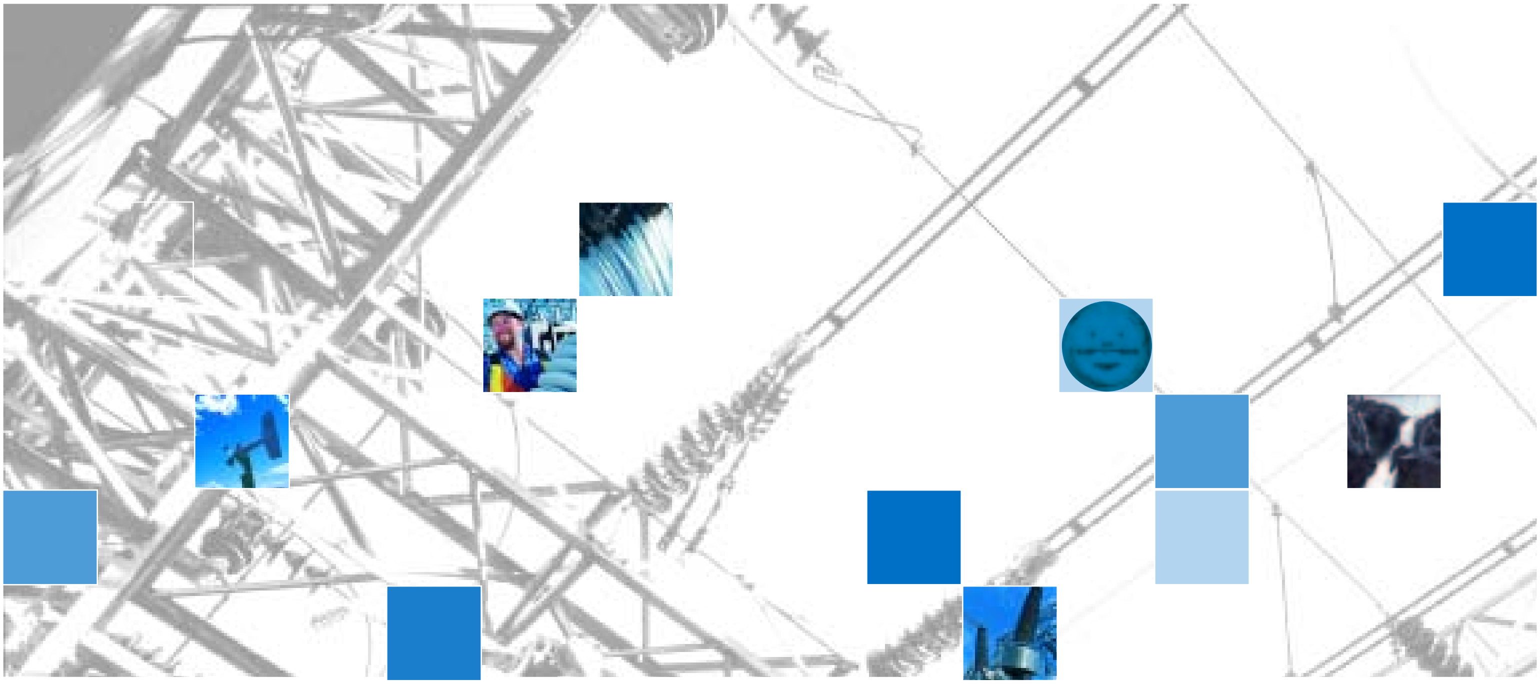

Third Quarter Report

FOR THE THREE MONTHS ENDED DECEMBER 31, 2004

BC hydro

LG04-119

Third Quarter Report

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1. Overview

KEY HIGHLIGHTS

Financial

On October 29, 2004, the B.C. Utilities Commission (BCUC or the Commission) issued its Decision related to BC Hydro's Revenue Requirements Application dated December 15, 2003. The major impacts resulting from this Decision are:

- BC Hydro is entitled to a rate increase of 4.85 per cent effective April 1, 2004. As BC Hydro has charged customers based on an approved interim rate increase of 7.23 per cent effective April 1, 2004, BC Hydro will refund its customers $38 million, including interest, based upon customers' electricity consumption during the period April 1, 2004 to November 30, 2004. The refund was charged to income this quarter.
- The establishment of a regulatory provision of $250 million for future removal and site restoration costs.
- The approval of the Heritage Deferral Account, the Non-Heritage Deferral Account, and the Trade Income Deferral Account.

On December 23, 2004, Alcan Inc. paid Powerex US$110.4 million, the full value of an arbitration award of US$100 million plus US$10.4 million in interest to settle obligations under a Power Purchase and Sale Agreement. The amount of $137 million is included in earnings this quarter and is included in the calculation of the trade income deferral account balance.

Income before regulatory account transfers for the three months ended December 31, 2004, is $197 million compared with $103 million for the same period last year. The receipt of the Alcan payment was the main driver of the increased income for the quarter. Energy costs are up as higher purchase volumes compensate for lower hydro generation.

Net income for the three months ended December 31 is $165 million, compared with $103 million in the previous year. A significant portion of the increased energy costs and the Alcan payment are transferred to the deferral accounts.

Income before regulatory account transfers for the nine months ended December 31, 2004, is $216 million compared with $142 million for the same period last year. Net income is $309 million for the nine months ended December 31, compared with $142 million for the same period last year. Higher revenues from increased rates and volumes and the Alcan payment were the main drivers of the increase over 2003. The higher costs of energy are offset in part by transfers to the deferral accounts.

BC Hydro's forecast income before regulatory account transfers for fiscal 2005 is approximately $310 million, up $70 million from the forecast disclosed in the quarterly report for the six months ended September 30, 2004. The $70 million increase from the previous forecast income is largely due to the $137 million arbitration award from Alcan Inc., which is partly offset by a forecast increase in energy purchases due to lower-than-normal water inflows and availability of low-cost generation. The forecast includes the rate increase of 4.85 per cent approved by the Commission in October 2004.

After taking the regulatory accounts into consideration, the current forecast net income for fiscal 2005 is $431 million, compared with $424 million in the forecast referenced in the report for the six months ended September 30, 2004.

Performance Plan

BC Hydro had a successful third quarter as reflected in its performance measures. Five of the six corporate measures either met (2) or exceeded (3) their quarterly targets. For more information on corporate measures, see "Performance Measures – BC Hydro Overall."

KEY HIGHLIGHTS

System Operations

BC Hydro's system storage is slightly above average as lower than average system inflows were more than offset by energy purchases in the August to December period. Year-to-date system inflows are 93 per cent of average. To compensate for lower hydro generation volumes, the higher level of electricity purchases that has occurred through the first nine months of fiscal 2005 is expected to continue through the fourth quarter.

Resource Acquisition

VANCOUVER ISLAND CALL FOR TENDERS

Duke Point Power Limited Partnership (LP) has been offered an electricity purchase agreement after being selected as the successful bidder under the terms of the Vancouver Island Call for Tenders (VI CFT). The Duke Point Power Project was determined through the VI CFT process to be the most cost-effective resource addition for Vancouver Island. BC Hydro will have a contract for 252 megawatts from the project, a gas-fired combined cycle plant to be located near Nanaimo. The BCUC decided to convene an oral hearing in January 2005 to review the cost-effectiveness of the CFT outcome against other potential options. If the contract is approved by the BCUC, construction of the project is scheduled to begin in April 2005, with commercial operation expected in May 2007.

GEORGIA STRAIT CROSSING PROJECT

On December 20, BC Hydro and Williams Gas Pipelines announced the cancellation of the proposed $340 million Georgia Strait Crossing (GSX) pipeline project. The project had been proposed as the best way to supply natural gas for electricity generating facilities on Vancouver Island. It has now been determined that there are other, lower-cost alternatives to meet Vancouver Island's natural gas requirements.

BC CLEAN ENERGY

The BC Clean Energy target (50 per cent of incremental load) is being met with committed efficiency improvements and acquisitions pursuant to calls for Customer-Based Generation and Green Power issued in 2002; 654 GWh of clean energy has been delivered to BC Hydro for the nine months to December 31.

OPEN CALLS FOR FIRM ENERGY

On October 28, 2004, BC Hydro announced its intention to issue a series of open calls, in the spring of 2005 and fall of 2006, to the private sector to acquire as much as 2,000 GWh of new firm energy. The first call of 1,000 GWh will be filed with BC Hydro's Resource Expenditure and Acquisition Plan in early 2005. The open call is designed to acquire firm power from a full range of potential resources. BC Hydro remains committed to offsetting the impact of emissions resulting from projects that receive contracts under the open calls.

2005 INTEGRATED ELECTRICITY PLAN

BC Hydro has initiated its 2005 Integrated Electricity Plan (IEP) with a comprehensive stakeholder engagement process involving a broad range of individuals and organizations and representing the interests of First Nations, industry, business, environmental groups, customers and the public in discussions around energy planning and on preferred future energy resources required to meet the province's growing demand for electricity. The desire is to reach consensus on a preferred long-term portfolio to include in the 2005 IEP that will be filed for information with the BCUC by the end of 2005.

