 3,290 |
| Other energy sales | **53** | 66 | **260** | 309 |
| Total Domestic Revenue Before Regulatory Transfer | **807** | 775 | **11,447** | 11,432 |
| Domestic rate smoothing and load variance regulatory transfer | **(59)** | (8) | **—** | — |
| **Total Domestic** | **$ 748** | $ 767 | **11,447** | 11,432 |
| **Trade** | | | | |
| Electricity – Gross | **$ 356** | $ 290 | **8,429** | 6,658 |
| Less: forward electricity purchases[1] | **(85)** | (217) | **—** | — |
| Electricity – Net | **271** | 73 | **—** | — |
| Gas – Gross | **241** | 200 | **6,061** | 4,135 |
| Less: forward gas purchases[1] | **(108)** | (167) | **—** | — |
| Gas – Net | **133** | 33 | **—** | — |
| **Total Trade** | **$ 404** | $ 106 | **14,490** | 10,793 |
| **Total** | **$ 1,152** | $ 873 | **25,937** | 22,225 |

| | (in millions) | | (gigawatt hours) | |
|---|---|---|---|---|
| | | (Revised)[2] | | (Revised)[2] |
| *For the six months ended September 30* | **2011** | 2010 | **2011** | 2010 |
| **Domestic** | | | | |
| Residential | **$ 632** | $ 555 | **7,546** | 7,090 |
| Light industrial and commercial | **638** | 603 | **8,671** | 8,631 |
| Large industrial | **278** | 259 | **6,557** | 6,413 |
| Other energy sales | **97** | 118 | **484** | 550 |
| Total Domestic Revenue Before Regulatory Transfer | **1,645** | 1,535 | **23,258** | 22,684 |
| Domestic rate smoothing and load variance regulatory transfer | **(11)** | 17 | **—** | — |
| **Total Domestic** | **$ 1,634** | $ 1,552 | **23,258** | 22,684 |
| **Trade** | | | | |
| Electricity – Gross | **$ 606** | $ 547 | **16,667** | 13,720 |
| Less: forward electricity purchases[1] | **(156)** | (339) | **—** | — |
| Electricity – Net | **450** | 208 | **—** | — |
| Gas – Gross | **526** | 380 | **13,107** | 9,302 |
| Less: forward gas purchases[1] | **(377)** | (295) | **—** | — |
| Gas – Net | **149** | 85 | **—** | — |
| **Total Trade** | **$ 599** | $ 293 | **29,774** | 23,022 |
| **Total** | **$ 2,233** | $ 1,845 | **53,032** | 45,706 |

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

[2] *Trade revenue regulatory transfer is netted with the trade cost of energy transfer to reflect a trade margin transfer.*

Total revenue for the three and six month periods ended September 30, 2011 was $1,152 million and $2,233 million, respectively, increases of $279 million and $388 million, respectively, compared with the same periods in the prior year. Domestic revenues decreased in the quarter due to recognition of the change in the applied for rate increase for fiscal 2012 from 9.73 per cent to 8 per cent and adjustment to the Rate Smoothing Account regulatory transfers as per the Amended RRA filed on November 24, 2011 for which the cumulative year to date impacts were recognized in the quarter. Year to date domestic revenues were higher due to higher average customer rates in all customer classes and higher consumption by residential and large industrial customers. Trade revenues increased due to higher gas and electricity trade sales volumes and higher gas prices in both the three and six month periods.

## DOMESTIC REVENUES

Total domestic revenues after regulatory transfers for the three months ended September 30, 2011 were $748 million, a $19 million decrease over the comparable period in the prior year. Total domestic revenues after regulatory transfers for the six months ended were of $1,634 million, an increase of $82 million over the comparable period in the prior year. Domestic revenues before regulatory account transfers were higher in the three and six months ended September 30, 2011 due mainly to the interim average rate increase approved by the BCUC of 8 per cent effective May 1, 2011. For the three months ended September 30, 2011, domestic revenues after regulatory transfers were lower than in the same period in the prior year due primarily to:

- The impact in the quarter of a change in the applied for fiscal 2012 rate increase from 9.73 per cent to 8 per cent as per the Amended RRA filed on November 24, 2011.
- An adjustment to the Rate Smoothing Regulatory Account transfer for the cumulative year to date impact of the change in the rate increase applied for in the Amended RRA.

The increase in domestic revenue for the six months ended September 30, 2011 was primarily due to higher average customer rates in the current fiscal year, reflecting the 8 per cent interim rate increase. Domestic sales volumes for the six months were higher due to increased consumption by residential customers primarily due to colder weather conditions and by large industrial customers primarily as a result of the temporary closure of a plant in the Chemicals sector for an upgrade in fiscal 2011 which significantly reduced consumption in that fiscal year. Variances between actual and planned load are deferred to the Non-Heritage Deferral Account (NHDA).

## TRADE REVENUES

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

BC Hydro's electricity system is interconnected with systems in Alberta and the Western United States, facilitating sales and purchases of electricity outside of British Columbia. Powerex's trade activities help BC Hydro balance its system by being able to import energy to meet domestic demand when there is a supply shortage in the system due to such factors as low water inflows. Exports are made only after ensuring domestic demand requirements can be met.

Gross trade revenue for the three months ended September 30, 2011 was $597 million, an increase of $107 million over the comparable period in prior year due to an increase of $66 million in gross electricity sales and an increase in gross gas revenue of $41 million. The increase in gross electricity sales was primarily driven by a 27 per cent increase in electricity sales volumes, partially offset by a decrease in the average electricity sales price of 13 per cent. The decrease in average electricity sales price was primarily due to lower Pacific Northwest prices as a result of higher water levels in the second quarter of current fiscal year, partially offset by higher sales prices into Alberta due to generation limitations in that province. The increase in gas revenue was primarily driven by a 47 per cent increase in gas sales volumes reflecting Powerex's increased gas trading activity, partially offset by a 5 per cent decrease in gas sales prices over the prior year. Deducted from gross trade revenue are forward purchases, which decreased by a net $191 million compared with the prior year. Forward transactions are reported on a net basis in accordance with GAAP.

Gross trade revenue for the six months ended September 30, 2011 was $1,132 million, an increase of $205 million over the comparable period in the prior year due to an increase in gross gas revenue of $146 million and an increase in gross electricity revenue of $59 million. The increase in gas revenue was primarily driven by a 41 per cent in increase in the average gas sales price over the prior year. The increase in gross electricity revenue was due to a 21 per cent increase in electricity sales volumes, partially offset by a decrease in the average electricity sales price of 20 per cent. The decrease in average electricity sales price was primarily due to lower Pacific Northwest prices as a result of higher water levels in the current fiscal year, partially offset by higher Alberta prices due to generation limitations in that province. Deducted from gross trade revenue are forward purchases, which decreased by a net $101 million compared with the prior year. Forward transactions are reported on a net basis in accordance with GAAP. Variances between actual and planned trade revenue are deferred to the Trade Income Deferral Account (TIDA).

## OPERATING COSTS

For the three and six months ended September 30, 2011, total operating costs of $970 million and $1,836 million were $327 million and $418 million higher, respectively, than in the same periods in the prior year. The increase in the quarter was primarily due to increases in the cost of energy due to higher planned domestic and trade energy costs and to higher amortization expense due to more assets in service. Year to date, the increase was due to higher cost of energy, higher amortization expense, and higher personnel expenditures, partially offset by higher capitalized operating costs.

