EPCOR Utilities Inc.
Management's Discussion and Analysis
December 31, 2011

This management's discussion and analysis (MD&A) dated March 16, 2012 should be read in conjunction with the audited consolidated financial statements of EPCOR Utilities Inc. and its subsidiaries for the years ended December 31, 2011 and 2010 and the cautionary statement regarding forward-looking information on pages 54 and 55 of this MD&A. In this MD&A, any reference to "the Company", "EPCOR", "it", "its", "we", "our" or "us", except where otherwise noted or the context otherwise indicates, means EPCOR Utilities Inc., together with its subsidiaries. In this MD&A, Capital Power refers to Capital Power Corporation and its directly and indirectly owned subsidiaries including Capital Power L.P., except where otherwise noted or the context otherwise requires. Financial information in this MD&A is based on the audited consolidated financial statements, which were prepared in accordance with International Financial Reporting Standards (IFRS), and is presented in Canadian dollars unless otherwise specified. In accordance with its terms of reference, the Audit Committee of the Company's Board of Directors reviews the contents of the MD&A and recommends its approval by the Board of Directors. The Board of Directors has approved this MD&A.

OVERVIEW

EPCOR is wholly-owned by The City of Edmonton (the City). EPCOR builds, owns and operates electrical transmission and distribution networks in Canada as well as water and wastewater treatment facilities and infrastructure in Canada and the United States (U.S.). EPCOR also provides electricity and water services and products to residential and commercial customers. EPCOR's electricity (collectively the Distribution and Transmission and Energy Services segments) and water (including wastewater treatment) businesses consist primarily of rate-regulated and long-term commercial contracted operations. EPCOR's continuous improvement objective is to seek out ways of maximizing the efficiency of its electricity and water operations.

Net income for the year ended December 31, 2011 was $144 million compared with $105 million for 2010. The results for 2011 were higher than 2010 primarily due to increased net income from distribution and transmission, a positive fair value adjustment on foreign exchange forward contracts, increased equity income from Capital Power, and a lower loss on sale of a portion of EPCOR's investment in Capital Power in 2011 than in 2010. These increases were partially offset by lower net income from water and wastewater operations and a negative fair value adjustment, at December 31, 2011, on financial electricity purchase contracts. Net income from EPCOR's core operations increased $8 million compared with 2010, as more fully described below under Analysis of Net Income. EPCOR's core operations performed well in the year without any significant issues or disruptions to customers.

Significant events for 2011 were as follows:

- The Company received regulatory approvals for its acquisition of Arizona-American Water Company (Arizona Water) and New Mexico-American Water Company, Inc., (New Mexico Water).
- The Company's investment in Capital Power was further reduced.
- The Company received approval from the Alberta Utilities Commission (AUC) for the Heartland Transmission project.

- The Company received approval for its five-year Performance Based Regulation Plan renewal application in respect of its Edmonton water treatment and distribution services and wastewater treatment services, effective April 1, 2012.
- The Company acquired 100% of the common shares of Chaparral City Water Company (Chaparral).
- The Company received approval for Energy Services' new Energy Price Setting Plan (EPSP), which took effect on July 1, 2011.
- The Company moved into its new offices in downtown Edmonton in the fourth quarter of 2011.

Each of these transactions noted above are discussed further under Significant Events below.

STRATEGY

EPCOR's vision is to become a premier essential services utility in North America. To achieve this vision, EPCOR must excel at its electricity and water operations and be successful in its pursuit of new business growth opportunities. EPCOR's electricity strategy includes: (i) developing electricity transmission projects; (ii) acquiring rate-regulated electricity transmission and distribution assets; and (iii) providing new services and products to customers. EPCOR's water strategy is to focus on: (i) developing municipal infrastructure; (ii) providing design, build, finance and operating services for water and wastewater treatment and water distribution infrastructure; (iii) providing potable and process water and wastewater treatment for industrial customers; and (iv) acquiring rate-regulated assets and operations outside of Alberta. Subject to acceptable business risk and the availability of financing, EPCOR intends to increase net income and shareholder value by growing its portfolio of electricity and water assets in rate-regulated and competitive contracted businesses.

We believe the long-term outlook for the North American electricity and water and wastewater treatment businesses remains relatively strong. While the recent recession and slow recovery has constrained electricity demand in the short-term, economic recovery will require new electricity transmission and distribution capacity in Alberta and other jurisdictions. In addition, the Alberta Electric System Operator (AESO) has outlined in their 2009 Long-term Transmission System plan a significant growth strategy for Alberta's transmission infrastructure over the upcoming 10 years which may provide us with an opportunity to further expand our investment in electricity transmission infrastructure. Similarly, the demand for water and wastewater infrastructure in North America is also expected to increase due to population growth, aging infrastructure, reduced water supply and increased consumer expectations for high quality and safe water.

Over the next five years, we will focus on investment opportunities in essential infrastructure in the water, wastewater and electricity sectors, including commercially contracted and rate-regulated facilities. We expect our rate-regulated business investment opportunities to be in water and wastewater infrastructure upgrades, acquisition of water and wastewater infrastructure businesses outside of Alberta, electricity transmission infrastructure development, and electricity distribution system upgrades. We will only invest in new electricity or water and wastewater treatment assets where appropriate returns are expected, cost effective financing is available and the environmental footprint is acceptable. We plan to continue to increase our operating efficiency. We will also be monitoring our investment in Capital Power and seek opportunities or transactions to reduce the investment, depending on our demand for capital and the prevailing market conditions.

As a utility with rate-regulated and contracted operations, an investment grade credit rating and access to capital through new and existing credit facilities and public debt financing, EPCOR believes it is able to adapt to changes in economic conditions. We also recognize that we are not immune to recessionary trends and will remain vigilant to minimize the risk of taking on projects that would result in growth beyond our financial means.

KEY PERFORMANCE INDICATORS

Our performance in meeting the goals of our strategy is measured through financial and non-financial measures that are approved by the Board of Directors. The measures fall under four broad categories comprised of people, growth (financial), operational excellence and the environment, and are applied across the Company.

There are specific measures established for each business unit and corporate shared service unit in alignment with the Company's strategy. For example, under the people category, safety performance is measured based on the number of incidents or reportable injury frequency. In the customer service area of Energy Services, a key operational excellence measure relates to call answer times and billing accuracy. Business unit measures under the customer category are focused on customer related measures relevant to the particular business unit, such as customer satisfaction or reputation survey results. Environmental measures for business units typically include reportable incident frequency.

In 2011, EPCOR's financial results from core operations did not meet our plan primarily due to lower customer water consumption as a result of weather conditions and customers' application of water efficiency measures. Due to severe and unusual weather conditions at the beginning of 2011, we experienced a high number of safety related incidents and as a result, we missed our safety targets for 2011. This prompted a review of the Company's cold weather work practices and several controls have been implemented to improve safety during adverse weather conditions. We continued to strive to reinforce a zero injury and occupational illness culture. Segment performance measures are also discussed under Segment Results of this MD&A.

SIGNIFICANT EVENTS

Acquisition of Arizona Water and New Mexico Water

In January 2011, EPCOR entered into an agreement to acquire 100% of the outstanding stock of Arizona Water and New Mexico Water for $460 million (US$461 million), including the assumption of $9 million (US$9 million) of debt, subject to certain adjustments. In the fourth quarter of 2011, the Company received regulatory approval for the purchase from the Arizona Corporation Commission and New Mexico Public Regulation Commission. The acquisition was completed on January 31, 2012, with EPCOR assuming operations of Arizona Water and New Mexico Water on February 1, 2012.