Achievements

In October BC Hydro outlined the company's new purpose and long-term goals. "Reliable power, at low cost, for generations" is now the guiding purpose of the company. "Reliable power" is a foundation piece for BC Hydro as it is an important component of BC Hydro's service commitment to customers. "Low cost" reflects the value BC Hydro will provide back to its shareholder and its customers. "For generations" reflects BC Hydro's desire to be successful over the long term and has sustainability at its core. BC Hydro has set a total of 15 long-term goals for the next 20 years, grouped in categories related to the customer, employee, social, environmental and financial elements of its business.

KEY HIGHLIGHTS

BC Hydro's Power Smart initiative met the cumulative energy savings target of 1,200 GWh for the third quarter in the third year of the Power Smart 10-Year Plan. The goal for the 10-Year Plan is to acquire over 3,600 GWh, providing for 35 to 40 per cent of new load growth over the same 10-year period.

BC Hydro's Water Use Planning (WUP) program received two awards during the third quarter. In October the Association of Professional Engineers and Geoscientists of B.C. presented its inaugural 2004 Sustainability Award to BC Hydro. The award was created to recognize important contributions to the well-being of human life and ecosystems. In November the WUP program received the Caring for Ecosystems Award from the Fraser Basin Council. The award honours stewards of the environment and natural resources and recognizes initiatives that respect ecosystems and their interrelationships.

Year-to-date net new customer additions totalled 18,374, an increase of approximately nine per cent over the same period last year. Due to the general strength of the economy, this upward trend is expected to continue for the remainder of the fiscal year.

Challenges

On November 23, 2004, BC Hydro announced that it would not continue due diligence work regarding the potential acquisition of Columbia Power Corporation (CPC) and Columbia Basin Trust Energy Inc. (CBTE). This was in response to the decision of the Columbia Basin Trust (CBT) Board of Directors on November 20, 2004, not to proceed based on community feedback that was generally not supportive of the transaction.

The first major windstorm of this season hit B.C. on November 13 and 14, 2004, causing extended outages across the province. Downed power lines shut down power to approximately 37,000 customers. Vancouver Island, the Queen Charlotte Islands, and East Fraser Valley were hardest hit, especially in remote areas. All outages were restored by Monday, November 15.

On November 15, 2004, winds moved into the Lower Mainland causing outages in Abbotsford and Surrey as well as locations on Vancouver Island. By mid-morning, almost 28,000 customers were without electricity. All outages were restored within a few hours.

2. Performance Measures

BC HYDRO OVERALL

Performance measurement, both financial and non-financial, is an integral part of BC Hydro's strategic management process. Performance measures and targets that align with BC Hydro's strategic goals and objectives are set out in the company's February 2004 Service Plan. This section provides BC Hydro overall performance results for the third quarter ending December 31, 2004.

LEGEND (for all Performance Measures)

▲	Significantly better than target
●	Meets target (within range)
▼	Significantly below target

Income before Regulatory Account Transfers
(in millions) ▲

Annual target – $406 million

	Actual	Target
Q3 04/05	$197	$153
Q3 03/04	$103	$11

The receipt of the Alcan payment was the main driver of the increased income for the quarter.

Reliability ●

Annual target – 99.970%

ASAI	Actual	5-year average*
Q3 04/05	99.957%	99.941%
Q3 03/04	99.930%	99.941%

Annual Target – 2.15 hours

CAIDI	Actual	5-year average*
Q3 04/05	2.57 hours	2.91 hours
Q3 03/04	2.71 hours	2.91 hours

*A number of seasonal factors impact the reliability measures. The average results for the quarter in the previous five years is presented for comparative purposes.

Typically, CAIDI and ASAI are reported on a rolling 12-month basis. For the purposes of this report, the measures have been calculated on a quarterly basis for the period from October 1 to December 31. This enables BC Hydro to better identify the effect of specific events that adversely impact performance, with a view to implementing corrective action where appropriate.

ASAI and CAIDI are better than the five-year (fiscal 2000 to 2004) average, due to the absence of major events.

For the third quarter, 1,597,100 customer hours were lost, down 37 per cent from the same period last year. The improvement is due to the absence of major events, such as the October 28, 2003, windstorm, which adversely impacted reliability in the same period in 2003/2004. Leading causes of customer interruptions in this quarter included source (generation or transmission) outages (34 per cent), trees (26 per cent) and distribution equipment failures (9 per cent). In terms of customer hours lost, leading causes included trees (42 per cent), source outages (14 per cent) and distribution equipment failures (11 per cent).

BC HYDRO OVERALL

All Injury Frequency ▲

Annual target – 2.7

	Actual	Target
Q3 04/05	2.0	2.8
Q3 03/04	2.7	3.1

The volume of incidents in the latter half of the quarter was particularly low. BC Hydro is in a strong position to meet and even outperform the year-end target expectations. Continued emphasis on safety responsibilities and integration of safety in all work activity is having a sustained impact. The major contributor to the overall AIF reduction has been the medical aid only (non-disabling) incidents. The disabling category has seen a minimal reduction from historic levels.

The comparison between the third quarter last year and this year further demonstrates the significant volume reduction this quarter. In addition to the general corporate efforts in safety management, many factors can impact incident volume (both positively and negatively) and be difficult to assess on a short-term basis. Examples of these are weather patterns, volume of construction/ repair/maintenance activity, and random variability. There is no unusual feature in the third quarter that could be considered particularly influential in the current excellent results.

Should performance continue at or near the current 12-month rolling level for the balance of the fiscal year, BC Hydro could attain an AIF that is 10 per cent or more below target.

Environmental Regulatory Compliance ▲

Annual Target – 28 incidents

	Actual	Target
Q3 04/05	1 incident	7 incidents
Q3 03/04	5 incidents	7 incidents

Note: Fiscal 2004/2005 actual and target no longer include the British Columbia Transmission Corporation's (BCTC) externally reportable, preventable environmental incidents. Fiscal 2003/2004 third quarter actual and target have been adjusted to remove BCTC results, for comparison purposes.

Third quarter results are better than (i.e., below) the apportioned annual target for this quarter. The one ERC incident recorded for the quarter was not categorized as "severe". Based on performance to date, BC Hydro expects to better the annual ERC target.

Conservation Gigawatt Hours ▼

Annual Target – 500 GWh

	Actual	Target
Q3 04/05	70 GWh/year	100 GWh/year
Q3 03/04	133 GWh/year	125 GWh/year

Demand-side management programs are 30 GWh/year below target for the third quarter. This is due to the achievement of certain opportunities in prior periods and a change in reporting that establishes more accurate reporting of implementation dates for projects. Cumulative demand-side management programs are 8 GWh/year above target at the end of the quarter.

BC HYDRO OVERALL

The industrial sector is ahead of plan due to a shift in timing of a large project. The residential sector is also ahead of plan, primarily due to higher-than-expected activity with the Refrigerator Buy-Back program and a shift in timing with the Compact Fluorescent Light program. The commercial sector is below plan, due to lower-than-anticipated activity levels. Program adjustments are being initiated to close the gap.

The actual number of GWh/year includes discounts for free riders, free drivers and measurement and verification. Free riders refers to those who participate in a program but would have done so without BC Hydro's involvement; free drivers refers to those who do not participate in a program (e.g., use a coupon) but are influenced by it and proceed because of it; measurement and verification allows for energy savings that may be lower than initial estimates when actually measured.

Approved Strategic Workforce Planning Positions Filled ●

Annual Target – 71

	Actual	Target
Q3 04/05	17	16
Q3 03/04	0	0

In the third quarter, one Field Services trainee manager was hired ahead of the scheduled fourth-quarter intake. No strategic workforce planning hires were planned for the third quarter last year.

GREENHOUSE GAS EMISSIONS

	Emissions (millions of tonnes CO_2e)		
	F2005 Q1	F2005 Q2	F2005 Q3
Emissions if No Action Taken	**2.03**	**1.57**	**1.04**
Avoided Emissions			
Customer efficiency programs	0.39	0.30	0.16
Purchase of cleaner power***	0.25	0.18	0.06
Internal efficiency improvements	0.13	0.12	0.02
Total	**0.77**	**0.60**	**0.25**
Actual Emissions			
BC Hydro facilities	0.08	0.13	0.13
Independent Power Producers	0.26	0.29	0.31
Net electricity imports	0.92	0.55	0.35
Total	**1.26**	**0.97**	**0.79**
Offsets			
Island Cogeneration Project	**0.06**	**0.09**	**0.09**
Total	**1.20**	**0.88**	**0.70**
GHG intensity (t/GWh)	**96**	**52**	**57**

BC Hydro emits greenhouse gases (GHG) from its thermal plants, vehicles, buildings and some equipment. As well, some of BC Hydro's Independent Power Producers and import sources of electricity produce greenhouse gases. BC Hydro avoids GHG emissions by avoiding new load through Power Smart, increasing the generating efficiency of existing plants through Resource Smart, and purchasing and exporting BC Clean Electricity. BC Hydro also directly offsets the GHG emissions from some plants.

For the third quarter, greenhouse gas emissions attributable to the electricity supplied to customers in B.C. are estimated* at .70 million tonnes CO_2e**, or 57 tonnes CO_2e per gigawatt hour. The emissions intensity of BC Hydro's electricity fluctuates seasonally and annually with the supply of water to its reservoirs and the status of the electricity market.