### COST OF ENERGY

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

Energy costs are comprised of the following sources of supply:

| | *(in millions)* | | *(gigawatt hours)* | | *($ per MWh)* | |
|---|---|---|---|---|---|---|
| | | *(Revised)*[5] | | *(Revised)*[5] | | *(Revised)*[5] |
| *For the three months ended September 30* | **2011** | 2010 | **2011** | 2010 | **2011**[4] | 2010[4] |
| **Domestic** | | | | | | |
| Water rental payments (hydro generation)[1] | **$ 88** | $ 57 | **11,914** | 7,196 | **$ 7.35** | $ 7.92 |
| Purchases from Independent Power Producers | **214** | 206 | **3,259** | 3,440 | **65.81** | 59.77 |
| Other electricity purchases – Domestic | **—** | 63 | **1** | 1,639 | **—** | 38.35 |
| Gas for thermal generation | **7** | 11 | **15** | 58 | **461.22** | 196.81 |
| Transmission charges and other expenses[2] | **(4)** | 4 | **22** | 14 | **—** | — |
| Allocation (to) from trade energy | **(76)** | 7 | **(2,219)** | 133 | **33.97** | 43.86 |
| Total Domestic Cost of Energy Before Regulatory Transfers | **229** | 348 | **12,992** | 12,480 | **17.62** | 27.87 |
| Domestic cost of energy regulatory transfers | **21** | (112) | **—** | — | **—** | — |
| **Total Domestic** | **$ 250** | $ 236 | **12,992** | 12,480 | **$ 17.62** | $ 27.87 |
| **Trade** | | | | | | |
| Electricity – Gross | **$ 149** | $ 240 | **5,708** | 6,627 | **$ 26.10** | $ 36.22 |
| Less: forward electricity purchases[3] | **(85)** | (217) | **—** | — | **—** | — |
| Electricity – Net | **64** | 23 | **—** | — | **—** | — |
| Remarketed gas – Gross | **230** | 177 | **6,424** | 4,029 | **35.80** | 43.93 |
| Less: forward gas purchases[3] | **(108)** | (167) | **—** | — | **—** | — |
| Remarketed gas – Net | **122** | 10 | **—** | — | **—** | — |
| Transmission charges and other expenses | **57** | 41 | **—** | — | **—** | — |
| Allocation from (to) domestic energy | **76** | (7) | **2,219** | (133) | **33.97** | 43.86 |
| Total Trade Cost of Energy Before Regulatory Transfers | **319** | 67 | **14,351** | 10,523 | **28.18** | 26.95 |
| Trade net margin regulatory transfers | **(5)** | (37) | **—** | — | **—** | — |
| **Total Trade** | **$ 314** | $ 30 | **14,351** | 10,523 | **$ 27.83** | $ 23.44 |
| **Total Energy Costs** | **$ 564** | $ 266 | **27,343** | 23,003 | **$ 23.74** | $ 20.98 |

| | (in millions) | | (gigawatt hours) | | ($ per MWh) | |
|---|---|---|---|---|---|---|
| | | (Revised)[5] | | (Revised)[5] | | (Revised)[5] |
| *For the six months ended September 30* | **2011** | 2010 | **2011** | 2010 | **2011**[4] | 2010[4] |
| **Domestic** | | | | | | |
| Water rental payments (hydro generation)[1] | **$ 162** | $ 121 | **21,692** | 15,796 | **$ 7.54** | $ 7.89 |
| Purchases from Independent Power Producers | **369** | 354 | **5,819** | 5,964 | **63.49** | 59.29 |
| Other electricity purchases – Domestic | **11** | 84 | **557** | 2,316 | **20.45** | 36.21 |
| Gas for thermal generation | **15** | 21 | **44** | 99 | **338.76** | 216.31 |
| Transmission charges and other expenses[2] | **(1)** | 24 | **48** | 39 | **—** | — |
| Allocation (to) from trade energy | **(84)** | 32 | **(2,348)** | 752 | **33.02** | 40.84 |
| Total Domestic Cost of Energy Before Regulatory Transfers | **472** | 636 | **25,812** | 24,966 | **18.28** | 25.47 |
| Domestic cost of energy regulatory transfers | **44** | (137) | **—** | — | **—** | — |
| Total Domestic | **$ 516** | $ 499 | **25,812** | 24,966 | **$ 20.00** | $ 19.99 |
| **Trade** | | | | | | |
| Electricity – Gross | **$ 287** | $ 440 | **13,529** | 14,176 | **$ 21.21** | $ 31.04 |
| Less: forward electricity purchases[3] | **(156)** | (339) | **—** | — | **—** | — |
| Electricity – Net | **131** | 101 | **—** | — | **—** | — |
| Remarketed gas – Gross | **505** | 348 | **13,515** | 9,279 | **37.37** | 37.50 |
| Less: forward gas purchases[3] | **(377)** | (295) | **—** | — | **—** | — |
| Remarketed gas – Net | **128** | 53 | **—** | — | **—** | — |
| Transmission charges and other expenses | **109** | 94 | **—** | — | **—** | — |
| Allocation from (to) domestic energy | **84** | (32) | **2,348** | (752) | **33.02** | 40.84 |
| Total Trade Cost of Energy Before Regulatory Transfers | **452** | 216 | **29,392** | 22,703 | **20.68** | 24.43 |
| Trade net margin regulatory transfers | **13** | (64) | **—** | — | — | — |
| **Total Trade** | **$ 465** | $ 152 | **29,392** | 22,703 | **$ 21.13** | $ 21.62 |
| **Total Energy Costs** | **$ 981** | $ 651 | **55,204** | 47,669 | **$ 20.60** | $ 20.76 |

[1] *Total GWh is net of storage exchange.*

[2] *Total GWh for transmission charges and other expenses relate only to non-integrated costs.*

[3] *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.*

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

[5] *Trade revenue regulatory transfer is netted with the trade cost of energy transfer to reflect a trade margin transfer.*

Total energy costs, after regulatory account transfers, for the three months ended September 30, 2011 were $564 million, $298 million or 112 per cent higher than the same period last year. For the six months ended September 30, 2011, total energy costs, after regulatory account transfers, were $981 million, $330 million or 51 per cent higher than in the same period last year. The increase in both the quarter and six month periods was primarily due to higher trade energy purchase costs due to higher gas and electricity purchase volumes and higher domestic energy costs mainly as a result of higher planned purchases for future trade.

## DOMESTIC ENERGY COSTS

Domestic energy costs before regulatory transfers of $229 million for the three months ended September 30, 2011 were $119 million or 34 per cent lower than in the same period in the prior year. For the six months ended September 30, 2011, domestic energy costs before regulatory transfers of $472 million were $164 million or 26 per cent lower than in the same period in the prior year. The decrease in both periods, as compared to the same periods in the prior year, was mainly a result of lower market energy purchases and lower purchases for future trade as higher water inflows reduced the need to buy energy to meet domestic load requirements. Higher water rental costs in both periods reflected the higher generation levels resulting from the higher water inflows this year. Higher purchases from Independent Power Producers (IPPs) were due to new IPPs becoming operational in the current fiscal year, partially offset by lower gas costs from Island Cogeneration purchases. Lower transmission charges for the six month period reflect the integration of the British Columbia Transmission Corporation (BCTC) with BC Hydro in the second quarter of fiscal 2011. Transmission costs recognized by BC Hydro as cost of energy in the first quarter of fiscal 2011, when the two companies were separate entities, were reclassified as other operating costs in the current year as a result of the inclusion of transmission activities in BC Hydro's operations. Variances between actual and planned domestic cost of energy are transferred to the HDA and Non-Heritage Deferral Account (NHDA).