Heartland Transmission Project

On November 1, 2011, the AUC announced its approval of the Heartland Transmission project, which includes the construction of a 500 kilovolt (kV) double-circuit overhead electricity transmission line to reinforce the existing 500 kV electricity transmission system in the Edmonton area and extend it to the Industrial Heartland area near Fort Saskatchewan, Alberta. The transmission line will be jointly owned by EPCOR and AltaLink L.P.

Investment in Capital Power

The Company's economic interest in Capital Power was reduced to 39% (2010 – 61%) as a result of the Company selling a portion of its investment in Capital Power in the fourth quarter of 2011 and also by virtue of dilutions resulting from the issuances of common shares by Capital Power during the year. The Company incurred net losses of $24 million (before income tax recovery) in 2011 as a result of these transactions.

A portion of the proceeds from the sale were used to pay down short-term debt with the remainder used as part of the financing of the Arizona Water and New Mexico Water acquisition.

2012 - 2016 Edmonton Water and Wastewater Rates Application Decision

In October 2011, Edmonton City Council approved the renewal of Water Services' Performance Based Regulation Plan under which the Company's Edmonton water treatment and distribution services and wastewater treatment services will operate for five years commencing April 1, 2012.

Chaparral Acquisition

On May 31, 2011, the Company acquired 100% of the common shares of Chaparral from American States Water Company for total consideration of US$30 million in cash plus the assumption of US$5 million in long-term debt. EPCOR assumed control of the operations on June 1, 2011. Chaparral is a public utility company engaged principally in the purchase, production, distribution and sale of water to approximately 13,000 customers in the Town of Fountain Hills, Arizona and a small area east of Scottsdale, Arizona.

Energy Price Setting Plan

In March 2011, the AUC approved Energy Services' new EPSP which took effect on July 1, 2011. In May 2011, as part of the new EPSP, Energy Services commenced directly managing its electricity procurement requirements where they were outsourced under the previous EPSP.

Move into New Offices

In the fourth quarter of 2011, the Company moved into its new corporate offices. The move involved relocating over 700 employees and contractors and the Company's data center to the new offices in four stages, without any business interruption. The new offices house all of the Company's corporate and Energy Services employees in addition to some of its Water Services employees.

Note on Comparisons

In the first quarter of 2011, EPCOR began reporting its financial results under IFRS, as mandated by the Canadian Institute of Chartered Accountants (CICA). The Company prepared its December 31, 2011 consolidated financial statements in accordance with IFRS, which includes presenting the comparative net income results for December 31, 2010 in accordance with IFRS (see Adoption of International Financial Reporting Standards below). All comparative figures in the tables and discussion in this MD&A have been converted to IFRS with the exception of certain amounts specifically noted as being presented in accordance with previous Canadian generally accepted accounting principles (CGAAP).

CONSOLIDATED FINANCIAL INFORMATION

Years ended December 31,	**2011**	**2010**	**2009**
($ millions)	IFRS	IFRS	CGAAP
Net income	$ 144	$ 105	$ 125
Revenue	1,794	1,437	2,354

Years ended December 31,	**2011**	**2010**	**2009**
($ millions)	IFRS	IFRS	IFRS
Total assets	$ 5,032	$ 4,932	$ 5,154
Loans and borrowings (including current portion)	1,699	1,672	1,912
Common share dividends	138	136	134

Analysis of Net Income

($ millions)

Net income for the year ended December 31, 2009 (under CGAAP)	**$**	**125**
Loss on sale of power generation business		130
Net income related to the power generation business that was sold effective July 2009		(143)
Loss on sale of a portion of investment in Capital Power		(33)
Higher equity income from Capital Power (net of income tax expense)		15
		94
Higher Distribution and Transmission operating income		19
Higher Energy Services operating income		10
Higher fair value of floating-rate notes		7
Higher commercial water operating income		6
Higher Gold Bar operating income		6
Lower Edmonton water operating income		(3)
Other		(6)
Increase in earnings from core operations		39
Net income for the year ended December 31, 2010 (under CGAAP)	**$**	**133**

Net income for the year ended December 31, 2010 (under CGAAP)	**$**	**133**
IFRS adjustments (see page 42)		(28)
Net income for the year ended December 31, 2010 (under IFRS)		**105**
Higher equity income from Capital Power		35
Higher loss on sale of a portion of and net gain on dilutions of investment in Capital Power (net of income tax recovery)		(4)
		136
Higher Distribution and Transmission operating income		16
Fair value adjustment on foreign exchange forward contracts		10
Lower net financing expenses		6
Higher U.S. water operating income		1
Lower commercial water services margin		(4)
Higher Energy Services operating income excluding fair value adjustments		4
Fair value adjustments on financial electricity purchase contracts		(10)
Lower Edmonton water and wastewater margins		(10)
Other		(5)
Increase in earnings from core operations		8
Net income for the year ended December 31, 2011 (under IFRS)	**$**	**144**

Net income for the year ended December 31, 2011 was $144 million compared with $105 million for 2010. Explanations of the primary year-over-year variances are as follows:

- EPCOR's equity share of income of Capital Power was higher in 2011 compared with 2010. The change reflects the Company's equity share of Capital Power's gain on sale of a subsidiary in 2011, partially offset by the impact of EPCOR's reduced economic interest in Capital Power.
- The Company sold portions of its investment in Capital Power in 2011 and in 2010, incurring losses on each sale. In addition, the Company incurred losses on dilutions of its investment in Capital Power by virtue of common share issuances by Capital Power during 2011 with no corresponding losses in 2010. Losses on sale resulted from the carrying amount of the portion of our investment in Capital Power that was sold being greater than the consideration received less direct expenses and realized accumulated other comprehensive loss. The loss on sale incurred in 2011 was higher than the loss on sale incurred in 2010 primarily due to a higher share price and higher carrying amount of the investment on a per share basis in 2011 than in 2010. Losses on dilutions resulted from the carrying amount of the portion of our investment which is considered to be disposed of as a result of dilution being greater than the portion of proceeds on the issuance deemed to be attributed to the Company.
- Distribution and Transmission's operating income was higher in 2011 compared with 2010 primarily due to increased electricity distribution and transmission tariff rates, partially offset by increased costs charged by the electric system operator in 2011.
- Fair value adjustment on foreign exchange forward contracts reflects the difference between the Canada / U.S. exchange rate at December 31, 2011 and the forward exchange rate on U.S. dollar contracts which were entered into to manage the foreign exchange risk related to financing the acquisition of Arizona Water and New Mexico Water.
- Net financing expenses were lower in 2011 compared with 2010 primarily due to lower average debt levels, partially offset by lower earnings of the sinking fund associated with certain long-term debt.
- U.S. water operating income for 2011 represents operating results of newly acquired Chaparral operations, with no corresponding income in 2010.
- Margins from commercial water services activities outside of Edmonton for 2011 were lower compared with 2010 primarily due to the termination of a commercial municipal water contract in September 2010, lower commercial water construction activity in 2011 compared with 2010, and acquisition and integration expenses relating to Chaparral, Arizona Water and New Mexico Water, partially offset by income from a full year of additional water and wastewater treatment plant operations in the Alberta oil sands energy sector acquired in late 2010.
- Energy Services operating income, excluding fair value adjustments on financial electricity purchase contracts, was higher in 2011 compared with 2010 primarily due to higher rates related to customer care services provided to regulated customers, partially offset by lower commercial services margins due to lower customer site counts.
- We recorded fair value adjustments on financial electricity purchase contracts for 2011 associated with our EPSP. Under the EPSP, we enter into short-term financial electricity purchase contracts up to 45 days in advance of customers' consumption of the electricity in order to fix the price of electricity for that month. These contracts are recorded at fair value and if the market price of electricity (as measured by the forward index price) is less than the embedded

price in the financial contract at the reporting date, there will be a loss on the adjustment to fair value. Conversely, there will be a gain if the market price is higher than the embedded financial contract price. The fair value adjustments do not impact the fundamental economics of the EPSP.