Total GHG emissions were 0.18 million tonnes CO_2e lower in the third quarter compared with the second quarter, mainly due to decreased imports and thermal facility operations.

* Based on actuals for October and November and estimates for December for most emission sources.
** CO_2e or Carbon Dioxide equivalent tonne is a universal unit of measure for greenhouse gas emissions.
*** Net of sales of Green Power Certificates.

3. Financial

MANAGEMENT DISCUSSION AND ANALYSIS

The Management Discussion and Analysis reports on BC Hydro's consolidated results and financial position. This discussion should be read in conjunction with the Management Discussion and Analysis presented in the 2004 Annual Report, the 2004 Annual Consolidated Financial Statements of BC Hydro and the interim consolidated financial statements of BC Hydro for the three and nine months ended December 31, 2004 and 2003. 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 materially from those contemplated in the forward-looking statements.

In 2004 BC Hydro returned to regulation by the British Columbia Utilities Commission (BCUC) which included the establishment of regulatory accounts for certain costs. These accounts impact the comparability of 2004 to 2003.

Consolidated Results of Operations

Income before regulatory account transfers of $197 million for the three months ended December 31, 2004, compares with $103 million in the same period in the previous year. The primary reason for the increase in income is payment of an arbitration award from Alcan Inc. of $137 million. This arbitration award is discussed in the "Payment from Alcan Inc." section of the Management Discussion and Analysis. Higher revenues from the interim rate increase and continued strong customer demand for electricity in the industrial and commercial sectors were partially offset by lower residential demand and the recognition in the quarter of a $38 million refund owed to customers as a result of the Commission's decision on rates. The final decision on rates is a 4.85 per cent annual rate increase over fiscal 2004.

The impacts of the Alcan payment and the higher net revenues were partially offset by an increase in energy costs as a result of lower-than-average water inflows experienced this year.

Net income is $165 million for the three months ended December 31, 2004, compared with $103 million in the same period in the previous year. A significant portion of the increased energy costs and the Alcan payment are transferred to the deferral accounts, which is a major consideration in the year-over-year net income performance.

Income of $216 million before regulatory account transfers for the nine months ended December 31, 2004 compares with $142 million in the same period in the previous year. The primary reason for the increase is the payment from Alcan Inc. Increased energy costs due to below-average water inflows has more than offset the favourable impact of demand growth and the 4.85 per cent rate increase. Also impacting net income was an increase in amortization and lower operations, maintenance and administration expenses and finance charges.

Net income of $309 million for the nine months ended December 31, 2004, compares with $142 million in the nine-month period in the previous year. A significant portion of the increased energy costs and the Alcan payment are transferred to the deferral accounts. These transfers are a major consideration in the year-over-year net income performance.

MANAGEMENT DISCUSSION AND ANALYSIS

OPERATING HIGHLIGHTS

	For the Three Months Ended December 31		*For the Nine Months Ended December 31*	
in gigawatt hours	**2004**	2003	**2004**	2003
Electricity Sold				
Residential	**4,620**	4,797	**10,825**	11,041
Light industrial and commercial	**4,496**	4,435	**12,893**	12,693
Large industrial	**4,023**	3,972	**12,060**	11,505
Other energy sales	**530**	565	**1,186**	1,205
	13,669	13,769	**36,964**	36,444
Electricity trade	**7,362**	7,103	**22,665**	23,255
	21,031	20,872	**59,629**	59,699

Domestic Revenues

Domestic revenues of $692 million for the three months ended December 31, 2004 were $6 million higher than the same period in the previous year. A 4.85 per cent rate increase over 2003 increased revenues, but warmer temperatures resulted in a reduction in residential volumes. Commercial and large industrial volumes increased by approximately one per cent. In addition to these operating impacts, revenues in the quarter were reduced by the $38 million rate refund, for the period April 1 to November 30, as a result of the final decision from the Commission.

Domestic revenues of $1,940 million for the nine months ended December 31, 2004, were $106 million higher than the same period in the previous year. Key factors in this increase are the 4.85 per cent rate increase effective April 1, 2004, and net growth in domestic demand of one per cent compared with the first nine months of the previous year. Consumption in the large industrial and commercial sectors has increased by three per cent as activity levels have increased due to improved economic conditions in the province. Residential consumption has decreased by two per cent primarily due to warmer weather compared with the first nine months of the previous year.

Electricity 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. Electricity trade activities are carried out by Powerex, a wholly owned subsidiary of BC Hydro. While it engages in electricity trade, BC Hydro ensures that its ability to meet domestic requirements is not put under undue risk as a result of these transactions. Electricity 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 that domestic demand requirements can be met. Electricity trade revenues also include natural gas sales related to thermal generation requirements.

Electricity trade revenues for the three months ended December 31, 2004 were $278 million compared with $224 million in the same period in the prior year. The increase is due to higher sales volumes and higher average sales prices. Sales volumes increased four per cent compared with the same period last year. Average sales prices increased 13 per cent, to $62/MWh from $55/MWh in the prior year. Increasing gas prices and transmission restrictions into the California market resulted in increased power prices.

Electricity trade revenues for the nine months ended December 31, 2004, were $746 million, an increase of $40 million from the same period in the prior year. The increase was due to a five per cent increase in average sales prices, to $63/MWh from $60/MWh in the prior year. The effect of higher average sales prices was partly offset by a three per cent decrease in sales volumes, to 22,665 GWh in the nine months ended December 31, 2004, from 23,255 GWh in the same period last year. The increase in market prices is caused by several factors including less energy available from low-cost hydro generation in the region and tighter natural gas supplies. The decrease in sales volumes was due primarily to lower water inflows and reservoir levels and transmission restrictions into the California market.

Energy Costs

The mix of sources of supply is impacted by variables such as the market price of energy, water inflows, reservoir levels, energy demand and environmental and social impacts.

Energy costs are made up of the following sources of supply:

	For the three months ended December 31					
	($ in millions)		(gigawatt hours)		($ per MWh)	
	2004	2003	**2004**	2003	**2004**	2003
Hydro[1]	**$ 62**	$ 70	**11,662**	12,331	**$ 5.32**	$ 5.68
Purchases from Independent Power Producers and other long-term contracts	**111**	97	**1,837**	1,637	**60.42**	59.25
Other electricity purchases[2]	**234**	148	**8,738**	7,883	**53.44**	47.82
Natural gas	**62**	59	**113**	111	**141.60**	108.11
Transmission charges and other expenses	**36**	30	**37**	21	**–**	–
Total	**$ 505**	$ 404	**22,387**	21,983	**$ 31.13**	$ 25.85

	For the nine months ended December 31					
	($ in millions)		(gigawatt hours)		($ per MWh)	
	2004	2003	**2004**	2003	**2004**	2003
Hydro[1]	**$ 163**	$ 179	**29,343**	31,160	**$ 5.55**	$ 5.74
Purchases from Independent Power Producers and other long-term purchase contracts	**295**	281	**4,843**	4,682	**60.91**	60.02
Other electricity purchases[2]	**692**	496	**28,246**	26,655	**52.35**	49.56
Natural gas	**155**	144	**497**	323	**109.05**	108.36
Transmission charges and other expenses	**116**	101	**78**	61	**–**	–
Total	**$1,421**	$1,201	**63,007**	62,881	**$ 33.38**	$ 30.05

1 Net of storage exchange due to Non-Treaty Storage Agreement with Bonneville Power Administration, Kootenay Canal Plant Agreement with Fortis BC, and Keenleyside Entitlement Agreement with Columbia Power Corporation.

2 Other electricity purchases in dollars includes purchases for trade activities shown net of derivatives. Gigawatt hours and $ per MWh are shown at gross cost.

Water inflows into BC Hydro's reservoirs were four per cent lower at December 31, 2004 compared with December 31, 2003. This resulted in a reduction in the volume of low-cost hydro generation. Reduced hydro generation volumes are compensated for by increased electricity imports. The decision to import energy instead of utilizing hydro generation is based on many factors, such as the forecast market price of energy in future periods relative to the current period, current reservoir levels 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.

For the three months ended December 31, 2004, energy costs of $505 million were $101 million higher than in the same period in the previous year. The increase in energy costs is due to electricity imports to meet domestic load requirements and increased unit prices for purchased energy. For the three months ended December 31, 2004, imports were 1,250 GWh, compared with 1,106 GWh for the same period for the previous year.

For the nine months ended December 31, 2004, energy costs of $1,421 million were $220 million higher than the same period in the previous year. Electricity imports for the nine months ended December 31, 2004, were 5,900 GWh compared with 3,739 GWh for the same period of the previous year. Lower hydro generation in the region also increased market prices for purchased electricity.

Operations, Maintenance and Administration

Total operations, maintenance and administration expenditures of $147 million for the three months ended December 31, 2004, are consistent with the same period in the previous year.

Total operations, maintenance and administration expenditures for the nine months ended December 31, 2004 were $25 million lower than for the same period in the previous year. The primary reasons for the decrease are the completion of major projects last year ($7 million), lower maintenance costs for thermal generation ($4 million), lower system restoration cost due to forest fires ($2 million), and lower costs associated with California power markets litigation ($12 million).

Amortization Expense

Amortization expense for the three months ended December 31, 2004, was $8 million higher than for the same period in the previous year. For the nine months ended December 31, 2004, amortization expense was $27 million higher than for the same period in the previous year. The increase in amortization expense is primarily due to an increased level of capital assets in service and deferred demand-side management expenditures incurred in the prior year.