## TRADE ENERGY COSTS

Gross trade energy costs for the three and six months ended September 30, 2011 were $512 million and $985 million, respectively, an increase of $61 million and $135 million over the comparable periods in the prior year. The increase for the three and six month periods ended September 30, 2011 was primarily due to an increase in the allocation from domestic energy of $83 million and $116 million, respectively, an increase in gas purchase costs of $53 million and $157 million, respectively, partially offset by a decrease in electricity purchased for trade of $91 million and $153 million, respectively. The increase in gross gas purchase costs was due to a 59 per cent and 46 per cent increase in purchase volumes for the three and six months ended September 30, 2011, respectively, consistent with higher sales volumes, partially offset by an 18 per cent and 32 per cent decrease, respectively, in the average gas purchase price. Electricity purchased for trade decreased in the three and six months ended September 30, 2011 primarily due to a decrease in the average electricity purchase price of 28 per cent and 32 per cent, respectively. The decrease in the average electricity purchase price was primarily due to lower Pacific Northwest prices as a result of higher water levels in the current fiscal year. Deducted from gross trade energy costs are forward purchases, which decreased by a net $191 million and $101 million for the three and six month period ended September 30, 2011, compared to the same periods in the prior year. Forward purchases are netted against forward sales within gross revenue in accordance with GAAP. Variances between actual and planned trade energy costs are deferred to the TIDA.

## WATER INFLOWS

System wide inflows into BC Hydro's reservoirs in the second quarter of fiscal 2012 were 14 per cent above average (average from 1971-2000). Based on the September 2011 energy study, fiscal 2012 is forecast to be about 107 per cent of average. There is negligible risk of spill at Williston and Kinbasket reservoirs for the balance of the fiscal year.

The BC Hydro reservoirs have been managed such that the combined storage in BC Hydro reservoirs at September 30, 2011 was 113 per cent of average (average 1986-2011), compared to 94 per cent of average at September 30, 2010, with the Williston reservoir on the Peace River system at 111 per cent of average, and the Kinbasket reservoir on the Columbia River system at 119 per cent of average.

## PERSONNEL EXPENSES

Personnel expenses include labour, benefits and employee future benefits. Personnel costs, after net regulatory transfers, of $139 million for the three months ended September 30, 2011 were comparable to the same period in the prior year. During the second quarter, workforce reductions of approximately 300 positions were planned for, and the reductions occurred in October. As a result, second quarter results include a severance accrual of $9.5 million which was offset by other favourable operational cost variances compared to the prior year. For the six months ended September 30, 2011 personnel costs of $289 million were $18 million higher than in the same period in the prior year primarily due to expenditures in the current year for transmission activities included in BC Hydro's operations which were part of BCTC in the first quarter of fiscal 2011, higher non-current pension costs and the severance accrual.

### MATERIALS AND EXTERNAL SERVICES

Materials and external services include expenditures for operating and maintenance materials and services provided by third parties. Expenditures on materials and external services, after net regulatory transfers, of $142 million and $286 million for the three and six month periods ended September 30, 2011, respectively, were comparable to the same periods in the prior year.

### CAPITALIZED COSTS

Capitalized costs are overhead costs incurred to support capital expenditures and are transferred from operating costs to property, plant and equipment. Capitalized costs for the three and six months ended September 30, 2011 were $75 million and $140 million respectively, compared to $76 million and $125 million for the same periods in the prior year and were in line with increases in capital expenditures as compared to the prior year.

### AMORTIZATION AND DEPRECIATION

Amortization and depreciation expense includes the depreciation of property, plant and equipment, intangible assets, asset retirement obligation (ARO) assets, amortization of customer contributions and the amortization of certain regulatory assets and liabilities. For the three and six month periods ended September 30, 2011, amortization and depreciation expense was $148 million and $328 million, respectively, compared with $128 million and $251 million in the same periods in the prior year. The increases were primarily due to higher assets in service as a result of BC Hydro's capital expenditure program and higher net regulatory account amortization resulting from the accelerated amortization of the Net Employment Cost and Total Finance Charges regulatory liability account balances in fiscal 2011 which significantly reduced net amortization expense in that fiscal year. Partially offsetting these increases was lower amortization of energy deferral accounts. In addition, as applied for in the Amended RRA, the quarter and year to date amortization expense reflect a proposed reduction in amortization of the Demand-Side Management (DSM) regulatory account resulting from an increase in depreciable life from 10 to 15 years, together with the cumulative year to date amortization of the fiscal 2012 opening balances of the Total Finance Charges, Taxes and Amortization of Capital Additions regulatory liability accounts.

### GRANTS AND TAXES

As a Crown Corporation, BC Hydro is exempt from paying federal and provincial income taxes, but pays local government taxes and grants in lieu to municipalities and regional districts. Total grants, school taxes and other local taxes of $45 million and $91 million for the three and six month periods ended September 30, 2011, respectively, were comparable to the same periods in the prior year.

## FINANCE CHARGES

Finance charges, after net regulatory transfers, for the three and six month periods ended September 30, 2011 of $119 million and $242 million, respectively, were $8 million and $25 million higher than in the same periods in the prior year. The increase in both periods is primarily due to higher planned volume of long-term debt issues primarily required to fund capital additions, lower planned foreign exchange gains, higher planned interest rates, lower planned capitalized interest, and higher planned capital lease financing costs.

## REGULATORY TRANSFERS

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

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

Regulatory transfers are comprised of the following:

| | *For the three months ended September 30* | | *For the six months ended September 30* | |
|---|---|---|---|---|
| *(in millions)* | **2011** | 2010 | **2011** | 2010 |
| Variances between forecast and actual costs | | | | |
| Energy deferral accounts | **$ (16)** | $ 142 | **$ (51)** | $ 223 |
| Finance charges | **(12)** | (3) | **(16)** | (16) |
| Other | **5** | (13) | **(2)** | (11) |
| | **(23)** | 126 | **(69)** | 196 |
| Deferral of costs for future recovery in rates | | | | |
| Demand-Side Management | **36** | 25 | **64** | 50 |
| Rate Smoothing | **(54)** | — | **(19)** | — |
| Site C | **24** | 11 | **42** | 17 |
| Environmental Compliance | **(29)** | 3 | **(27)** | 6 |
| Other | **22** | 11 | **43** | 25 |
| | **(1)** | 50 | **103** | 98 |
| Amortization of regulatory accounts | **(13)** | 4 | **(58)** | 5 |
| Interest on regulatory accounts | **13** | 10 | **25** | 17 |
| **Net change in regulatory accounts** | **$ (24)** | $ 190 | **$ 1** | $ 316 |

For the three months ended September 30, 2011, the net reduction after amortization of BC Hydro's regulatory accounts was $24 million, compared with net additions of $190 million to the regulatory accounts during the same period last year. For the six months ended September 30, 2011, net additions after amortization of BC Hydro's regulatory accounts was $1 million compared with net additions of $316 million during the same period in the prior year. The net asset balance in the regulatory asset and liability accounts as at September 30, 2011 was an asset of $2,161 million compared to $2,160 million at March 31, 2011.