- Margins from Edmonton water and wastewater treatment utilities for 2011 were lower compared with 2010 primarily due to lower water consumption and related lower wastewater volumes, a provision related to a decision with respect to a Regional Water Customer Group rate complaint hearing, higher chemical costs due to poorer raw water quality, and higher labor and power costs than reflected in approved customer rates.

Revenues

($ millions)

Revenues for the year ended December 31, 2009 (under CGAAP)	**$**	**2,354**
Decreases related to the power generation business that was sold July 2009		(976)
		1,378
Higher electricity distribution and transmission tariff revenues		48
Higher interest revenue		21
Higher Gold Bar wastewater treatment revenues		12
Higher commercial water operations revenues		10
Higher transportation services revenues		8
Higher retail regulated rate tariff electricity revenues		7
Lower Edmonton water sales volumes, partially offset by higher customer rates		(6)
Other		(5)
Increase in revenues from core operations		95
Revenues for the year ended December 31, 2010 (under CGAAP)	**$**	**1,473**

Revenues for the year ended December 31, 2010 (under CGAAP)	**$**	**1,473**
IFRS adjustments (see page 42)		16
Less other income presented separately under IFRS		(52)
Revenues for the year ended December 31, 2010 (under IFRS)		**1,437**
Higher retail regulated rate tariff electricity revenues		295
Higher electricity distribution and transmission tariff revenues		46
Higher transportation services revenues		18
Higher U.S. water operations revenues		6
Lower commercial water operations revenues		(4)
Other		(4)
Increase in revenues from core operations		357
Revenues for the year ended December 31, 2011 (under IFRS)	**$**	**1,794**

Consolidated revenues for the year ended December 31, 2011 increased $357 million compared with 2010 primarily due to the net impact of the following year-over-year changes:

- Retail Regulated Rate Tariff (RRT) electricity revenues were higher in 2011 compared with 2010 primarily due to higher customer RRT rates and higher electricity sales volumes in 2011.
- Electricity distribution and transmission tariff revenues were higher in 2011 compared with 2010 primarily due to higher approved customer rates and higher system access revenues. The higher system access revenues were due to improved timing of approvals to bill and collect electricity transmission flow-through costs from customers than what was experienced in the past.

- Transportation services activity, which is performed by the Technologies unit of the Distribution and Transmission segment, was higher in 2011 compared with 2010 primarily due to increased activity under an agreement with the City.
- U.S. water operations revenues for 2011 represent water sales of Chaparral operations acquired in the second quarter of 2011.
- Commercial water revenues were lower in 2011 primarily as a result of termination of a commercial municipal water contract in September 2010 and lower construction work performed for our Alberta oil sands energy sector and southern Alberta customers compared with 2010, partially offset by revenue from a full year of additional water and wastewater treatment plant operations in the Alberta oil sands energy sector acquired in late 2010.

Capital Spending and Investment

Years ended December 31, ($ millions)	**2011** IFRS	**2010** IFRS	**2009** CGAAP
Water Services	$ 108	$ 108	$ 183
Distribution and Transmission	188	129	90
Energy Services	1	-	8
Corporate	41	8	8
	338	245	289
Chaparral acquisition	29	1	-
Generation	-	-	228
	$ 367	**$ 246**	**$ 517**

In 2011, we continued to enhance and increase the capacity of our infrastructure assets to improve reliability and meet increasing electricity and treated water and wastewater volumes. Capital expenditures for property, plant and equipment (PP&E) and other assets were higher for 2011 compared with 2010. Increased construction activity on the new corporate office leasehold improvements in EPCOR Tower and Distribution and Transmission's North Light Rail Transit Extension, Poundmaker Electricity Distribution Substation and Heartland Transmission projects was partially offset by decreased acquisition expenditures in Water Services in 2011. Capital spending includes EPCOR's 50% joint venture share of the Heartland Transmission project's capital expenditures.

Work on a number of significant projects which commenced in 2011, including the Poundmaker Electricity Distribution Substation project in northwest Edmonton and the Heartland Transmission project, will continue in 2012.

SEGMENT RESULTS

Water Services

Water Services earns income primarily from the treatment, distribution and sale of water and the treatment of wastewater while ensuring public health standards are exceeded. The majority of Water Services' income is earned through a performance based rate tariff charged to its Edmonton customers. The tariff is intended to allow Water Services to recover its costs and earn a fair rate of return while providing an incentive to manage costs below the inflationary adjustment built into the performance based rate. On June 1, 2011, Water Services commenced operations in Arizona after acquiring Chaparral. Chaparral's customer rates are subject to approval by the Arizona Corporation Commission and are intended to allow EPCOR to recover costs and earn a reasonable rate of return. The key to maintaining earnings on water sales is to provide sufficient quantities of high quality water while controlling costs. The key to maintaining earnings on wastewater treatment services is to ensure that quality wastewater operating practices are employed and that the associated infrastructure is maintained while controlling costs.

In addition, Water Services provides competitive contract-based water and wastewater services, including financing, in certain arrangements, to commercial, industrial and municipal customers. The key to earning satisfactory operating margins on these contracts is to satisfy the terms of the contracts while controlling or reducing operating costs.

Water Services Operating Income

Years ended December 31,			**2011**		**2010** restated*
(including intersegment transactions, $ millions)					
Revenues	Canadian water and wastewater sales	$	210	$	210
	Commercial and other		96		100
	U.S. water sales		6		-
			312		310
Expenses	Other raw materials and operating charges		82		82
	Staff costs and employee benefits		85		75
	Depreciation and amortization		41		38
	Franchise fees and property taxes		16		16
	Other administrative expenses		11		10
	Foreign exchange loss		1		-
			236		221
Operating income before corporate charges			76		89
Corporate charges			24		25
Operating income		**$**	**52**	**$**	**64**

Operating income for the year ended December 31, 2010	**$**	**64**
U.S. water operating income		2
Lower commercial water services margin		(4)
Lower Edmonton water and wastewater operating income		(12)
Other		2
Decrease in operating income		(12)
Operating income for the year ended December 31, 2011	**$**	**52**

* Water Services' operating income for 2010 was restated reflecting the transfer of the management of Technologies from Water Services to Distribution and Transmission.

For the year ended December 31, 2011, Water Services' operating income decreased by $12 million compared with 2010 due to the net impact of the following items:

- U.S. water operating income for 2011 represents operating results of newly acquired Chaparral operations with no corresponding income in 2010.
- Commercial water operating income was lower in 2011 compared with 2010 primarily due to acquisition and integration expenses relating to Chaparral, Arizona Water and New Mexico Water, as well as higher staffing, maintenance and power costs and lower commercial water revenues in 2011.
- Edmonton water and wastewater operating income was lower in 2011 compared with 2010 due to a provision related to a decision with respect to the Regional Water Customer Group rate complaint, lower Edmonton and area customer water consumption and related wastewater

volumes, and higher chemical and labor costs in excess of amounts recovered through increased customer rates. High snowpack and extended spring run-off as well as higher precipitation resulted in higher levels of silt (turbidity) in the North Saskatchewan River, requiring more chemical treatment and therefore higher chemical costs.

Years ended December 31,	**2011**	**2010**
Water volumes (megalitres)		
Water sales for Edmonton and surrounding region	121,700	121,739
Water sales for Arizona	4,263	-

Water Services owns nine, and operates 19 other water treatment and / or distribution facilities in Alberta, British Columbia and Arizona, U.S. Additionally, Water Services owns five wastewater treatment and / or collection facilities and operates 21 other wastewater treatment and / or collection facilities in Alberta and British Columbia. In 2011, Water Services continued construction and upgrade work on its water and wastewater facilities located in the Alberta oil sands region. Water Services' core market is stable as Water Services is the sole supplier of water and provider of wastewater services within Edmonton. Operationally, the facilities Water Services owns or manages performed according to plan in 2011.