Finance Charges

Finance charges for the three months ended December 31, 2004, were $8 million lower than for the same period in the previous year. The decrease in finance charges is primarily due to decreased interest expense on U.S. denominated debt due to a stronger Canadian dollar compared with the U.S. dollar ($5 million), higher finance charges capitalized and lower interest rates on debt refinancing.

Finance charges for the nine months ended December 31, 2004, were $12 million lower than for the same period in the previous year. The decrease in finance charges is primarily due to lower interest rates on debt refinancing ($13 million), and a stronger Canadian dollar compared with the U.S. dollar ($10 million). These favourable variances were partly offset by lower sinking fund income ($10 million) and lower finance charges capitalized ($4 million).

Payment from Alcan

During fiscal 2002, Enron Corp. (Enron) and certain of its subsidiaries, including Enron Power Marketing, Inc. (EPMI), filed for bankruptcy protection. As a result, Powerex's Power Purchase and Sale Agreement with EPMI terminated, giving rise to a termination payment becoming due from EPMI. Under a 1997 agreement among Alcan Inc., formerly Alcan Aluminum Limited (Alcan), EPMI, Powerex and BC Hydro, Alcan agreed to remain liable to Powerex for payment obligations of EPMI up to US$100 million.

On December 23, 2004, Alcan paid Powerex US$110.4 million, the full value of the arbitration award of US$100 million plus US$10.4 million in interest. The amount of $137 million is included in earnings this quarter and is included in the calculation of the transfer to the trade income deferral account.

Liquidity and Capital Resources

Cash flow provided by operating activities for the three months ended December 31, 2004, was $339 million, compared with $251 million for the same period in the previous year. The primary reasons for the increase in cash flow provided by operating activities are the increase in net income, transfers to the regulatory accounts and changes in working capital. The accrual of the refund to customers associated with the rate increase is the largest single factor in the change in working capital. Cash flow provided by operating activities for the nine months ended December 31, 2004, of $489 million compared with $423 million for the same period in the previous year.

Capital expenditures, including demand-side management programs, were as follows:

	Three months ended December 31		*Nine months ended December 31*	
(in millions)	**2004**	2003	**2004**	2003
Generation replacements and expansion	**$ 33**	$ 34	**$ 89**	$ 99
Transmission lines and substation replacements and expansion	**30**	48	**83**	132
Distribution improvements and expansion	**61**	52	**175**	144
General – computers, vehicles, etc.	**10**	17	**30**	58
Change in working capital related to capital asset expenditures[1]	**5**	1	**7**	38
Capital asset expenditures per Consolidated Statement of Cash Flows	**139**	152	**384**	471
Power Smart (Demand-side management)	**11**	21	**51**	40
Total capital expenditures per Consolidated Statement of Cash Flows	**$150**	$173	**$435**	$511

1 Adjustment from accrual to cash expenditures on the Consolidated Statement of Cash Flows

For the nine months ended December 31, 2004, the decrease in Transmission lines, substation improvements and expansion is due to the costs of two significant projects that were underway in 2003. The increase in Distribution improvements and expansion is due to a higher volume of customer construction. The decrease in general expenditures is primarily due to the completion of a major integrated information system in the previous year. The increase in Power Smart expenditures is due to timing of incentive payments based on customer-driven project schedules.

During the quarter, revolving borrowings were paid down with the improved cash flows from operations. At December 31, 2004, the cash received from the Alcan settlement remained in short-term investments. During the nine months ended December 31, 2004, BC Hydro issued $540 million of new bonds. The funds from these issues and cash flows from operations have been used to redeem $523 million of bonds, fund the payment to the province and capital expenditures. The net long-term debt balance at December 31, 2004 was $6,849 million, compared with $6,900 million at March 31, 2004. The Canadian dollar at December 31, 2004 was US$0.8308, compared with US$0.7631 at March 31, 2004.

Revenue Requirement Application

On October 29, 2004, the Commission issued its Decision related to BC Hydro's Revenue Requirements Application dated December 15, 2003. The major impacts resulting from this decision are:

- BC Hydro is entitled to a rate increase of 4.85 per cent effective April 1, 2004. As BC Hydro has charged customers based on an approved interim rate increase of 7.23 per cent effective April 1, 2004, BC Hydro will refund its customers $38 million, including interest, based upon customers' consumption during the period April 1, 2004 to November 30, 2004. The refund was accrued this quarter and will be credited to customers' bills in the fourth quarter.
- The Commission ordered a variance from Section 3110 of the CICA Handbook, "Asset Retirement Obligations," resulting in the establishment of a regulatory provision for future removal and site restoration costs. Dismantling costs incurred due to removal of capital assets and site restoration are charged against the provision if they do not relate to an asset retirement obligation. This provision was established by a transfer from Retained Earnings of $250 million. This regulatory provision is further described in the "Regulatory Accounts" section of the Management Discussion and Analysis.
- The Commission approved the Heritage Deferral Account, the Non-Heritage Deferral Account, and the Trade Income Deferral Account. These accounts are further described in the "Regulatory Accounts" section of the Management Discussion and Analysis.

Powerex Legal Proceedings

At December 31, 2004, Powerex was owed US$269 million (CDN$324 million) by the California Power Exchange (Cal Px) and the California Independent System Operator (Cal ISO) 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 Cal ISO were unable to pay these amounts to Powerex. In addition, certain California parties requested the Federal Energy Regulatory Commission (FERC) to consider whether refunds should be made to the Cal PX, the Cal ISO and the California Department of Water Resources by various suppliers, including Powerex.

Powerex has been named, along with other energy providers, as a defendant in a number of lawsuits and regulatory proceedings that allege 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. On September 9, 2004, the U.S. Ninth Circuit Court issued a ruling in the case Lockyer v. FERC. In its ruling, the court stated that the FERC "abused its administrative discretion by declining to order refunds for violations" of the agency's reporting rules under the Federal Power Act, and sent the case back to FERC for further consideration. The ruling may impact a number of issues previously decided by FERC, including Powerex's US$1.3 million FERC Settlement Agreement.

BC Hydro was also directly joined as a defendant in the California Consumer Class Action lawsuit. In response to an application by BC Hydro to be dismissed from the lawsuit, a U.S. Federal Court judge ruled that, except for Powerex, BC Hydro is immune from these claims in the United States by virtue of the Foreign Sovereign Immunity Act. The U.S. Court of Appeals for the Ninth Circuit upheld this finding, and removed BC Hydro from the lawsuit. The court also upheld the finding that Powerex does not enjoy foreign sovereign entity status and therefore remains a party to the lawsuit, which was remanded back to California State Court.

Due to the 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 and BC Hydro.

Management cannot predict whether the amounts owed by the Cal PX and Cal ISO are recoverable, or whether amounts may need to be refunded as a result of the FERC proceedings. BC Hydro 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 may differ materially 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 collection process.

Regulatory Accounts

Deferral Accounts

As disclosed in the Management Discussion and Analysis in the 2004 Annual Report, the Province issued a Special Directive that directs the British Columbia Utilities Commission to authorize BC Hydro to establish the Heritage Deferral Account and the Trade Income Deferral Account effective April 1, 2004. As part of the Revenue Requirement Application related to fiscal 2005 and 2006, BC Hydro also applied to the Commission for the establishment of a Non-Heritage Deferral Account. The accounting requirements related to these accounts were approved by the Commission in its Decision of October 2004. These accounts are intended to result in assigning domestic ratepayers the benefit of BC Hydro's low-cost generation assets (the "Heritage Resources") and other related activities, as well as an appropriate share of risks associated with the ownership and operation of these assets. The impact of these accounts is to defer certain types of cost variances through transfers to/from the accounts by adjustment of net income.

During the quarter, the balance of the trade income deferral account reached its maximum as defined in the Special Directive and BCUC Decision.

Regulatory Provision for Future Removal and Site Restoration Costs

As a result of the BCUC's decision in October, 2004 and effective April 1, 2004, BC Hydro was required to establish a regulatory provision for future removal and site restoration (FRSR) costs not covered by the asset retirement obligation accounting standards. The initial amount of the provision is $250 million. Costs of dismantling capital assets will be applied to this regulatory liability if they do not otherwise relate to an asset retirement obligation under Section 3110 of the CICA Handbook.

MANAGEMENT DISCUSSION AND ANALYSIS

BC Hydro has recorded the following amounts in the financial statements for the three and nine months ended December 31, 2004, including accrued interest on deferral account balances of $4 million:

	Income Statement		Balance Sheet
	Three months ended	*Nine months ended*	*As at*
in millions	*December 31, 2004*		*December 31, 2004*
	Increase (Decrease) net income		Asset (Liability)
Heritage Deferral Account	$ 17	$ 154	$ 158
Non-Heritage Asset Deferral Account	27	58	59
Trade Income Deferral Account	(86)	(129)	(130)
Net Deferral Accounts	$(42)	$ 83	$ 87
Regulatory Provision for FRSR	$ 10	$ 10	$(240)

Columbia Basin Power Projects

On September 30, 2004, the BC Hydro Board of Directors approved in principle a proposal to acquire the assets of Columbia Power Corporation (CPC) and the Columbia Basin Trust Energy Inc. (“CBT Energy”). Both CPC and CBT Energy are subsidiaries of the Province.