The transfers from the energy deferral accounts in the current fiscal year primarily reflect higher than planned trade income resulting from favourable price spreads in the Northwest and Alberta, and lower than planned domestic cost of energy as a result of high water inflows which reduced the requirement for market energy purchases and purchases for future trade, and IPP purchases made at lower than planned prices. In the second quarter, transfers from the NHDA reflect a change in the planned rate increase for fiscal 2012 to 8 per cent from 9.73 per cent as per the Amended RRA. In comparison, energy deferral account transfers for the same periods in fiscal 2011 reflected higher than planned domestic energy costs resulting from low water inflows and lower than planned trade income due to low price spreads.

Other significant regulatory transfers include transfers from the Total Finance Charges regulatory account reflecting lower than planned costs mainly due to lower than planned levels of debt as a result of lower than planned capital expenditures. Transfers from the Rate Smoothing Regulatory Account, which has been applied for to smooth the rate increases applied for in BC Hydro's F2012–F2014 RRA over the three year period covered by the application, were adjusted in the second quarter to reflect the cumulative impact of the Amended RRA. This regulatory account remains subject to approval by the BCUC. The Environmental Compliance regulatory account was adjusted in the second quarter due to new guidelines issued by Environment Canada during the period which resulted in a $30 million reduction to BC Hydro's provision for PCB remediation. Expenditures on the Site C project reflect the increase in costs associated with environmental assessment activities being undertaken in the current fiscal year, and expenditures on DSM projects, which support energy conservation, were slightly higher than in the same periods in the prior year. The change in amortization of regulatory accounts primarily reflects the accelerated amortization of certain regulatory liability account balances in fiscal 2011 which significantly reduced net regulatory account amortization in that fiscal year.

## FUTURE ACCOUNTING CHANGE

### International Financial Reporting Standards

The *Budget Transparency and Accountability Act* (BTAA) specifies that the Government and government organizations conform to the set of standards and guidelines that comprise generally accepted accounting principles for senior governments in Canada, unless otherwise directed by Treasury Board. Accounting standards for senior government are understood to mean standards established by the Public Sector Accounting Board (PSAB), which directs Government Business Enterprises (GBE) to adhere to International Financial Reporting Standards (IFRS). BC Hydro is classified as a GBE. In 2010, the Canadian Accounting Standards Board (AcSB) issued guidance allowing qualifying entities with rate-regulated activities be permitted, but not required, to continue applying the accounting standards in Part V of the CICA Handbook—*Accounting* for an additional year rather than adopting IFRS for annual periods beginning on or after January 1, 2011. BC Hydro is applying the deferral option.

Subsequent to the expiration of the deferral period, BC Hydro will adopt financial reporting provisions prescribed by the Province pursuant to Section 23.1 of the BTAA and Section 9.1 of the *Financial Administration Act* (FAA). BC Hydro will prepare its consolidated financial statements in accordance with IFRS, except that in accordance with legislation, it will continue to apply regulatory accounting in accordance with the United States Financial Accounting Standards Board Accounting Standards Codification 980 (ASC 980), *Regulated Operations*. The application of ASC 980 results in BC Hydro recognizing in the statement of financial position the deferral and amortization of certain costs and recoveries that have been approved by the BCUC for inclusion in future customer rates. In accordance with IFRS, such costs and recoveries would otherwise be included in the determination of comprehensive income in the year the amounts are incurred.

## 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. No dividend has been accrued as at September 30, 2011 for fiscal 2012 as BC Hydro's debt to equity ratio is over the 80:20 cap before any dividend accrual.

Effective April 1, 2011, Order in Council (OIC) No. 021 amended Heritage Special Directive No. HC1 by changing the definition of distributable surplus used in the calculation of the Payment to mean the consolidated net income earned by BC Hydro and its subsidiaries from all sources as reflected in the consolidated audited financial statements, as compared to the previous definition in which net capitalized finance charges were deducted from consolidated net income.

## LEGAL PROCEEDINGS

Since 2000, Powerex has been named, along with other energy providers, in lawsuits and U.S. federal regulatory proceedings which seek damages and/or contract rescissions based on allegations that, during part of 2000 and 2001, the California wholesale electricity markets were unlawfully manipulated and energy prices were not just and reasonable. At September 30, 2011, Powerex was owed US $265 million (CDN $275 million) by the California Power Exchange and the California Independent System Operator related to Powerex's trade activities in California during the period covered by the lawsuits. It is expected those receivables will be offset against any refunds that Powerex is required to pay.

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

## REGULATION

In the process of regulating and setting rates for BC Hydro, the BCUC must ensure that the rates are sufficient to allow BC Hydro to provide reliable electricity service, meet its financial obligations, comply with government policy and achieve a certain return on equity (ROE). The annual rate of ROE is equal to the pre-income tax annual rate of return allowed by the BCUC to the most comparable investor-owned energy utility regulated under the *Utilities Commission Act*. This is in accordance with Heritage Special Direction No. HC2. OIC No. 074 dated February 17, 2009 amended Heritage Special Direction No. HC2 to allow for an addition of 1.63 per cent to the ROE in fiscal years 2010, 2011 and 2012. The allowed rate of ROE for fiscal 2012 is 14.38 per cent, and is higher than the prior year's allowed rate of 14.37 per cent due to the higher rate of return allowed for FortisBC Energy Inc. (formerly Terasen Gas Inc.), upon which BC Hydro's return on equity is based.

OIC No. 020 dated February 2, 2011, and effective April 1, 2011, amended Heritage Special Direction No. HC2, such that BC Hydro's return on equity will be based on total assets in service, changed from total debt and equity. Equity for rate-setting purposes (Deemed Equity) is now 30 per cent of BC Hydro's rate base, which is comprised of a working capital allowance, assets in service (excluding leased assets), and DSM expenditures less contributions in aid of construction and Columbia River Treaty contributions. From fiscal 2009 to fiscal 2011, Deemed Equity was equal to 30 per cent of the sum of BC Hydro's average debt and average equity balances for the year. The F2012–F2014 RRA and Amended RRA incorporate the changes to the return on equity calculation.

### F2012–F2014 RRA

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

In April 2011, the BCUC approved an average interim rate increase for fiscal 2012 of 8 per cent effective May 1, 2011 and suspended the regulatory process for reviewing the F2012–F2014 RRA until the completion of a provincial government review of BC Hydro. Following this review, BC Hydro amended its application to reduce its proposed rate increase to 8 per cent in fiscal 2012 and a 3.9 per cent increase in each of fiscal 2103 and fiscal 2014. The Amended RRA was filed with the BCUC on November 24, 2011 and included the DSM Expenditure filing requesting acceptance of planned DSM expenditures for fiscal 2012 and fiscal 2013. An initial regulatory schedule has been established for review of the amended application which will have BC Hydro responding to the first round of Information Requests from the BCUC and interveners on January 31, 2012.

The Amended RRA reflects an updated net income forecast for fiscal 2012 of $595 million, compared to a net income forecast of $611 million in the original March 2011 F2012–F2014 RRA filing due to a reduction in the return on equity calculation. The impact of the Amended RRA on financial results for the three and six months ended September 30, 2011 was a reduction in net income of $5 million.

### Interior to Lower Mainland Transmission (ILM) Project

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

The BCUC issued its decision on February 3, 2011, finding that the Crown's duty to consult with certain First Nations had not been adequately met as of August 5, 2008, and as result, continuing the suspension of the ILM CPCN. BC Hydro was directed to conduct further consultation with these First Nations and report back to the BCUC. On September 29, 2011, in its reconsideration decision, the BCUC determined that the further consultation undertaken by BC Hydro was adequate and lifted the suspension of the ILM CPCN.