Water Services focused on two key areas in 2011: (i) the upgrade and enhancement of water distribution infrastructure and wastewater treatment facilities within Edmonton; and (ii) the pursuit of growth opportunities outside of Alberta. Work on several significant upgrade projects within Edmonton continued in 2011, including a water main renewal program to improve Edmonton's water distribution system, a dechlorination project at the Rossdale water treatment plant to remove chlorine from water prior to discharge into the North Saskatchewan River and a plant heating project at the Gold Bar wastewater treatment facility, which included the construction of a new boiler house required to meet the increased demands of two new digesters commissioned in 2011. Work on the water main renewal program will continue in 2012. Water Services completed the Chaparral acquisition in the second quarter of 2011. In addition, in 2011, Water Services substantially completed preparations to close the acquisition of Arizona Water and New Mexico Water in January 2012. Water Services has also been actively pursuing additional growth opportunities in the Alberta oil sands energy sector.

Distribution and Transmission

Distribution and Transmission earns income principally by transmitting high-voltage electricity from power generation plants across the Alberta Interconnected Electrical System to points of distribution and, from there, distributing low-voltage electricity to retailers' end-use customers. Distribution and Transmission's assets are located in and around Edmonton and are regulated by the AUC. Distribution and Transmission charges regulated distribution and transmission tariffs intended to allow recovery of prudent costs and earn a fair rate of return on the electricity distribution and transmission infrastructure. Distribution and Transmission is also responsible for providing meter reading and load settlement services for all retail electricity suppliers within the Edmonton service area. EPCOR's Technologies business, which is managed by Distribution and Transmission, provides competitive contract-based commercial services related to installation, maintenance and repair of street lighting, traffic signals and light rail transit, primarily to the City.

Distribution and Transmission Operating Income

Years ended December 31,			2011		2010 restated*
(including intersegment transactions, $ millions)					
Revenues	Distribution	$	322	$	252
	Transmission		62		52
	Commercial and other		98		84
			482		388
Expenses	Electricity purchases and system access fees		143		85
	Other raw materials and operating charges		40		44
	Staff costs and employee benefits		84		77
	Depreciation and amortization		41		39
	Franchise fee and property taxes		61		51
	Other administrative expenses		12		7
			381		303
Operating income before corporate charges			101		85
Corporate charges			32		30
Operating income		**$**	**69**	**$**	**55**

Operating income for the year ended December 31, 2010	**$**	**55**
Increase due to higher approved customer rates		14
Operating income for the year ended December 31, 2011	**$**	**69**

* Distribution and Transmission's operating income for 2010 was restated reflecting the transfer of the management of Technologies from Water Services to Distribution and Transmission.

For the year ended December 31, 2011, Distribution and Transmission's operating income increased $14 million compared with 2010 primarily due to increased revenues from higher approved customer rates and improved timing of approvals to bill and collect electricity transmission flow-through costs from customers than was experienced in the past, partially offset by increased costs charged by the electric system operator in 2011.

Years ended December 31,	2011	2010
Distribution reliability and volumes		
Reliability (system average interruption duration index in hours)	0.83	0.83
Electricity distribution (gigawatt-hours)	7,347	7,246

The strategic focus of Distribution and Transmission is operational excellence; primarily the safe and reliable distribution of electricity to its customers. Distribution and Transmission's primary measure of distribution system reliability is the System Average Interruption Duration Index (SAIDI), which it attempts to minimize. This measure captures the annual average number of hours of interruption experienced by Distribution and Transmission's customers, including scheduled and unscheduled interruptions to its primary distribution circuits. In 2011, the SAIDI was 0.83 hours, which is comparable to 2010 before normalization for major event days and interruptions due to loss of supply or causes resulting from events on systems operated by other wire owners. The normalized SAIDI for 2011 was 0.83 hours compared with 0.57 in 2010. Distribution and Transmission's SAIDI for 2011 was targeted at 0.88. Although Distribution and Transmission surpassed its 2011 target, its reliability performance did not improve over 2010. Despite Distribution and Transmission's continuous system availability improvement efforts in 2011, reliability performance was lower than 2010 primarily due to cable faults and other factors. The key system reliability improvement efforts undertaken were the rejuvenation or replacement of underground distribution cables to mitigate cable failures, the installation of automated switches on selected circuits to isolate faults and restore service to customers faster and the construction of new circuits to strengthen the electrical system. Distribution and Transmission will continue with its reliability improvement programs to further address these issues and help improve overall system reliability in the future. Electricity distribution volumes in 2011 were consistent with 2010.

During 2011, Distribution and Transmission's joint application with AltaLink L.P. for the Heartland Transmission project was approved by the AUC and the project is anticipated to be completed in late 2013. Once complete, the Heartland Transmission project will be added to rate base. The rate base is the value of a utility's property on which it is permitted to earn a fair return, as approved by the regulator within its service area. In addition, the AESO has outlined a significant growth strategy for Alberta's electricity transmission infrastructure and has indicated that some of the proposed electricity transmission projects may be open to a competitive bid process, as opposed to the historic process whereby each transmission facility operator performs approved work within their designated service area. Should the AUC apply a competitive bid process to future electricity transmission projects, Distribution and Transmission would have the opportunity to bid on the projects and increase its rate base if successful in its bids.

The AUC has directed all electricity distribution companies to transition from the traditional cost of service rate model to a performance based regulation model. Given the integrated nature of the distribution and transmission business, Distribution and Transmission is currently in the process of transitioning its distribution and transmission rates to this new model effective 2013. The initiative is intended to allow a utility to recover its costs and earn a fair rate of return over a longer regulatory test period while providing an incentive to manage costs below the inflationary adjustment built into the performance based rates. This transition is subject to regulatory hearings which will take place in 2012.

Energy Services

Energy Services earns income from the supply of electricity to RRT and default rate customers (customers with higher electricity volumes that are not under a competitive contract with an electricity provider) in the EPCOR Distribution and Transmission Inc. and FortisAlberta Inc. service areas and several Rural Electrification Association service territories. Energy Services also provides billing, collection, and contact center services to another EPCOR subsidiary and the City Waste and Drainage Services departments. It provided similar services to Alberta Energy Savings Limited Partnership (AESLP) until November 30, 2011 when the related contract expired without renewal. Energy Services focuses on providing excellent service experiences for its customers and measures call answer performance, billing performance and customer satisfaction and reports results to its regulator on a quarterly basis.

Energy Services operates under provincial cost of service rate regulations intended to allow it to recover its prudent costs and earn a fair rate of return. Its regulator is the AUC.

Energy Services Operating Income

Years ended December 31,			**2011**		**2010**
(including intersegment transactions, $ millions)					
Revenues	Electricity revenues	$	1,133	$	838
	Commercial and other		30		34
			1,163		872
Expenses	Electricity purchases and system access fees		1,077		776
	Other raw materials and operating charges		1		-
	Staff costs and employee benefits		19		21
	Depreciation and amortization		9		12
	Other administrative expenses		26		24
			1,132		833
Operating income before corporate charges			31		39
Corporate charges			15		12
Operating income		**$**	**16**	**$**	**27**

Operating income for the year ended December 31, 2010	**$**	**27**
Increase due to higher approved customer rates and higher volumes		8
Decrease due to lower commercial services margin		(5)
Decrease due to fair value adjustments on financial electricity purchase contracts		(14)
Operating income for the year ended December 31, 2011	**$**	**16**

For the year ended December 31, 2011, Energy Services' operating income decreased by $11 million. This decrease was primarily due to the net impact of the unfavorable fair value adjustments on financial electricity purchase contracts associated with the EPSP and lower commercial services margin as a result of less services provided, partially offset by higher revenues resulting from higher approved customer rates and volumes. There were no corresponding fair value adjustments in 2010.