CPC and CBT Energy jointly own hydroelectric facilities comprising two operating facilities, one under construction and one project in development.

On November 23, 2004, BC Hydro announced that it would suspend its due diligence related to this potential acquisition. This was based on the decision by the owner of CBT Energy that it was not comfortable moving forward with the proposed sale.

Business Risks/Uncertainties

BC Hydro is subject to various risks and uncertainties that cause significant volatility in its earnings. Factors such as the level of water inflows into its reservoirs, market prices for electricity and natural gas, interest rates, foreign exchange rates, weather and regulatory and government policies influence both the operation of the BC Hydro system and its earnings. A reduction in water inflows into reservoirs results in a greater reliance on energy purchases or use of the Burrard Generating Station, both of which can increase the costs of energy. While these risks cannot be eliminated, as they are largely non-controllable, some may be mitigated to a certain degree as disclosed in BC Hydro’s 2004 Annual Report.

Management’s assessment of business risk/uncertainties is ongoing and the risks/uncertainties to BC Hydro have not changed materially from the Management Discussion and Analysis presented in the 2004 Annual Report.

Future Outlook

BC Hydro’s income for this fiscal year is forecast to be $310 million before any transfers to/from the regulatory accounts. This is an increase of $70 million from the forecast disclosed in BC Hydro’s second quarter report for fiscal 2005. The $70 million increase in forecast income is largely due to the $137 million arbitration award from Alcan Inc. The increase in forecast income due to the arbitration award is partly offset by a forecast increase in energy purchases due to lower-than-normal water inflows and availability of low-cost hydro generation. BC Hydro’s income can fluctuate significantly due largely to non-controllable factors such as the market price of energy, weather, interest rates, and water inflows. The range of income before regulatory account transfers under plausible scenarios is estimated to be between $275 million and $395 million.

BC Hydro’s forecast net income after regulatory account transfers for fiscal 2005 is approximately $431 million. The forecast of $431 million is after the impacts of lower water inflows, higher energy purchase volumes and prices and an increase in trade income have been taken into account through the deferral accounts

FINANCIALS

CONSOLIDATED STATEMENT OF OPERATIONS

(Unaudited)	*For the three months Ended December 31*		*For the nine months Ended December 31*	
(in millions)	**2004**	2003 *(Restated – Note 4)*	**2004**	2003 *(Restated – Note 4)*
Revenues				
Residential	**$ 286**	$ 277	**$ 701**	$ 667
Light industrial and commercial	**238**	235	**713**	674
Large industrial	**135**	135	**427**	391
Other energy sales	**21**	23	**59**	59
Miscellaneous	**12**	16	**40**	43
	692	686	**1,940**	1,834
Electricity trade	**278**	224	**746**	706
	970	910	**2,686**	2,540
Expenses				
Energy costs	**505**	404	**1,421**	1,201
Operations	**53**	51	**153**	163
Maintenance	**62**	61	**180**	189
Administration	**32**	32	**93**	99
Taxes	**36**	37	**107**	108
Amortization	**112**	104	**328**	301
	800	689	**2,282**	2,061
Income Before the Following Items	**170**	221	**404**	479
Finance charges	**(110)**	(118)	**(325)**	(337)
Payment from Alcan Inc. (Note 7)	**137**	–	**137**	–
Income Before Regulatory Account Transfers	**197**	103	**216**	142
Regulatory Account Transfers (Note 6)				
Heritage Deferral Account	**17**	–	**154**	–
Non-Heritage Deferral Account	**27**	–	**58**	–
Trade Income Deferral Account	**(86)**	–	**(129)**	–
Regulatory provision for future removal and site restoration costs	**10**	–	**10**	–
Net Income	**$ 165**	**$** 103	**$ 309**	**$** 142

See accompanying notes to the interim consolidated financial statements.

FINANCIALS

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

(Unaudited) (in millions)	for the nine months ended December 31 2004	2003 (Restated – Note 4)
Retained earnings, beginning of period as previously reported	**$ 1,634**	$ 1,609
Adoption of new accounting standard for asset retirement obligations (*Note 4)*	**241**	229
Retained earnings, beginning of period as restated	**1,875**	1,838
Transfer to Regulatory provision for future removal and site restoration costs (Note 6)	**(250)**	–
Net income	**309**	142
Accrued Payment to the Province	**(252)**	(115)
Retained earnings, end of period	**$ 1,682**	$ 1,865

See accompanying notes to the interim consolidated financial statements.

FINANCIALS

CONSOLIDATED BALANCE SHEET

(Unaudited) (in millions)	***as at December 31*** **2004**	*as at March 31* 2004 *(Restated – Note 4)*
ASSETS		
Capital Assets		
Capital assets in service	**$ 15,539**	$ 15,307
Less accumulated amortization	**6,232**	5,922
	9,307	9,385
Unfinished construction	**639**	515
	9,946	9,900
Current Assets		
Cash and cash equivalents	**198**	47
Accounts receivable and accrued revenue	**367**	323
Materials and supplies	**90**	86
Prepaid expenses	**70**	108
Unrealized gains on mark-to-market transactions	**98**	104
	823	668
Other Assets and Deferred Charges		
Loan receivable	**1**	2
Sinking funds	**904**	981
Demand-side management programs	**195**	161
Deferred debt costs	**15**	150
Regulatory accounts *(Note 6)*	**87**	–
	1,202	1,294
	$ 11,971	$ 11,862
LIABILITIES AND EQUITY		
Long-Term Debt		
Long-term debt net of sinking funds	**$ 5,897**	$ 5,927
Sinking funds presented as assets	**904**	981
	6,801	6,908
Foreign Currency Contracts	**100**	63
Current Liabilities		
Current portion of long-term debt	**952**	973
Accounts payable and accrued liabilities	**595**	673
Accrued interest	**135**	115
Accrued Payment to the Province	**252**	73
Unrealized losses on mark-to-market transactions	**94**	78
	2,028	1,912
Deferred Credits and Other Liabilities		
Asset retirement obligations *(Note 4)*	**17**	16
Regulatory provision for future removal and site restoration *(Note 6)*	**240**	–
Deferred revenue	**273**	276
Contributions arising from the Columbia River Treaty	**187**	193
Contributions in aid of construction	**643**	619
	1,360	1,104
Retained Earnings	**1,682**	1,875
	$ 11,971	$ 11,862

See accompanying notes to the interim consolidated financial statements.

On behalf of the Board:

L.I. (Larry) Bell
Chair

W.C. (Wanda) Costuros
Chair, Audit and Risk Management Committee

FINANCIALS

CONSOLIDATED STATEMENT OF CASH FLOWS

(Unaudited)	*For the three months ended December 31*		*For the nine months ended December 31*	
(in millions)	**2004**	2003 *(Restated – Note 4)*	**2004**	2003 *(Restated – Note 4)*
Operating Activities				
Net income	**$ 165**	$ 103	**$ 309**	$ 142
Adjustments for:				
- Amortization	**104**	104	**320**	301
- Regulatory accounts	**42**	–	**(83)**	–
- Other non-cash items	**25**	34	**51**	26
	336	241	**587**	469
Working capital changes	**3**	10	**(108)**	(46)
Cash provided by operating activities	**339**	251	**489**	423
Investing Activities				
Loan receivable	–	(2)	**–**	(2)
Capital asset expenditures	**(139)**	(152)	**(384)**	(471)
Dismantling costs	**(10)**	(3)	**(10)**	(7)
Contributions in aid of construction	**11**	13	**46**	35
Demand-side management programs	**(11)**	(21)	**(51)**	(40)
Cash used for investing activities	**(149)**	(165)	**(399)**	(485)
Financing Activities				
Bonds:				
Issued	–	–	**540**	640
Retired	**(17)**	–	**(523)**	(300)
Revolving borrowings	**(31)**	(48)	**51**	102
Sinking funds	**8**	(8)	**60**	(5)
Deferred debt costs	–	–	**(5)**	7
Settlement of interest rate swaps	**4**	11	**11**	11
Cash provided by (used in) financing activities	**(36)**	(45)	**134**	455
Payment to the Province	–	–	**(73)**	(338)
Increase in cash and cash equivalents	**154**	41	**151**	55
Cash and cash equivalents at beginning of period	**44**	18	**47**	4
Cash and cash equivalents at end of period	**$ 198**	$ 59	**$ 198**	$ 59
Supplemental disclosure of cash flow information				
– Interest paid	**$ 106**	$ 108	**$ 369**	$ 369

See accompanying notes to the interim consolidated financial statements.

NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)

DECEMBER 31, 2004

Purpose

British Columbia Hydro and Power Authority (BC Hydro), was established in 1962 as a Crown Corporation of the Province of British Columbia (Province) by enactment of the Hydro and Power Authority Act. Its purpose is to provide reliable, low-cost power for generations. BC Hydro is subject to regulation by the British Columbia Utilities Commission (the Commission) which, among other things, approves the rates BC Hydro charges for its services.

Note 1: Accounting Policies

These 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 applied in unregulated enterprises. 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 2004 Annual Report.