Those First Nations whom the BCUC deemed had been adequately consulted with filed an application to the BCUC on March 2, 2011 seeking reconsideration of the BCUC decision. The BCUC dismissed this application on May 6, 2011 on the basis that it did not meet their threshold for a reconsideration to progress. However, on June 27, 2011, the Court of Appeal granted leave to these First Nations to appeal the BCUC reconsideration decision. On August 26, 2011, the First Nations withdrew their intervention in the Court of Appeal process and consented to the issuance of the ILM CPCN.

### Ruskin Dam Upgrade Project

On February 22, 2011, BC Hydro filed an application for a CPCN for the Ruskin Dam Upgrade Project. This project involves replacing parts of the seismically deficient dam, and rehabilitating or replacing the powerhouse, including generating equipment and associated transmission facilities. A written hearing process for reviewing this application has been extended to accommodate the filing of First Nations evidence and will now conclude in late December 2011. A decision is likely in early 2012.

### Dawson Creek/Chetwynd Area Transmission Upgrade Project

On July 11, 2011, BC Hydro filed an application with the BCUC for a CPCN for the Dawson Creek/Chetwynd Area Transmission Upgrade Project. This project proposes to address electricity supply constraints in the southern Peace region of the province and meet significant forecasted load growth in that region attributable to the development of the Montney natural gas play. The project involves the construction of a new substation, a new 230 kV transmission line and the expansion of an existing substation at an estimated cost of $250 million. If approved by the BCUC, the project is expected to be in service by October 2013. A written Information Request process is underway and a procedural conference was held by the BCUC on November 4, 2011 to establish the rest of the review process.

## LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the second quarter was $238 million, compared with cash flow provided by operating activities of $40 million for the same period last year. For the six months ended September 30, 2011, cash flow provided by operating activities was $306 million, compared with cash flow provided by operating activities of $153 million in the same period last year. The increase in both periods was primarily due to changes in working capital relative to the same periods in the prior year, mainly as a result of increased collections of accounts receivable, and changes in regulatory account transfers, partially offset by lower net income.

The long-term debt balance net of sinking funds at September 30, 2011 was $12.5 billion, compared with $11.5 billion at March 31, 2011. The increase was mainly a result of net long-term bond issues totaling $1,040 million ($1.1 billion par value) and net foreign exchange revaluation losses on bonds and sinking funds of $74 million. This increase was partially offset by a decrease in revolving borrowings of $99 million, a decrease of $3 million in debt due to fair value hedge accounting, amortization of premiums of $3 million and sinking fund income of $3 million. The net increase in borrowings was primarily due to the funding of capital expenditures.

## PROPERTY, PLANT AND EQUIPMENT EXPENDITURES

Property, plant and equipment expenditures were as follows:

| | *For the three months ended September 30* | | *For the six months ended September 30* | |
|---|---|---|---|---|
| | | *(Revised)* | | *(Revised)* |
| *(in millions)* | **2011** | 2010 | **2011** | 2010 |
| Distribution improvements and expansion | **$ 107** | $ 127 | **$ 200** | $ 215 |
| Generation replacements and expansion | **134** | 97 | **251** | 192 |
| Transmission lines and substation replacements and expansion | **154** | 137 | **259** | 221 |
| General, including computers, vehicles and land rights | **92** | 58 | **174** | 108 |
| | **$ 487** | $ 419 | **$ 884** | $ 736 |

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

Distribution capital expenditures were $20 million lower in the second quarter and $15 million year to date compared with the same periods in the prior year. The decrease for the quarter and year to date is mainly due to delays in System Expansion and Improvements approval and design work in fiscal 2012 and higher System Resiliency (SR) plan and scheduling difference of SR work in fiscal 2011. Also contributing to the decrease year to date are lower expenditures on the End of Life Cut-Out Program and lower volume and costs in Distribution Poles.

Generation capital expenditures increased by $37 million in the second quarter and $59 million year to date compared with the same periods in the prior year. The increase for the quarter and year to date is mainly due to the higher spending on the Fort Nelson Resource Smart Upgrade, Mica Units 5 & 6 installations; partially offset by lower spending on the Mica Gas Insulated Switchgear Replacement. Also contributing to the increase year to date is higher spending on the Bridge River Townsite Redevelopment; partially offset by lower spending on the Revelstoke Unit 5 Installation, as it was placed in service in the third quarter of fiscal 2011.

Transmission lines and substations capital expenditures increased by $17 million in the second quarter and $38 million year to date compared with the same periods in the prior year. The increase is mainly due to higher spending in fiscal 2012 on the Northwest Transmission Line project, Vancouver City Central Transmission project, Columbia Valley Transmission project and the Interior to Lower Mainland project; partially offset by lower spending on the Central Vancouver Island project, the Saanich Peninsula project and the 500/230 kV Selkirk Transformer T4 Addition which were substantially complete at the end of fiscal 2011.

General capital expenditures increased by $34 million in the second quarter and $66 million year to date compared with the same periods in the prior year. The increase for the quarter and year to date is mainly due to higher spending on the Smart Metering and Infrastructure Program, as it is in the implementation phase in fiscal 2012 with the installation of meters, telecom and IT infrastructure all in progress; partially offset by the Horne Payne construction project completed in the second quarter of fiscal 2011. Also contributing to the offset year to date is the purchase of the Edmonds Annex Building in the first quarter of fiscal 2011.

## RISK MANAGEMENT

BC Hydro faces risks to its business that could significantly impact its ability to achieve its short and long-term financial, social and environmental goals. The goal of risk management is not to eliminate risks, but rather to mitigate them to levels which are commensurate with the potential benefits to be derived. Similarly, BC Hydro's risk management strategies aim to mitigate risks through a consistent risk management process that is applied to day-to-day business activities as well as to specific projects and initiatives. BC Hydro's Chief Risk Officer is responsible for facilitating this risk management process and promoting strong oversight of significant risks by the BC Hydro Risk Management Committee. BC Hydro's Board of Directors also plays a key role in the oversight of risk management, as the Board must understand the risks being taken by BC Hydro and ensure that processes are in place to appropriately manage the risks. BC Hydro's operations involve a broad spectrum of risks ranging from those commonly associated with any business to catastrophic societal loss risks that would have severe effects on entire regions.

There were no changes in significant risks to BC Hydro's business during the six months ended September 30, 2011 from those discussed in the Management Discussion and Analysis presented in the Annual Report for the year ended March 31, 2011, with the exception of system inflows. System inflows, market prices, and domestic load influence cost of energy. The system inflow energy for fiscal 2012 is now expected to be 7 per cent above normal and the system is forecast to be in a modest net sales position for fiscal 2012.

## FUTURE OUTLOOK

The *Budget Transparency and Accountability Act* requires that BC Hydro file a Service Plan each year. BC Hydro's Service Plan forecast a net income of $611 million for fiscal 2012.

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 updated forecast for fiscal 2012 assumes average water inflows (100 per cent of average), customer load of 52,919 GWh, average market electricity prices of US $28.69/MWh, short-term interest rates of 0.97 per cent and a U.S. dollar exchange rate of U.S. $0.9943.