Energy Services' retail sales volumes were as follows:

Years ended December 31,	**2011**	**2010**
Electricity (gigawatt-hours)		
RRT	5,734	5,600
Default	886	844
	6,620	6,444

A portion of the margin that Energy Services earns on RRT electricity sales is based on an EPSP approved by the AUC. The previous EPSP expired on June 30, 2011. In March 2011, the AUC approved Energy Services' new EPSP which took effect on July 1, 2011. In May 2011, as part of the new EPSP, Energy Services commenced the direct management of its electricity procurement requirements where they were outsourced under the previous EPSP. Under the new EPSP, Energy Services manages its exposure to fluctuating wholesale electricity spot prices by entering into financial electricity purchase contracts up to 45 days in advance of the month of consumption in order to fix the price of electricity to be purchased under a well-defined purchase and risk management process set out in the EPSP. Energy Services expects similar RRT sales volumes in 2012, with the continued possibility of decreases due to customers having the option of signing competitive contracts with electricity retailers.

CONSOLIDATED BALANCE SHEETS

($ millions) **December 31,**	**2011**	**2010**	**Increase (decrease)**	**Explanation**
Cash and cash equivalents	$ 316	$ 104	$ 212	Refer to liquidity and capital resources section.
Trade and other receivables	372	506	(134)	Decrease primarily due to a lower current portion of long-term receivable from Capital Power, partially offset by year-over-year increase in electricity prices.
Inventories	12	10	2	Increase primarily due to purchases made for anticipated needs in the first quarter of 2012.
Derivatives	11	-	11	Increase reflects positive fair value adjustments relating to forward foreign exchange contracts and negative fair value adjustments relating to financial electricity purchase contracts more than offset by payments to counterparties.
Finance lease receivables	127	130	(3)	Reflects scheduled lease payment received.
Other financial assets	402	463	(61)	Primarily reflects the sale of our floating-rate notes and current portion of long-term receivable from Capital Power reclassified to trade and other receivables.
Deferred tax assets	43	42	1	
Investment in Capital Power	987	1,192	(205)	Reflects the sale of a portion of and dilutions of investment in 2011 and limited partnership distributions, partially offset by equity income.
Intangible assets	104	100	4	Reflects the acquisition of Chaparral (goodwill), partially offset by amortization of intangible assets.
Property, plant and equipment	2,658	2,385	273	Reflects capital expenditures and the acquisition of Chaparral, partially offset by depreciation expense.
Trade and other payables	264	259	5	Increase primarily due to Heartland Transmission project cost accruals, partially offset by payment of amounts relating to AESLP.
Other current liabilities	34	33	1	
Loans and borrowings (including current portion)	1,699	1,672	27	Reflects issuance of short and long-term debt as well as assumption of long-term debt from Chaparral, partially offset by scheduled repayment of long-term debt.
Deferred revenues (including current portion)	602	544	58	Primarily reflects contributions received from customers and the assumption of Chaparral deferred revenues.
Deferred tax liabilities	1	1	-	
Provisions (including (current portion)	47	51	(4)	Primarily reflects gain on settlement of asset retirement obligations related to Rossdale power plant.
Other non-current liabilities	34	30	4	Primarily reflects leasehold inducement received in relation to EPCOR Tower lease and the assumption of liabilities from Chaparral, partially offset by Gold Bar asset transfer fee payment to the City in the first quarter of 2011.
Equity attributable to the Owner of the Company	2,351	2,342	9	Reflects comprehensive income, partially offset by dividends paid.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Cash inflows (outflows)

($ millions)	Years ended December 31, 2011	2010	Increase (decrease)	Explanation
Operating	$ 123	$ 190	$ (67)	Reflects changes in non-cash operating working capital.
Investing	205	280	(75)	For 2011, primarily reflects proceeds on sale of a portion of investment in Capital Power, proceeds on sale of floating-rate notes, and payments on long-term receivables from Capital Power, partially offset by capital expenditures. For 2010, primarily reflects payments on long-term receivables from Capital Power and proceeds on sale of a portion of investment in Capital Power, partially offset by capital expenditures.
Financing	(116)	(377)	261	For 2011, reflects proceeds from debt offering, partially offset by repayment of long-term debt and common share dividends. For 2010, reflects repayment of long-term debt and common share dividends.
Opening cash and cash equivalents	104	11	93	
Closing cash and cash equivalents	$ 316	$ 104	$ 212	

Cash inflows (outflows)				
	Years ended December 31,			
	2010	2009	Increase	
($ millions)	CGAAP	CGAAP	(decrease)	Explanation
Operating	$ 165	$ 302	$ (137)	Primarily reflects lower cash flows due to the sale of the power generation business in July 2009.
Investing	305	27	278	For 2010, primarily reflects proceeds from sale of a portion of the Investment in Capital Power and payments on long-term receivables from Capital Power, partially offset by capital expenditures. For 2009, primarily reflects proceeds from sale of the power generation business and power syndicate agreement and payments on long-term receivables from Capital Power, partially offset by capital expenditures.
Financing	(377)	(429)	52	For 2010, primarily reflects repayment of short-term debt, common share dividends and net repayment of long-term debt. For 2009, primarily reflects net issuance of long-term debt, partially offset by common share dividends.
Opening cash and cash equivalents	11	111	(100)	
Closing cash and cash equivalents	$ 104	$ 11	$ 93	

LIQUIDITY AND CAPITAL RESOURCES

Years ended December 31, ($ millions)	**2011** IFRS	**2010** IFRS	**2009** CGAAP
Funds from operations[1]	$ 208	$ 193	$ 356
Long-term borrowings during the year	254	-	238
Cash and cash equivalents, at end of year	316	104	11
Short-term debt, at end of year	-	-	-
Ratios[1]			
Debt to equity[2]	42:58	42:58	44:56
Interest coverage on long-term debt [3]:			
Operating income before foreign exchange gains[4]	1.6 X	1.5 X	2.1 X
Operating income before foreign exchange gains and depreciation and amortization[5]	2.5 X	2.3 X	3.2 X
Funds from operations to interest bearing debt (%)[6]	11.8	11.9	18.6
Credit ratings[7]			
Standard & Poor's			
Long-term debt	BBB+	BBB+	BBB+
Preferred shares of subsidiary companies	-	-	P-2 (Low)
DBRS Limited			
Short-term debt	R-1 (low)	R-1 (low)	R-1 (low)
Long-term debt	A (low)	A (low)	A (low)

(1) Funds from operations and ratios in this table are non-IFRS financial measures that do not have any standardized meaning prescribed by IFRS and are unlikely to be comparable to similar statistics published by other entities. They are presented since they are commonly referred to by debt holders and other interested parties in evaluating the Company's financial position and in assessing its creditworthiness. See the Non-IFRS Financial Measures section of this MD&A for a reconciliation of funds from operations. The ratios are explained in the following notes.

(2) Debt to equity is expressed as a ratio of debt as a percentage of total capital to equity as a percentage of total capital. Debt is the sum of short-term debt and long-term debt (including the current portion). Equity is total equity. Total capital is the sum of debt and equity.

(3) Interest coverage on long-term debt excludes gain on sale of power syndicate agreement and loss on sale of power generation business.

(4) For 2010 and 2011, operating income less foreign exchange gains divided by interest on long-term debt and capital lease obligation. For 2009, revenues, less energy purchases and fuel, operations, maintenance and administration, franchise fee, property taxes and other taxes, depreciation, amortization and asset retirement accretion and foreign exchange losses, divided by interest on long-term debt.