These interim consolidated financial statements follow the same accounting policies as the most recent annual consolidated financial statements except as follows:

- On April 1, 2004, BC Hydro retroactively implemented new accounting standards related to Asset Retirement Obligations in accordance with the Canadian Institute of Chartered Accountants (CICA) Handbook, Section 3110. These accounting standards replace the prior accounting related to future removal and site restoration costs (Note 4).
- Effective April 1, 2004, Accounting Guideline 13, "Hedging Relationships", was adopted with respect to hedging transactions. BC Hydro also implemented the recommendations of Emerging Issues Abstract (EIC) 128 related to Accounting for Trading, Speculative or Non-hedging Derivative Financial Instruments (Note 5).
- Effective April 1, 2004, BC Hydro established various regulatory accounts either by Special Directive of the Province or otherwise, as required or approved by the Commission (Note 6).

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

Note 2: Seasonality of Operating Results

Due to the seasonal nature of the 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 3: Regulation

BC Hydro and the Commission are both subject to general or special directives and directions issued by the Province. Orders in Council from the Province establish the basis for determining BC Hydro's allowed return on equity, calculation of its revenue requirement, rates charged to customers, and the annual Payment to the Province.

On October 29, 2004, the Commission issued its Decision related to BC Hydro's Revenue Requirements Application dated December 15, 2003, that covered BC Hydro's 2005 and 2006 fiscal years. The major impacts resulting from this decision are:

- BC Hydro is entitled to a rate increase of 4.85 per cent effective April 1, 2004. As BC Hydro has charged customers based on an approved interim rate increase of 7.23 per cent effective April 1, 2004, BC Hydro will refund its customers $38 million, including interest, based upon customers' electricity consumption during the period April 1, 2004 to November 30, 2004. The refund was charged to income this quarter.

- The BCUC ordered a variance from Section 3110 "Asset Retirement Obligations" of the CICA Handbook, resulting in the establishment of a regulatory provision for future removal and site restoration costs. This account was established by a transfer from Retained Earnings. This regulatory liability is described in Note 6.
- The BCUC approved the establishment of the Heritage Deferral Account, the Non-Heritage Deferral Account, and the Trade Income Deferral Account. These regulatory deferral accounts are described in Note 6.

Note 4: Asset Retirement Obligations

Prior to March 31, 2004, BC Hydro recorded a provision for the estimated future costs associated with the retirement and decommissioning of its distribution, transmission and generation facilities in accordance with the previous requirements of CICA Handbook Section 3061. Effective April 1, 2004, BC Hydro adopted the new section (Section 3110 "Asset Retirement Obligations"), which addresses accounting and reporting for obligations associated with the retirement of long-lived assets.

This new section applies only to legal obligations associated with the retirement of long-lived assets. BC Hydro is required to record the net present value of a liability at the time it is incurred if an estimate can be determined. When a liability is initially recorded, BC Hydro will capitalize the costs by increasing the carrying value of the long-lived asset. The liability is adjusted for the passage of time through accretion (interest) expense and the asset is amortized over its useful life. The change in accounting policy has been applied retroactively, including restatement of prior periods to eliminate the provision for future removal and site restoration costs that was previously reported.

As at December 31, the net impact of this change in accounting policy is summarized below:

	2004	2003
in millions	Increase	(Decrease)
Retained Earnings, beginning of year	**$ 241**	$ 229
Capital Assets, net	**8**	8
Deferred Credit and Other Liabilities	**(233)**	(237)
Net income for nine months ended December 31	**$ –**	$ 7

Note 5: Hedging Relationships

During the year, BC Hydro implemented the requirements of CICA Accounting Guideline 13, "Hedging Relationships." This Guideline addresses the types of items that qualify for hedge accounting, including the formal documentation required to enable the use of hedge accounting and the requirement to evaluate hedges for effectiveness.

BC Hydro also implemented Emerging Issues Committee (EIC) Abstract 128, "Accounting for Trading, Speculative or Non-hedging Derivative Financial Instruments." The EIC requires derivatives that are not designated as hedges to be recorded at fair value on the balance sheet, with changes in fair value recorded in earnings.

The requirements of the Accounting Guideline and EIC were adopted prospectively for derivatives used for liability-management purposes effective April 1, 2004. The impact of this change in accounting policy is a $5 million decrease in net income for the three months ended December 31 and a $2 million increase in net income for the nine months ended December 31. The hedge accounting provisions were adopted for energy trading activities during the year ended March 31, 2004.

Note 6: Regulatory Accounts

During fiscal 2004, the Province issued a Special Directive that directs the Commission to authorize BC Hydro to establish the Heritage Deferral Account and the Trade Income Deferral Account effective April 1, 2004. As part of the Revenue Requirement Application related to fiscal 2005 and 2006, BC Hydro also applied to the Commission for the establishment of a Non-Heritage Deferral Account. The accounting requirements related to these accounts were approved by the Commission in its Decision of October, 2004. These accounts are intended to result in assigning domestic ratepayers the benefit of BC Hydro's low-cost generation assets (the "Heritage Resources") and other related activities, as well as an appropriate share of risks associated with the ownership and operation of these assets.

As at December 31, 2004, the deferral accounts on the balance sheet are:

(in millions)	Asset (liability)
Heritage Deferral Account	$ 158
Non-Heritage Asset Deferral Account	59
Trade Income Deferral Account	(130)
Total Deferral Accounts	$ 87

The deferral accounts include interest of $4 million.

Heritage Deferral Account

The Heritage Deferral Account is intended to mitigate the impact of certain variances between the forecast and actual costs of service associated with the Heritage Resources. The impact of this account is to defer the impact of these cost variances through transfers to or from the account by adjustment of net income.

Trade Income Deferral Account

The Trade Income Deferral Account is intended to mitigate the uncertainty associated with forecasting the net income of BC Hydro's electricity trade activities. The impact of this account is to defer the difference between forecast and actual Trade Income. For the purposes of this calculation, Trade Income is defined as the Net Income of Powerex based on Canadian GAAP. The Special Directive provides that in each fiscal year the portion of the variance between forecast and actual Trade Income in excess of $200 million per year or a loss in Trade Income will not be included in the Trade Income Deferral Account.

Non-Heritage Asset Deferral Account

The Non-Heritage Asset Deferral Account is intended to manage the impact of certain other non-controllable cost variances. The impact of this account would be to defer specific types of cost variance through transfers to or from the account by adjustment of net income.

Regulatory Provision for Future Removal and Site Restoration Costs

As a result of the Commission's Decision in October, 2004, BC Hydro was required to establish a regulatory provision for future removal and site restoration costs effective April 1, 2004. The initial amount of the provision was $250 million, consisting of the amount that would otherwise have been included in Retained Earnings as a result of implementing the new accounting standards for Asset Retirement Obligations. Costs of dismantling capital assets will be applied to this regulatory liability if they do not otherwise relate to an asset retirement obligation.

Note 7: Payment from Alcan Inc.

During fiscal 2002, Enron Corp. (Enron) and certain of its subsidiaries, including Enron Power Marketing, Inc. (EPMI), filed for bankruptcy protection. As a result, Powerex's Power Purchase and Sale Agreement with EPMI terminated, giving rise to a termination payment becoming due from EPMI. Under a 1997 agreement among Alcan Inc., formerly Alcan Aluminum Limited, (Alcan), EPMI, Powerex and BC Hydro, Alcan agreed to remain liable to Powerex for payment obligations of EPMI up to US$100 million.

After arbitration and numerous court appeals, on October 7, 2004, Alcan withdrew from all legal challenges to the arbitration award and signed, along with Powerex, an agreement concerning the final resolution of this matter.

On December 23, 2004, Alcan paid Powerex US$110.4 million, the full value of the arbitration award of US$100 million plus US$10.4 million in interest. This amount ($137 million) is included in earnings this quarter.

Note 8: Vancouver Island Generation and Georgia Strait Crossing Projects

During fiscal 2004, BC Hydro reviewed the status of the Vancouver Island Generation Project (VIGP) and the Georgia Strait Crossing Project (GSX). These projects were intended to satisfy future electricity supply requirements for customers located on Vancouver Island. As at December 31, 2004, the total amounts expended by BC Hydro on these two projects totalled approximately $100 million of which approximately $70 million relates to VIGP with the balance related to GSX. BC Hydro also financed spending totalling approximately $21 million (US$17 million) spent by the joint venture partner on GSX. As a result of its review, and to reflect uncertainties as to these projects proceeding or the costs being recovered, BC Hydro recorded a provision in fiscal 2004 for its share of the VIGP and GSX project costs and related project exposures.

BC Hydro completed the Vancouver Island Call for Tenders process. The Call for Tenders evaluated alternatives for providing additional supply to customers located on Vancouver Island including the potential use by third parties of the VIGP assets. As a result of the Call for Tenders, on November 3, 2004, BC Hydro announced that, subject to regulatory approval, it will offer an electricity purchase agreement (EPA) to Duke Point Power Limited Partnership (Duke Point Power). If regulatory approval is received, the Duke Point Power project would purchase certain of the VIGP assets and this would result in a significant recovery of the VIGP costs. BC Hydro has made application to the BCUC for approval of the EPA related to Duke Point Power. Regulatory Hearings related to the Call for Tenders process and the EPA with Duke Point Power started in January 2005, with a decision expected in February 2005.