BC Hydro filed its Amended RRA in late November 2011 that reflected the outcome of the Government Review and updated other assumptions in the normal course of a net income forecast update such as interest rates and water inflow levels. The Amended RRA seeks rate increases of 8 per cent, 3.9 per cent and 3.9 per cent for fiscal 2012 to fiscal 2014, respectively. The reduction from the 9.73 per cent increase per year from the Service Plan will be achieved through a combination of reductions in operating costs and capital additions, lower finance charges, increased trade income forecast, deferral of work programs to future years, and changes in regulatory account amortization.

The updated net income forecast for fiscal 2012 is $595 million. The significant changes from the Service Plan for fiscal 2012 include:

- A reduction in capital additions and operating costs through a deferral of work programs and accelerating the pace of efficiencies.
- Lower net income largely from lower assets in service at the end of fiscal 2011. As a result deemed equity (30 per cent of rate base which includes assets in service) is reduced and there is a corresponding decrease in the allowed return on equity.
- An increase in forecast Trade Income due to favourable market opportunities in the first half of this fiscal year.
- Customer sales load of 52,919 GWh, an increase of 848 GWh from the Service Plan. This increase is mainly due to higher load in the large industrial and commercial sectors.
- An increase in the forecast cost of energy resulting mainly from higher domestic sales load and increased IPP purchases. IPP purchases have increased due mainly to an increase in surplus energy deliveries from Rio Tinto Alcan under an existing agreement.
- The impact of the domestic revenue and energy cost variances from the Service Plan is proposed to be deferred in the energy deferral regulatory accounts for future recovery/refund through rates and therefore is expected to have no impact on net income in fiscal 2012.

# INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) SEPTEMBER 30, 2011

## CONSOLIDATED STATEMENTS OF OPERATIONS

| *(unaudited)* | *For the three months ended September 30* | | *For the six months ended September 30* | |
|---|---|---|---|---|
| | | *(Revised Note 1)* | | *(Revised Note 1)* |
| *(in millions)* | **2011** | 2010 | **2011** | 2010 |
| **Revenues** | | | | |
| Domestic | **$ 748** | $ 767 | **$ 1,634** | $ 1,552 |
| Trade | **404** | 106 | **599** | 293 |
| | **1,152** | 873 | **2,233** | 1,845 |
| **Expenses** | | | | |
| Operating Costs | | | | |
| Cost of energy (Note 9) | **564** | 266 | **981** | 651 |
| Other operating costs (Note 9) | **406** | 377 | **855** | 767 |
| | **970** | 643 | **1,836** | 1,418 |
| Finance Charges | **119** | 111 | **242** | 217 |
| | **1,089** | 754 | **2,078** | 1,635 |
| **Net Income** | **$ 63** | $ 119 | **$ 155** | $ 210 |

*See accompanying notes to the interim consolidated financial statements.*

## CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| *(unaudited)* | *For the three months ended September 30* | | *For the six months ended September 30* | |
|---|---|---|---|---|
| *(in millions)* | **2011** | 2010 | **2011** | 2010 |
| Net Income | **$ 63** | $ 119 | **$ 155** | $ 210 |
| Other Comprehensive (Loss) Income (Note 8) | **(9)** | 5 | **(12)** | (13) |
| **Comprehensive Income** | **$ 54** | $ 124 | **$ 143** | $ 197 |

*See accompanying notes to the interim consolidated financial statements.*

## CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

| *(unaudited)* | *For the six months ended September 30* | |
|---|---|---|
| *(in millions)* | **2011** | 2010 |
| Retained Earnings, Beginning of Period | **$ 2,747** | $ 2,621 |
| Net Income | **155** | 210 |
| Accrued Payment to the Province (Note 6) | **—** | (70) |
| **Retained Earnings, End of Period** | **$ 2,902** | $ 2,761 |

*See accompanying notes to the interim consolidated financial statements.*

# CONSOLIDATED BALANCE SHEETS

| *(unaudited)*<br>*(in millions)* | *As at September 30 2011* | *As at March 31 2011* |
|---|---|---|
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | **$ 5** | $ 27 |
| Accounts receivable and accrued revenue | **489** | 569 |
| Inventories | **167** | 128 |
| Prepaid expenses | **217** | 156 |
| Current portion of derivative financial instrument assets | **161** | 198 |
| | **1,039** | 1,078 |
| **Other Assets** | | |
| Property, plant and equipment | **15,754** | 15,211 |
| Intangible assets | **362** | 335 |
| Regulatory assets (Note 4) | **2,446** | 2,436 |
| Sinking funds | **106** | 97 |
| Employee future benefits | **284** | 296 |
| Derivative financial instrument assets | **42** | 26 |
| | **18,994** | 18,401 |
| | **$ 20,033** | $ 19,479 |
| **LIABILITIES AND EQUITY** | | |
| **Current Liabilities** | | |
| Accounts payable and accrued liabilities | **$ 1,008** | $ 1,515 |
| Current portion of long-term debt | **2,688** | 2,793 |
| Current portion of derivative financial instrument liabilities | **115** | 159 |
| | **3,811** | 4,467 |
| **Other Liabilities** | | |
| Long-term debt (Note 5) | **9,971** | 8,851 |
| Regulatory liabilities (Note 4) | **285** | 276 |
| Deferred contributions | **1,071** | 1,012 |
| Derivative financial instrument liabilities, long-term | **162** | 212 |
| Other long-term liabilities | **1,710** | 1,781 |
| | **13,199** | 12,132 |
| **Shareholder's Equity** | | |
| Contributed surplus | **60** | 60 |
| Retained earnings | **2,902** | 2,747 |
| Accumulated other comprehensive income (Note 8) | **61** | 73 |
| | **3,023** | 2,880 |
| | **$ 20,033** | $ 19,479 |

**Commitments and Contingencies** (Note 10)

*See accompanying notes to the interim consolidated financial statements.*

**Approved on behalf of the Board:**

Dan Doyle
Chairman

Tracey L. McVicar
Chair, Audit & Finance Committee

# CONSOLIDATED STATEMENTS OF CASH FLOWS

| *(unaudited)* | *For the three months ended September 30* | | *For the six months ended September 30* | |
|---|---|---|---|---|
| *(in millions)* | **2011** | 2010 | **2011** | 2010 |
| **Operating Activities** | | | | |
| Net income | **$ 63** | $ 119 | **$ 155** | $ 210 |
| Regulatory account transfers | **(55)** | (183) | **(123)** | (303) |
| Adjustments for non-cash items: | | | | |
| Amortization of regulatory accounts (Note 4) | **13** | (4) | **58** | (5) |
| Amortization expense and depreciation | **141** | 124 | **281** | 233 |
| Foreign exchange translation (gains) losses | **10** | (4) | **9** | 2 |
| Unrealized gains on mark-to-market | **(18)** | (35) | **(18)** | (65) |
| Employee benefit plan expenses | **15** | 12 | **31** | 24 |
| Other items | **(2)** | (1) | **(5)** | 8 |
| | **167** | 28 | **388** | 104 |
| Changes in non-cash working capital: | | | | |
| Accounts receivable and accrued revenue | **79** | 182 | **80** | 253 |
| Accounts payable and accrued liabilities | **29** | (79) | **(62)** | (107) |
| Prepaid expenses | **(21)** | (92) | **(61)** | (53) |
| Inventories | **(16)** | 1 | **(39)** | (44) |
| | **71** | 12 | **(82)** | 49 |
| **Cash provided by operating activities** | **238** | 40 | **306** | 153 |
| **Investing Activities** | | | | |
| Property, plant and equipment and intangible asset expenditures | **(457)** | (418) | **(869)** | (785) |
| Deferred contributions | **47** | 25 | **74** | 37 |
| Other items | **(2)** | (1) | **2** | (2) |
| **Cash used in investing activities** | **(412)** | (394) | **(793)** | (750) |
| **Financing Activities** | | | | |
| Long-term debt: | | | | |
| Issued | **61** | 593 | **1,048** | 593 |
| Retired | **—** | (150) | **—** | (150) |
| Revolving borrowings, included in long-term debt | **118** | (116) | **(100)** | 211 |
| Debt issue and related costs | **(1)** | — | **(8)** | — |
| Payment to the Province | **—** | — | **(463)** | (47) |
| Repayment of capital lease liability | **(6)** | — | **(12)** | — |
| **Cash provided by financing activities** | **172** | 327 | **465** | 607 |
| **(Decrease) increase in cash and cash equivalents** | **(2)** | (27) | **(22)** | 10 |
| **Cash and cash equivalents, beginning of period** | **7** | 46 | **27** | 9 |
| **Cash and cash equivalents, end of period** | **$ 5** | $ 19 | **$ 5** | $ 19 |
| **Supplemental Disclosure of Cash Flow Information** | | | | |
| Interest paid | **$ 108** | $ 110 | **$ 297** | $ 278 |
| Non-cash transaction: | | | | |
| Capital lease obligation included in other liabilities | **$ —** | $ — | **$ —** | $ 171 |