(5) For 2010 and 2011, operating income less foreign exchange gains and depreciation and amortization divided by interest on long-term debt and capital lease obligation. For 2009, revenues less energy purchases and fuel, operations, maintenance and administration, franchise fee, property taxes and other taxes, and foreign exchange losses, divided by interest on long-term debt.

(6) Funds from operations to interest bearing debt (expressed as a percentage) is net cash flow from the operating activities divided by short-term debt plus long-term debt (including the current portion).

(7) Rating agencies have disclosed that all current ratings are stable.

Operating Activities

Cash flow from operating activities, which includes changes in non-cash operating working capital, decreased to $123 million in 2011 from $190 million in 2010. The decrease was primarily due to a decrease in non-cash operating working capital.

Working capital requirements in 2012 are expected to increase as a result of the acquisition of Arizona Water and New Mexico Water which closed on January 31, 2012. The Company will fund its

2012 working capital requirements with cash flow from operating activities, the issuance of commercial paper and with existing credit facilities.

Financing

Generally, our external capital is raised at the corporate level and invested in the operating business units. Our external financing has consisted of commercial paper issuance, borrowings under committed credit facilities, debentures payable to the City, publicly issued medium-term notes, U.S. medium-term private debt notes and preferred shares.

In 2011, the Company secured financing to fund its capital expenditures and working capital requirements at a weighted average interest rate of 1.05% per annum through the issue of commercial paper in the year. Short-term borrowing rates remained relatively constant during 2011. In the fourth quarter of 2011, the Company issued U.S. dollar denominated private-debt notes and sold a portion of its investment in Capital Power to fund capital expenditures and the acquisition of Arizona Water and New Mexico Water in 2012. The U.S. dollar denominated private-debt notes carry a weighted average term-to-maturity of 19 years and a weighted average interest rate of 4.30% per annum.

At December 31, 2011, the Company had undrawn amounts available under four credit facilities including a syndicated bank credit facility with two tranches of $250 million each with one committed until 2014 and the other until 2016. The undrawn amounts available under the four credit facilities are summarized in table below:

($ millions) **December 31,**		**2011**		**2010**
Bank lines of credit – committed	$	500	$	500
Bank lines of credit – uncommitted		140		90
		640		590
Letters of credit outstanding		(272)		(135)
Bank lines of credit available	$	368	$	455

Committed bank lines are used principally for the purpose of providing capital and letters of credit. Letters of credit are issued to meet the credit requirements of energy market participants and conditions of certain service agreements. At December 31, 2011, the Company had undrawn bank credit facilities of $368 million (2010 - $455 million), of which $250 million is committed for at least two years and $48 million is committed for at least four years (2010 - $428 million undrawn and committed for at least two years). The majority of the credit facilities are with Canadian tier 1 banks.

The committed bank lines also indirectly back the Company’s commercial paper program which has an authorized capacity of $500 million and an issuance limit of $225 million under the committed bank lines. The commercial paper issuance limit of $225 million was removed from the committed credit facilities effective January 31, 2012. The Company had no commercial paper outstanding at December 31, 2011 and 2010.

On December 1, 2011, the Company filed a Canadian shelf prospectus to replace its then current shelf prospectus which expired in January 2012. Under the new shelf prospectus, the Company may raise up to $1 billion of debt with maturities of not less than one year. At December 31, 2011, the available amount remaining under this shelf prospectus was $1 billion. The new shelf prospectus expires in January 2014.

The Company plans to continue to use commercial paper, existing credit facilities and publicly or privately issued medium-term notes for its financing requirements. Current and longer-term financing requirements could also be funded by a sale of a portion of the Company's investment in Capital Power, pursuant to applicable agreements with Capital Power and as market conditions permit. Should instability in the credit and economic environments worsen, this may adversely affect the interest rates at which the Company is able to borrow. In January 2012, the Company established a new $400 million committed syndicated bank credit facility in order to provide an additional source of liquidity. The new facility can only be used to provide letters of credit. The Company's existing letters of credit will be reissued under the new facility, thereby increasing the credit availability under the syndicated bank credit facility and increasing the Company's liquidity position.

On February 28, 2012, the Company issued $300 million, 4.55% medium-term notes due February 28, 2042, under its base shelf prospectus. The notes were priced to yield 4.565%, pay interest semi-annually and rank equally, except as to sinking fund and statutory preferred exceptions, with all other unsecured and unsubordinated indebtedness of the Company. The notes were used to pay down commercial paper indebtedness and for general corporate purposes.

If the economy were to deteriorate in the longer term, particularly in Canada and the U.S., the Company's ability to renew credit facilities, arrange long-term financing for its capital expenditure programs and acquisitions, or refinance outstanding indebtedness when it matures could be adversely impacted. If market conditions worsen, the Company may suffer a credit rating downgrade and be unable to renew its credit facilities or access the public debt markets. We continue to believe that these circumstances have a low probability of occurring. However, we continue to monitor our capital programs and operating costs to minimize the risk that the Company becomes short of cash or unable to honor its obligations. If required, the Company would look to reduce capital expenditures and operating costs and/or sell a portion of its investment in Capital Power pursuant to applicable agreements with Capital Power and as market conditions permit.

As of March 16, 2012, there were three common shares of the Company outstanding, all of which are owned by the City. EPCOR's dividend policy for these common shares, as set by the City, has remained unchanged since 2000. Under the policy, the annual dividend is set in the fall for the following year at the greater of the current year's dividend adjusted for the forecast change in the consumer price index and 60% of the following year's forecast earnings available to the common shareholder. This policy is subject to amendment in the event of a significant change in EPCOR's business or financial condition. In accordance with the policy, the annual dividends for 2011 were $138 million (2010 - $136 million).

Credit Ratings

In July 2011, DBRS affirmed its credit rating for EPCOR's long-term unsecured debt at A (low) stable and in December 2011, Standard & Poor's affirmed EPCOR's credit rating for long-term unsecured debt at BBB+ stable. These credit ratings reflect the Company's ability to meet its financial obligations given the stable cash flows generated from the regulated water and distribution and transmission businesses. The Company's sale of the power generation assets in 2009 served to improve certain creditworthiness measures. However, the Company continues to be exposed indirectly to the power generation related risks through its remaining 39% economic interest in Capital Power, as well as the long-term loans receivable from Capital Power. As both the equity interest and long-term loans receivable decrease and are replaced with rate-regulated distribution and transmission and water infrastructure assets, the Company's creditworthiness is expected to improve. A credit rating downgrade for EPCOR could result in higher interest costs on new borrowings and reduce the availability of sources and tenor of investment capital.

Financial Covenants

EPCOR is currently in compliance with all of its financial covenants as set out in the Amended and Restated Credit Agreement dated July 9, 2009, as amended, and the financial covenants of its U.S. private-debt notes. Based on current financial covenant calculations, the Company has sufficient capacity to borrow to fund current and long-term requirements. Although the current risk of breaching these covenants is low, it could potentially result in a revocation of EPCOR's credit facility causing a significant loss of access to liquidity.

2012 Cash Requirements

EPCOR’s projected cash requirements for 2012 includes $800 million to $1 billion for acquisitions and capital expenditures (including $460 million for the Arizona Water and New Mexico Water acquisition, which closed in January 2012, and $150 million for our share of the construction of the Heartland Transmission project), $118 million in interest payments, $25 million for net scheduled debt re-payments and $141 million for common share dividends.