On December 20, 2004, BC Hydro and its joint venture partner announced the cancellation of GSX, as it is no longer considered a competitive supply option. As a result, there will be no further expenditures on this project.

BC Hydro believes that the current provision related to VIGP and GSX fully provides for all exposures related to these projects, and will consider whether adjustments to the provision are required following the completion of the regulatory approval process. During fiscal 2005 the Commission approved a designated regulatory account with respect to the costs of VIGP and GSX. BC Hydro intends to seek recovery of the VIGP and GSX costs in future rates once the final status of these two projects is determined.

Note 9: Employee Future Benefits

BC Hydro's cost for employee future benefits for the three months ended December 31, 2004 was $19 million (2003–$19 million). The cost for employee future benefits for the nine months ended December 31, 2004 was $56 million (2003 – $58 million).

Note 10: Commitments and Contingencies

a) California Legal Contingencies

At December 31, 2004, Powerex was owed US$269 million (CDN$324 million) by the California Power Exchange (Cal Px) and the California Independent System Operator (Cal ISO) 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 Cal ISO were unable to pay these amounts to Powerex. In addition, certain California parties requested the Federal Energy Regulatory Commission (FERC) to consider whether refunds should be made to the Cal PX, the Cal ISO and the California Department of Water Resources by various suppliers, including Powerex.

Powerex has been named, along with other energy providers, as a defendant in a number of lawsuits and regulatory proceedings that allege 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. On September 9, 2004, the U.S. Ninth Circuit Court issued a ruling in the case Lockyer v. FERC. In its ruling, the court stated that the FERC "abused its administrative discretion by declining to order refunds for violations" of the agency's reporting rules under the Federal Power Act, and sent the case back to FERC for further consideration. The ruling may impact a number of issues previously decided by FERC, including Powerex's US$1.3 million FERC Settlement Agreement.

BC Hydro was also directly joined as a defendant in the California Consumer Class Action lawsuit. In response to an application by BC Hydro to be dismissed from the lawsuit, a U.S. Federal Court judge ruled that, except for Powerex, BC Hydro is immune from these claims in the United States by virtue of the Foreign Sovereign Immunity Act. The U.S. Court of Appeals for the Ninth Circuit upheld this finding, and removed BC Hydro from the lawsuit. The court also upheld the finding that Powerex does not enjoy foreign sovereign entity status and therefore remains a party to the lawsuit, which was remanded back to California State Court.

Due to the 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 and BC Hydro.

Management cannot predict whether the amounts owed by the Cal PX and Cal ISO are recoverable, or whether amounts may need to be refunded as a result of the FERC proceedings. BC Hydro 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 may differ materially 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 collection process.

b) Other

Due to the size, complexity and nature of BC Hydro's operations, various other legal matters are pending. It is not possible at this time to predict with any certainty the outcome of such litigation. Management believes that any settlement related to these matters will not have a material effect on BC Hydro's consolidated financial position or results of operations.

Columbia Basin Power Projects

On September 30, 2004, the BC Hydro Board of Directors approved in principle a proposal to acquire the assets of Columbia Power Corporation (CPC) and the Columbia Basin Trust Energy Inc. (CBT Energy). Both CPC and CBT Energy are subsidiaries of the Province.

CPC and CBT Energy jointly own hydroelectric facilities comprising two operating facilities, one under construction and one project in development.

On November 23, 2004, BC Hydro announced that it would suspend its due diligence related to this potential acquisition. This was based on the decision by the owner of CBT Energy that it was not comfortable moving forward with the proposed sale.

Other

There are no other material changes to the commitments and contingencies disclosed in the notes to BC Hydro's 2004 Annual Consolidated Financial Statements.

Note 11: Segmented Information

Three months ended December 31, 2004

(in millions)	Distribution $	Transmission $	Generation $	Powerex $	Other $	Consolidation Adjustments/ Eliminations $	Total $
External revenues	683	3	2	278	8	(4)[2]	970
Inter-segment revenues	192	151	256	130	62	(791)	–
Net income (loss)	233	30	(40)	192	(13)	(237)[2]	165

Three months ended December 31, 2003 (restated)[3]

(in millions)	Distribution $	Transmission $	Generation $	Powerex $	Other $	Consolidation Adjustments/ Eliminations $	Total $
External revenues	672	3	9	216	10	–	910
Inter-segment revenues	–	164	372	98	107	(741)	–
Net income (loss)	(87)	36	124	12	14	4[2]	103

Nine months ended December 31, 2004

(in millions)	Distribution $	Transmission $	Generation $	Powerex $	Other $	Consolidation Adjustments/ Eliminations $	Total $
External revenues	1,905	10	(2)	746	41	(14)[2]	2,686
Inter-segment revenues	280	461	1,026	448	257	(2,472)	–
Net income (loss)	222	84	58	280	(11)	(324)[2]	309
Total assets	3,609	3,022	4,608	1,009	26[1]	(303)	11,971

Nine months ended December 31, 2003 (restated)[3]

(in millions)	Distribution $	Transmission $	Generation $	Powerex $	Other $	Consolidation Adjustments/ Eliminations $	Total $
External revenues	1,792	9	13	703	31	(8)[2]	2,540
Inter-segment revenues	–	495	1,060	341	308	(2,204)	–
Net income (loss)	(208)	118	296	106	22	(112)	142
Total assets	3,401	3,101	4,794	440	454[1]	(402)	11,788

1 Mainly consists of capital assets such as office buildings, vehicles and computer equipment.

2 These adjustments mainly relate to the difference between BC Hydro's management reporting, used for risk management and performance measurement purposes, and Canadian GAAP. For management reporting purposes, energy purchases bought for future resale are expensed when the energy is sold. The energy purchased for future resale is also marked to market each month. For GAAP reporting purposes, energy purchases bought for future resale are expensed in the period of purchase.

3 Restated for retroactive application of the asset retirement obligations accounting standard (Note 4).

4. Lines of Business Performance

GENERATION

Cost of Heritage Electricity ($/MWh) ▼

Annual Target – $25.60/MWh

	Actual	Target
Excluding Return on Equity		
Q3 04/05	$21.66	$19.93
Including Return on Equity*		
Q3 04/05	$25.74	$24.10

*as defined in the Heritage Special Directive No. HC-2

For the third quarter, the cost of Heritage Electricity was higher than target. This was due to higher-than-planned energy purchases (365 GWh greater than plan) and thermal generation (114 GWh greater than plan). These increased purchases met the increased Distribution requirement (295 GWh) and compensated for the reduced hydro generation. The average cost of purchases was about $6/MWh higher than plan. Purchases were made to support reservoir levels for the current and next fiscal year.

Commercial Performance ▲

Annual Target – 99.50%

	Actual	Target
Q3 04/05	99.88%	99.50%

Equipment reliability and availability tracked better than target for the third quarter and has performed better than target for the year-to-date due primarily to the implementation of reliability-centred maintenance practices.

Average Number of Forced Outages ▲

Annual Target – 3.2

	Actual	Target
Q3 04/05	0.54	0.8

Relative to the target, equipment is operating more reliably than planned on an annualized basis. Results are also below the best results achieved for the previous four years for all regions and classes of plants. The downward trend reflects the benefits of implementing reliability-centred maintenance practices.

Resource Smart Energy Gains Put into Service (GWh) ●

Annual Target – 104 GWh

	Actual	Target
Q3 04/05	81	81

The turbine runner upgrade at G.M. Shrum Unit 8 was completed and the unit was returned to service on November 26, 2004.

DISTRIBUTION

COMA / Customer ▼

(Capital and OMA cost per customer– dollars)

Annual Target – $265.20

	Actual	Target
Q3 04/05	$71.30	$66.70
Q3 03/04	$69.40	N/A

The actual COMA cost per customer was higher than target, due to increased capital work driven by higher-than-expected customer growth.

Customer-Based Generation GWh ▼

Annual Target – 275 GWh

	Actual	Target
YTD Q3 04/05	259	275
YTD Q3 03/04	50	N/A

Customer-Based Generation was below target for the third quarter. No quarterly target is set for this measure because it is based on customer response to BC Hydro's acquisition process. An annual target is set based on an estimate of when projects for contracted energy are scheduled to come online. Two Customer-Based Generation projects are online. This measure will remain below target at year-end because one of the three projects scheduled to come online was cancelled.

Green Gigawatt Hours ●

Annual Target – 756 GWh

	Actual	Target
YTD Q3 04/05	735	756
YTD Q2 03/04	120	N/A

Green Gigawatt Hours is on target through the third quarter. The target shown is annual. No quarterly target is set for this measure because it is based on customer response to three acquisition processes. An annual target is set based on an estimate of when projects for contracted energy are scheduled to come online. Thirteen projects forecast are online. The target will not be met at year-end because six of the Green IPP projects that were scheduled to come online were delayed beyond fiscal 2005.

Customer Care ●

Accenture Business Services for Utilities (ABSU) is responsible for the performance of all Customer Care functions. There are 13 critical service levels, which are measures of this performance. For the third quarter, 11 of these measures have been met or exceeded and two were still under review and not being reported.

Customer satisfaction with Call Centre transactions is measured by a survey of residential and commercial customers who have completed a recent transaction with the Call Centres. This telephone survey is conducted by an independent third party on a weekly basis and the results aggregated for the month. The satisfaction level for the third quarter met the target of 84 per cent.