*See accompanying notes to the interim consolidated financial statements.*

# NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) SEPTEMBER 30, 2011

## DESCRIPTION

British Columbia Hydro and Power Authority (BC Hydro or the Company) 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, conserve and supply power.

## NOTE 1: BASIS OF PRESENTATION

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. 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 2011 Annual Report. These interim consolidated financial statements follow the same accounting policies as those described in BC Hydro's 2011 Annual Report. Certain amounts in the prior period statements related to revenues, cost of energy, and finance charges have been reclassified to conform to the current year's presentation.

BC Hydro is subject to regulation by the British Columbia Utilities Commission (BCUC) which, among other things, approves the rates BC Hydro charges for its services. 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 (see Note 4).

### Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets, liabilities and commitments at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Significant items subject to management estimates and assumptions include the determination of the allowance for doubtful accounts, the fair value of sinking funds and derivative and non-derivative financial instruments, the actuarial assumptions used to value the employee future benefit plans, the useful lives of property, plant and equipment and intangible assets, amounts for accrued liabilities and contingencies including environmental, legal, First Nations, asset retirement and lease obligations, the accrual for unbilled revenue at period end, the estimated net realizable value of inventory, and regulatory assets and liabilities. Actual results could differ from these estimates.

## NOTE 2: ACCOUNTING CHANGES

Publicly accountable enterprises in Canada were required to adopt International Financial Reporting Standards (IFRS) for fiscal years beginning on or after January 1, 2011. However, qualifying entities with rate-regulated activities were granted an optional one-year deferral for the adoption of IFRS due to the uncertainty around the timing and adoption of a potential rate-regulated accounting standard by the International Accounting Standards Board. As a qualifying entity with rate-regulated activities, BC Hydro has elected to opt for the one-year deferral and therefore will continue to prepare its consolidated financial statements in accordance with Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook for all interim and annual periods ending on or before March 31, 2012.

Subsequent to the one-year deferral for adopting IFRS, BC Hydro will adopt financial reporting provisions prescribed by the Province. In accordance with a regulation issued by the Province's Treasury Board, BC Hydro will prepare its consolidated financial statements in accordance with IFRS, except that it will continue to apply regulatory accounting in accordance with the United States Financial Accounting Standards Board Accounting Standards Codification 980 (ASC 980), *Regulated Operations*. The application of ASC 980 results in BC Hydro recognizing in the statement of financial position the deferral and amortization of certain costs and recoveries that have been approved by the BCUC for inclusion in future customer rates. In accordance with IFRS, such costs and recoveries would otherwise be included in the determination of comprehensive income in the year the amounts are incurred.

## 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. Revenue requirements and rates charged to customers are established through applications filed with and approved by the BCUC.

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

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

On April 21, 2011, the BCUC approved an average interim rate increase for fiscal 2012 of 8 per cent effective May 1, 2011 and suspended the regulatory process for reviewing the F2012-F2014 RRA until the completion of a provincial government review of BC Hydro. Following this review, BC Hydro amended its revenue requirements application to reduce its proposed rate increases to 8 per cent in F2012 and 3.9 per cent increase in each of F2013 and F2014. The amended F2012-F2014 RRA (Amended RRA) was filed with the BCUC on November 24, 2011.

### Regulatory Accounts

The following regulatory assets and liabilities have been established through rate regulation. For the three and six months ended September 30, 2011, the impact of regulatory accounting has resulted in a decrease of $24 million and increase to net income of $1 million (three and six months ended September 30, 2010—$190 million and $316 million increase, respectively).

Transfers to regulatory accounts between actual and planned revenues and expenses are based on the Amended RRA. As a result, the Non-Heritage, trade income, and finance charge regulatory account transfers reflect the cumulative year to date impact of the Amended RRA plan. In addition, regulatory account amortization reflects adjustments to the amortization in the current year of the DSM, Taxes, Finance Charges and Amortization of Capital Additions regulatory accounts. The impact to net income due to the Amended RRA for the three and six months period ended September 30, 2011 was a $5 million decrease.

| *(in millions)* | *April 1 2011* | *Addition (Reduction)* | *Amortization* | *Net Change* | *September 30 2011* |
|---|---|---|---|---|---|
| **Regulatory Assets** | | | | | |
| Heritage Deferral Account | $ 247 | $ (18) | $ (12) | $ (30) | $ 217 |
| Non-Heritage Deferral Account | 362 | 7 | (17) | (10) | 352 |
| Trade Income Deferral Account | 188 | (20) | (9) | (29) | 159 |
| Demand-Side Management Programs | 506 | 64 | (20) | 44 | 550 |
| First Nation Negotiations, Litigation and Settlement Costs | 399 | 9 | (3) | 6 | 405 |
| Non-Current Pension Cost | 72 | (5) | (9) | (14) | 58 |
| Site C | 104 | 44 | — | 44 | 148 |
| CIA Amortization Variance | 59 | 4 | — | 4 | 63 |
| Environmental Compliance | 231 | (27) | (2) | (29) | 202 |
| Other Regulatory Accounts | 268 | 34 | (10) | 24 | 292 |
| **Total Regulatory Assets** | 2,436 | 92 | (82) | 10 | 2,446 |
| **Regulatory Liabilities** | | | | | |
| Future Removal and Site Restoration Costs | 140 | — | (10) | (10) | 130 |
| Rate Base Smoothing | — | 19 | — | 19 | 19 |
| Foreign Exchange Gains and Losses | 106 | (9) | — | (9) | 97 |
| Finance Charges | 4 | 16 | (2) | 14 | 18 |
| Other Regulatory Accounts | 26 | 7 | (12) | (5) | 21 |
| **Total Regulatory Liabilities** | 276 | 33 | (24) | 9 | 285 |
| **Net Regulatory Asset** | $ 2,160 | $ 59 | $ (58) | $ 1 | $ 2,161 |

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. Order in Council 020 dated February 2, 2011, and effective April 1, 2011, amended Heritage Special Direction No. HC2, such that BC Hydro's return on equity is now based on total assets in service, changed from total debt and equity. Equity for rate-setting purposes (Deemed Equity) is now 30 per cent of BC Hydro's rate base, which is comprised of a working capital allowance, assets in service (excluding leased assets), and DSM expenditures; less contributions in aid of construction and Columbia River Treaty contributions. From fiscal 2009 to fiscal 2011, Deemed Equity was equal to 30 per cent of the sum of BC Hydro's average debt and average equity balances for the year. The F2012–F2014 RRA and Amended RRA incorporate the changes to the return on equity calculation.