If total cash requirements for 2012 remain as planned, the sources of capital will be cash on hand, operating cash flows, partnership distributions from Capital Power, interest and principal payments related to the long-term loans receivable from Capital Power, the issuance of commercial paper, existing credit facilities and public or private debt offerings. We are actively pursuing growth opportunities which may be funded by any of the sources of capital listed above.

The Company has an adequate contractual liquidity position. The Company continues to be in compliance with the financial covenants of its credit facilities and publicly and privately issued debt, and at December 31, 2011, it had $316 million (2010 - $104 million) in cash and cash equivalents, and credit available under various bank lines described above under Financing.

The Company expects to have sufficient liquidity to finance its plans and fund its obligations in 2012.

Contractual Obligations

($ millions)	Payments due by period					
	2012	2013	2014	2015	2016 and thereafter	Total
Capital projects[1]	$ 2	$ -	$ -	$ -	$ -	$ 2
Water and wastewater infrastructure projects[2]	3	-	-	-	-	3
Arizona Water and New Mexico Water acquisition	460	-	-	-	-	460
Gold Bar transfer fee	12	10	6	1	-	29
Asset retirement obligations	4	-	-	-	-	4
Loans and borrowings, net of sinking fund payments received	25	18	15	15	1,639	1,712
Interest payments on loans and borrowings	118	109	104	103	1,240	1,674
Operating leases	13	13	13	13	194	246
Total contractual obligations	$ 637	$ 150	$ 138	$ 132	$ 3,073	$ 4,130

(1) EPCOR's obligations for capital projects include obligations for Gold Bar upgrades.

(2) EPCOR's obligations for water and wastewater projects include obligations for Chaparral and Suncor Energy.

In the normal course of business, EPCOR provides financial support and performance assurances, including guarantees, letters of credit and surety bonds, to third parties in respect of its subsidiaries. The liabilities associated with these underlying subsidiary obligations are included in the consolidated balance sheet.

In December 2007, the Company entered into a long-term leasing agreement to lease space in a new office tower in downtown Edmonton. The agreement, which took effect in the fourth quarter of 2011 commensurate with the Company's move into the new office space, extends for 20 years and provides the Company with three successive five-year renewal options. Under the terms of the lease, the Company has committed to make annual payments of $10 million for the period of January 1, 2012 through December 31, 2021 and $11 million for the period of January 1, 2022 through December 31, 2031. The Company has negotiated to sublease approximately 34% of the space to Capital Power under the same terms and conditions as its lease with the landlord.

In March 2009, the Gold Bar wastewater assets and associated long-term debt were transferred to EPCOR from the City. EPCOR issued $112 million of long-term debt to the City and incurred a $75 million transfer fee payable to the City for the Gold Bar asset transfer. The remaining long-term debt bears interest at a weighted average interest rate of approximately 5.21% and remaining principal repayments are included in the table of contractual obligations above. The transfer fee is payable in annual installments over the period from 2009 to 2015 and is included in the table of contractual obligations above.

OUTLOOK

On January 31, 2012, the Company completed the acquisition of 100% of the stock of Arizona Water and New Mexico Water from American Water Works Company, Inc. for cash consideration of $460 million (US$461 million) and the assumption of $9 million (US$9 million) in long-term debt, subject to certain adjustments. Arizona Water and New Mexico Water are public utility companies engaged principally in the purchase, production, distribution and sale of water to approximately 123,000 customers and wastewater treatment and related services to approximately 51,000 customers. These customers live in 13 municipalities in the states of Arizona and New Mexico. This investment will provide the Company with a strong hub in the U.S. Southwest, consistent with the Company's strategic plan for expansion. The Company expects to receive decisions on two rate applications, filed by Arizona Water and New Mexico Water prior to their acquisition, in the second quarter of 2012.

In 2011, we focused on prudent and responsible business operations and growth in water and electricity infrastructure. In 2012, we intend to focus on continued growth in water and electricity rate-regulated infrastructure in conjunction with further expansion of commercial water operations.

Demand for water is expected to continue to increase and we anticipate increased requirements for better water management practices including watershed management and conservation. With municipal budgets under pressure, municipal governments are considering the opportunities presented by public-private partnerships. We will pursue expanding our portfolio of commercial water contracts, particularly in the Alberta oil sands.

The existing electricity transmission infrastructure in Alberta is inadequate to meet the growing demand for electricity in the province and we will continue to strongly support government and public approval for the construction of additional transmission capacity in the province.

In February 2010, the AUC announced a rate regulation initiative proposing a performance based regulation (PBR) type framework under which rates for electricity and natural gas distribution services in Alberta would be adjusted annually by a formula recognizing expected inflation and achievable productivity improvements. The stated objectives of PBR include promoting efficiency, allowing the opportunity for affected companies to earn a fair return and recover prudently incurred costs, reducing the regulatory burden, recognizing the uniqueness of affected companies and allowing customers to share in the benefits. A PBR framework differs substantially from the current cost of service model whereby utilities are allowed to recover prudent costs and earn a set rate of return. 2012 is expected to be the last year that EPCOR's distribution and transmission businesses will operate under traditional cost of service regulation. The AUC's initiative is now underway with a hearing scheduled for the second quarter of 2012 and a decision is anticipated in the third quarter of 2012. EPCOR has submitted a PBR framework wherein cost recovery for operations and maintenance costs will be determined in each of the five years (2013 – 2017) according to an escalation formula approved by the AUC. EPCOR has requested that cost of service regulation continue for the recovery of capital related costs owing to difficultly in establishing forecasts or formulae that would adequately address significant growth anticipated in capital costs. EPCOR has asked that the same approach be adopted for its transmission business owing to their highly integrated nature. Distribution and Transmission submitted its 2012 cost of service rate application in November 2011, which will form the basis for 2013 rates under the PBR framework. A decision from the AUC is expected in the second half of 2012.

The Company expects to file its Energy Services cost of service rate application, for 2012 and 2013, in the second quarter of 2012 where it previously expected to file it in the first quarter of 2012.

On February 23, 2012, the Government of Alberta announced a number of initiatives that will affect the Alberta electric industry including EPCOR. The initiatives included:

- Directing the AUC to conduct a public transmission cost recovery inquiry into approaches that could mitigate the rate impact of new transmission on consumers.
- Ensuring that all future major transmission infrastructure projects are awarded using a competitive procurement process.
- Undertaking a review of the variable, regulated retail electricity rate to ensure it meets the needs of Alberta consumers in the context of an open and competitive retail sector.
- A request that the AUC freeze ancillary costs included on Albertans' power bills including distribution, transmission, rider and administration charges until the completion of the review. On March 13, 2012, the AUC announced that it will continue to process and complete the record for relevant applications currently in progress or pending however, the AUC will not issue decisions that will result in rate increases.