ENGINEERING SERVICES

Utilization Rate ●

Annual target – 83%

	Actual	Target
Q3 04/05	83%	83%

The Utilization Rate for the third quarter was on target.

Hourly Charge-out Rate ▲

Annual target – $97

	Actual	Target
Q3 04/05	$96	$97

The Hourly Charge-out Rate for the third quarter was above target. For this measure, a lower actual result is better.

% of Approved EIT and GTT Positions Filled ●

Annual target – 100%

	Actual	Target
Q3 04/05	100%	100%

Percentage of EIT and GTT Positions Filled was on target for the third quarter.

FIELD SERVICES

All Injury Frequency ▲

	Actual	Target	Prior Year
Q3 04/05	4.1	4.7	4.6

The All Injury Frequency was significantly better than target for the third quarter, primarily as a result of continued employee and management emphasis on safety.

Utilization Rate ●

	Actual	Target	Prior Year
Q3 04/05	74.3%	75.5%	74.7%

The Utilization Rate for the third quarter was on target (defined as within five per cent of the target).

Hourly Charge-out Rate ▲

	Actual	Target	Prior Year
Q3 04/05	$90	$95	$96

The Hourly Charge-Out Rate for the third quarter was better than target (lower is better), as the Construction Business Unit, which traditionally charges out at lower rates, contributed significantly more than planned to the increased chargeable hours.

% Of Total Planned Work Completed ●

	Actual	Target	Prior Year
Q3 04/05	100 %	100%	100%

This measure is a proxy measure of customer satisfaction. High levels of completed work have historically correlated to high levels of customer satisfaction. Targets have been set based on customer expectations. Performance was on target for the third quarter.

Total Trainees – Strategic Workforce Planning ●

	Actual	Target	Prior Year
Q3 04/05	125	133	99

Field Services continues to invest in building a highly skilled workforce, with trainees accounting for nearly 10 per cent of the regular employee base. Strategic Workforce Planning (SWfP) is defined as the number of apprentices/trainees in Field Services who are being trained to fill positions as a result of retirement, attrition or other core workforce requirements.

The interviewing process has been completed, and offers have been made, for nine SWfP managers. On November 8 the first of the fiscal 2005 SWfP managers started work. The total number of SWfP hires to date for fiscal 2005 is 25 (annual revised target is 33). It is anticipated that approximately 133 apprentices/trainees will be on the system by fiscal year-end.

POWEREX

Transactions per Employee ▲

Annual target – 660

	Actual	Target
Q3 04/05	269	165

Powerex's third quarter TPE is 269, compared with plan of 165. The variance is largely attributable to an increase in Real-Time transactions in the Southwest, as a result of the implementation of California market design changes on October 1, 2004. Powerex expects to meet its annual TPE target of 660.

5. British Columbia Transmission Corporation Performance

Transmission Utilization Ratio ▼

	Actual	Target
Q3 04/05	63%	65%

The Utilization Rate was slightly lower than target, reflecting lower market demand for transmission service.

SAIDI
(System Average Interruption Duration Index) ▲

	Actual	Target
Q3 04/05	2.0	2.2

The SAIDI result for the third quarter was ahead of target.

NERC/WECC Compliance ▼

	Actual	Target
Q3 04/05	1 violation	Full Compliance

NERC/WECC compliance was slightly lower than target for the third quarter.

One minor violation was reported in October 2004. This was the result of a small unscheduled flow relief for 1.7 MW, arising from a software/training deficiency, which has since been rectified.

Number of Preventable Lost Time Accidents ●

	Actual	Target
Q3 04/05	0	0

The third-quarter results were on target.

Number of Preventable and Reportable Environmental Incidents ●

	Actual	Target
Q3 04/05	0	2 per year

There were no incidents in the third quarter. The year-to-date result of two incidents is on target.

Completion of Planned Safety and Environment Management Programs ▲

	Actual	Target
Q3 04/05	94%	85%

* Target: 85% of planned activities completed for the year.

BCTC is implementing new safety management and environmental management systems. This measure records managerial progress in completing the annual calendar of system actions designed to manage environmental and safety risks and drive continuous improvement. The third-quarter results were ahead of target.

Glossary for Performance Measures

All Injury Frequency (AIF) is defined as the total number of employee injuries (Medical Aids and Disabling Injuries), relative to the number of worked hours in the same period. For this measurement, Medical Aid injuries are defined as those where a professional medical practitioner has rendered services beyond the level defined as "first aid" in relation to the injury incident, and the employee was not absent from work beyond time lost on the day of the injury. Disabling injuries are defined as those that involve the employee being absent from work beyond the day of the injury.

Approved Strategic Workforce Positions Filled is defined as the number of positions filled under BC Hydro's Strategic Workforce Planning (SWfP) initiative. SWfP is the management process for anticipating, scoping and planning the alignment of needed critical workforce capabilities to meet BC Hydro's strategic business goals. The targets were set based on internally performed needs assessments.

A preventable lost-time accident is one in which BCTC and its employees failed to foresee a risk and act to avoid an accident.

Average number of Forced Outages per unit (count) is defined as the total number of forced outages divided by the total number of units.

COMA/Customer is defined as gross recurring capital expenditures (net of Telus recoveries) and operations, maintenance and administrative expenses divided by the total number of customers. BC Hydro's Distribution Line of Business includes a number of functions that are not included in industry benchmarks. The PA Consulting and Canadian Electricity Association benchmarks are based only on the expenditures associated with the distribution of electricity.

Commercial Performance is defined as revenue from energy produced relative to the revenue from energy that could have been produced had all generation needed to meet domestic load and trade opportunities been available. The annual target is based on historical performance (including analysis of planned outages) and assessment of reasonable improvement given investment in assets.

Conservation Gigawatt Hours is defined as the rate at which annual gigawatt hours are being saved as a result of economic demand-side management (conservation, energy efficiency, and load displacement). The targets are based on net savings from current demand-side management programs and programs expected to come onstream. The targets include both residential and business demand-side management.

Cost of Heritage Electricity (or Cost per MWh including Electricity Purchases) is defined as all Generation costs, including the cost of electricity purchases, divided by the actual volume of energy supplied to Distribution. It provides an indication of Generation's efficiency of producing and purchasing electricity.

Customer-Based Generation GWh is defined as gigawatt hours from customer-based sources (industrial or large commercial customers) that meet purchase price limits. Targets have been set to align with the Government objective of 50 per cent of new electricity supply from clean energy sources.

Environmental Regulatory Compliance (ERC) is defined as the number of externally reportable, preventable environmental incidents. For this type of measure there is an inherent risk of unreported incidents. BC Hydro is reviewing its controls to attempt to ensure that all applicable incidents are reported.

Green Gigawatt Hours is defined as gigawatt hours contracted from green sources that meet purchase price limits. A green source of energy must be renewable, licensable and socially responsible and have low environmental impact. Targets have been set to align with the Government objective of 50 per cent of new electricity supply from clean energy sources.

Hourly Charge-out Rate (Engineering) is defined as the weighted average hourly rate charged by Engineering Services. It is calculated as net revenue less the contract hire margin divided by total billable hours. Targets have been set based on improvements to historical performance.

GLOSSARY CONTINUED

Hourly Charge-out Rate (Field Services/CBU) is defined as the average hourly billing rate designed to recover all costs providing the service. Targets have been set based on expected efficiency gains and external benchmarks. This is a blended Field Services/Construction Business Unit rate.

Labour Utilization (Field Services/CBU) is defined as the number of chargeable hours divided by the total of all labour hours available. Targets have been set based on improvements to historical performance. Standby is not currently included in this measure but is being addressed as part of the Field Services pricing and service level agreement process. This is a blended Field Services/Construction Business Unit (CBU) rate.

NERC/WECC Compliance is defined as compliance with reliability standards established by the WECC and the security standards established by NERC.

Percentage of Approved Engineer-in-Training (EIT) and Graduate Technologist-in-Training (GTT) Positions Filled is defined as the percentage of EIT and GTT targeted positions that are filled. The targets have been set based on an internal needs assessment against expected organizational capacity.

Percentage of Total Planned Work Completed is defined as the total planned customer work assigned to Field Services divided by total planned customer work completed.

Reliability is defined in terms of Average System Availability Index (ASAI) and Customer Average Interruption Duration Index (CAIDI). ASAI is the percentage of time power is available. CAIDI is the average number of hours per interruption.

Resource Smart Energy Gains Put into Service is defined as the projected, long-term average incremental energy gains from existing Generation facilities, that are put into service.

SAIDI is a statistical measure of transmission related outages caused by unforeseen events such as equipment failure or weather-related outages based on a rolling 12-month average.

Transactions per Employee (TPE) is defined as the number of transactions conducted by Powerex, divided by the number of Powerex employees.

Transmission Utilization Ratio is defined as the ratio of total transmission capacity sold to total transfer capability. This measures how much of the transmission grid's capacity is actually sold to customers, generating additional revenue. This measure is based on a rolling 12-month average.

Utilization Rate (Engineering) is defined as billable hours divided by total hours worked. Targets have been set based on moving towards first-quartile (top 25 per cent) when compared with other engineering firms.