In April 2011, the BCUC approved BC Hydro's application to establish the Rock Bay Environmental Remediation regulatory account which allows deferral of operating costs incurred in fiscal 2011, which were approximately $2 million.

BC Hydro received approval from the BCUC in May 2011 for the establishment of the Arrow Water Systems regulatory account to defer divestiture costs relating to the transfer of the Arrow Water Systems to the Regional District of Central Kootenay and for the loss provision liability in connection with the divestiture, which total $11 million at September 30, 2011.

In July 2011, BC Hydro received approval for deferral of fiscal 2011 costs for Smart Metering and Infrastructure Project Costs (SMI), which was $15 million (asset) as at March 31, 2011. BCHydro is requesting deferral of all net SMI costs for fiscal 2012 to 2014 in its F2012–F2014 RRA and Amended RRA applications.

BC Hydro applied for the establishment of the F2012–F2014 Rate Smoothing regulatory account in order to smooth out the rate increases proposed in the F2012–F2014 RRA, which was estimated to be $19 million (liability) as at September 30, 2011.

Other regulatory asset accounts with individual balances less than $65 million include the following: Contributions in Aid of Construction Amortization Variance, Capital Project Investigation Costs, Procurement Enhancement Initiative Costs, SMI, GM Shrum Unit 3 Outage, Home Purchase Option Program, Return on Equity (ROE) Adjustment, and Waneta Rate Smoothing.

Other regulatory liability accounts with individual balances less than $15 million include the following: Amortization of Capital Additions, Taxes, and Storm Damage.

## NOTE 5: LONG-TERM DEBT

In the three month period ended September 30, 2011, the Company issued bonds with a par value of $50 million, a weighted average effective interest rate of 3.77 per cent and a weighted average term to maturity of 36.7 years. For the six month period ended September 30, 2011, the Company issued bonds with a par value of $1.1 billion, a weighted average effective interest rate of 4.39 per cent and a weighted average term to maturity of 31.4 years. Debt issue costs associated with the transactions were $7 million.

## NOTE 6: CAPITAL MANAGEMENT

Orders in Council (OIC) from the Province establish the basis for determining BC Hydro's equity for regulatory purposes, as well as 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, the applicable OIC defines debt as revolving borrowings and interest-bearing borrowings less investments held in sinking funds and cash and cash equivalents. Equity as defined for regulatory purposes comprises retained earnings, accumulated other comprehensive income (loss) and contributed surplus.

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 at September 30, 2011 and March 31, 2011 was as follows:

| *(in millions)* | *As at September 30 2011* | *As at March 31 2010* |
|---|---|---|
| Total long-term debt, net of sinking funds | **$ 12,553** | $ 11,547 |
| Less: cash and cash equivalents | **(5)** | (27) |
| **Net Debt** | **$ 12,548** | $ 11,520 |
| | | |
| Retained earnings | **$ 2,902** | $ 2,747 |
| Contributed surplus | **60** | 60 |
| Accumulated other comprehensive income | **61** | 73 |
| **Total Equity** | **$ 3,023** | $ 2,880 |
| **Net Debt to Equity Ratio** | **81 : 19** | 80 : 20 |

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. No dividend has been accrued as at September 30, 2011, as BC Hydro's debt to equity ratio is over the 80:20 cap.

Effective April 1, 2011, OIC No. 021 amended Heritage Special Directive No. HC1 by changing the definition of distributable surplus used in the calculation of the Payment to mean the consolidated net income earned by BC Hydro and its subsidiaries from all sources as reflected in the audited consolidated financial statements, as compared to the previous definition in which net capitalized finance charges were deducted from consolidated net income.

## NOTE 7: EMPLOYEE FUTURE BENEFITS

BC Hydro's cost for employee future benefits for the three and six months ended September 30, 2011 was $31 million and $61 million (fiscal 2011—$26 million and $53 million).

## NOTE 8: OTHER COMPREHENSIVE INCOME (LOSS) & ACCUMULATED OTHER COMPREHENSIVE INCOME

### Other Comprehensive Income (Loss)

| *(in millions)* | *For the three months ended September 30* **2011** | 2010 | *For the six months ended September 30* **2011** | 2010 |
|---|---|---|---|---|
| **Other Comprehensive Income** | | | | |
| Unrealized gain (loss) on derivatives designated as cash flow hedges | **$ 64** | $ (26) | **$ 53** | $ — |
| Reclassification to income of loss (gain) on deriviatives designated as cash flow hedges | **(73)** | 31 | **(65)** | (13) |
| **Other Comprehensive (Loss) Income** | **$ (9)** | $ 5 | **$ (12)** | $ (13) |

### Accumulated Other Comprehensive Income

| *(in millions)* | *For the six months ended September 30* **2011** | 2010 |
|---|---|---|
| Accumulated other comprehensive income, beginning of period | **$ 73** | $ 53 |
| Other comprehensive loss for the period | **(12)** | (13) |
| **Accumulated Other Comprehensive Income, End of Period** | **$ 61** | $ 40 |

# NOTE 9: OPERATING COSTS

### Cost of Energy

| | For the three months ended September 30 | | For the six months ended September 30 | |
|---|---|---|---|---|
| *(in millions)* | **2011** | 2010 | **2011** | 2010 |
| Electricity and gas purchases | **$ 437** | $ 137 | **$ 753** | $ 376 |
| Water rentals | **83** | 82 | **154** | 153 |
| Transmission charges | **44** | 47 | **74** | 122 |
| **Cost of Energy** | **$ 564** | $ 266 | **$ 981** | $ 651 |

### Other Operating Costs

| | For the three months ended September 30 | | For the six months ended September 30 | |
|---|---|---|---|---|
| *(in millions)* | **2011** | 2010 | **2011** | 2010 |
| Personnel expenses | **$ 139** | $ 140 | **$ 289** | $ 271 |
| Materials and external services | **142** | 142 | **286** | 286 |
| Amortization and depreciation | **148** | 128 | **328** | 251 |
| Capitalized costs | **(75)** | (76) | **(140)** | (125) |
| Grants and taxes | **45** | 45 | **91** | 90 |
| Other costs | **7** | (2) | **1** | (6) |
| **Other Operating Costs** | **$ 406** | $ 377 | **$ 855** | $ 767 |

# NOTE 10: COMMITMENTS AND CONTINGENCIES

### Legal Proceedings

Since 2000, Powerex has been named, along with other energy providers, in lawsuits and U.S. federal regulatory proceedings which seek damages and/or contract rescissions based on allegations that, during part of 2000 and 2001, the California wholesale electricity markets were unlawfully manipulated and energy prices were not just and reasonable. At September 30, 2011, Powerex was owed US $265 million (CDN $275 million) by the California Power Exchange and the California Independent System Operator related to Powerex's trade activities in California during the period covered by the lawsuits. It is expected those receivables will be offset against any refunds that Powerex is required to pay.

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.

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