We believe the freeze on collection of ancillary costs will negatively impact EPCOR's financial results since we may be unable to collect from customers, amounts that would otherwise be billed to them and recognized in revenues. The revenues primarily relate to costs subject to deferred collection treatment by the regulator and were expected to be collected during the first half of 2012. We anticipate the potential shortfall to be between $5 million and $10 million. In addition, this may also mean that any further deferral amounts that arise in 2012, while the freeze is in effect, will not be eligible for collection from customers until after the freeze is lifted, which is not expected to be until July 2012. As a result, we expect our earnings from core operations to be lower in 2012 due to this and other key factors as follows:

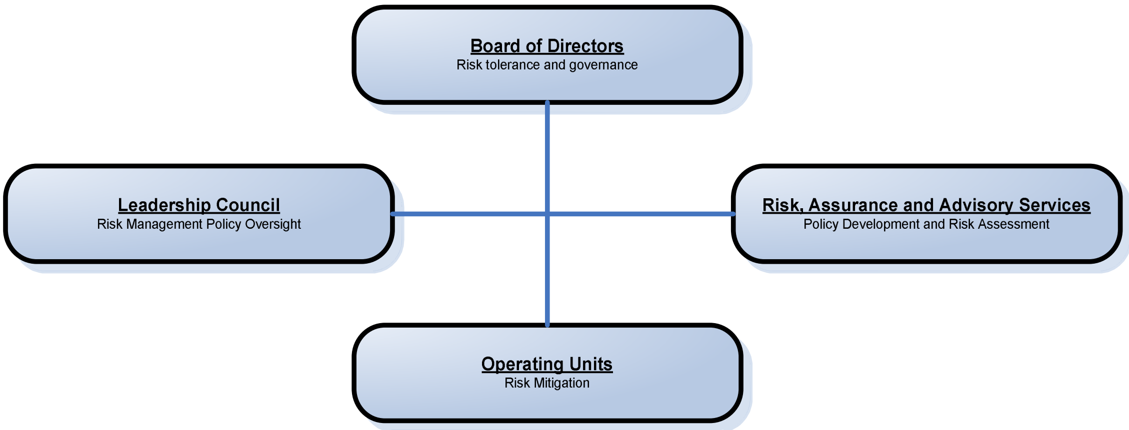
- Higher financing costs due to higher average debt levels in 2012;
- Decreased equity income from Capital Power as a result of a lower economic interest in Capital Power;

  partially offset by

- Higher approved utility rates, offset by the impact of ancillary rate freezes announced by the Alberta government;
- Additional U.S. water operations; and
- Income from increased activity related to the Company's expanding commercial water services operations.

RISK FACTORS AND RISK MANAGEMENT

Approach to risk management



Our approach to enterprise risk management (ERM) is to identify, monitor and manage the key controllable risks facing the Company and consider appropriate actions to respond to uncontrollable risks. ERM includes the controls and procedures implemented to reduce controllable risks to acceptable levels and the identification of the appropriate management actions in the case of events occurring outside of management's control. Acceptable levels of risk and risk appetite for EPCOR are established by the Board of Directors, representing the shareholder, and are embodied in the decisions and corporate policies associated with risk. ERM is generally carried out at three levels. Firstly, general ERM oversight framework reviews and recommendations, and reviews of risk compliance are provided by Leadership Council, EPCOR's senior executive group, based upon objectives, targets and policies approved by the Board of Directors. Secondly, the Director, Risk, Assurance and Advisory Services is responsible for developing the framework and assessing risk at an enterprise level and monitoring compliance with risk management policies. The Director, Risk, Assurance and Advisory Services provides the Board of Directors with an enterprise risk assessment quarterly. Thirdly, the business units and shared service units are responsible for carrying out the risk management and mitigation activities associated with the risks in their respective operations. These risk management activities are integral aspects of the business units' and shared service units' operations. EPCOR believes that risk management is a key component of the Company's culture and we have put into place cost-effective risk management practices. At the same time, EPCOR views risk management as an ongoing process and we continually review our risks and look for ways to enhance our risk management processes.

The Company's Ethics Policy includes procedures which provide for confidential disclosure of any wrong-doing relating to accounting, reporting and auditing matters. The policy prohibits any retaliation against any person making a complaint. During 2011, no complaints were received under the Ethics Policy.

Risks Related to Investment in Capital Power

Significant reliance is placed on the capacity of Capital Power to honor its back-to-back debt obligations with EPCOR. While EPCOR has a significant economic interest in Capital Power, EPCOR does not control Capital Power. Should Capital Power fail to satisfy these obligations, EPCOR's capacity to satisfy its debt obligations would be reduced and EPCOR would need to satisfy its own debt obligations by other means.

In addition, EPCOR relies on the cash flow from Capital Power partnership distributions as one of the Company's funding sources. The Capital Power distributions are paid at the discretion of the general partner of Capital Power L.P., which EPCOR does not control. There can be no assurance that Capital Power L.P. will continue to pay distributions at current levels as the distributions may be reduced or eliminated entirely in the future. Reduced future distributions as a result of our expressed intent to sell down our interest in Capital Power over time are expected and have been factored into our plans.

Underlying these risks are the specific business risks of Capital Power. EPCOR has no ability to manage these risks directly. EPCOR, by virtue of its holdings of exchangeable limited partnership units in Capital Power L.P., has four elected directors on the Board of Capital Power. This does give EPCOR some input into certain of the operating and strategic decisions made by Capital Power, including risk management. EPCOR can indirectly reduce its exposure to these risks by reducing its interest in Capital Power.

Capital Power has indemnified EPCOR for any losses arising from its inability to discharge its liabilities, including any amounts owing to EPCOR in relation to the long-term loans receivable.

Operational Risks

The ability of the water treatment plants to maintain adequate treatment and testing of water on a continuous basis is essential in seeking to ensure that the prescribed requirements under regulation or conventional industry standards are met. Failure to properly maintain fully functioning treatment and measurement systems and provide a reliable source of water could result in regulatory fines, lost revenue or potential lawsuits.

Although distribution and transmission facilities have operated through their construction and periodic upgrades and have generally continued operations in accordance with expectations, there can be no assurance that they will continue to do so. To the extent that these networks experience outages due to equipment failure or suffer disruption for other reasons, delivery of power or water and associated revenues may be negatively affected.

Operational risk in Distribution and Transmission, and Water Services is managed through sound maintenance and safety practices. Water Services performs continuous and rigorous quality control testing of water purification consistent with government and industry standards. The ability of the water treatment plants to maintain adequate treatment requirements is dependent on continuous water testing in order that the prescribed requirements under regulation or conventional industry standards are met. Failure to properly maintain fully functioning treatment and measurement systems could result in regulatory fines, lost revenue or the occurrence of public health issues. Our maintenance practices are augmented by an inventory of strategic spare parts, which can reduce down-time considerably in the event of power or water system interruptions.

We use several key computer application systems to support our various operations such as electricity and water distribution network control systems, electricity and water plant control systems and electricity settlement and billing systems. We take measures to reduce the risk of malicious corruption or failure of these systems and the hardware and network infrastructure on which they operate, as well as theft of electronic data.

Political, Legislative and Regulatory Risk

EPCOR is subject to risks associated with changing political conditions and changes in federal, provincial, state, local or common law, regulations and permitting requirements in Canada and the U.S. It is not possible to predict changes in laws or regulations that could impact the Company's operations, income tax status or ability to renew permits as required.

EPCOR is subject to risks associated with the rate regulation processes that much of its operations are subject to. Such processes can result in significant lags between the time changes to customer rates or tariffs are applied for and the time that regulatory decisions are received. Furthermore, the regulator may deny or alter the applied for customer rates or tariffs.

Under the Settlement System Code of the *Electric Utilities Act* (Alberta), a retailer must rely on load settlement agents to provide customer consumption data to be used in computing its customers' bills. Under the *Alberta Regulated Rate Option Regulation*, regulated rate providers may not collect from customers an amount undercharged due to a billing error if the consumption occurred more than 12 months before the date of the revised billing.

The AUC sets rates intended to permit the regulated Distribution and Transmission and RRT customer services businesses to recover estimated costs of providing service plus a fair return. Our ability to recover the actual costs of providing service and to earn a fair return is dependent upon achieving the forecasts established in the rate-setting process. The AUC has announced that effective January 1, 2013, it will be moving to a PBR structure for electricity distribution and transmission and natural gas distribution utilities in Alberta. EPCOR filed its PBR plan pertaining to its electricity distribution and transmission utilities with the AUC in the third quarter of 2011. The process has risks customarily associated with rate-regulated tariff filings. Commencing July 2010, electricity rates in Alberta for regulated rate option (RRO) eligible customers became based entirely on the index price of the next month's cost of electricity. As this electricity pricing model results in increasing volatility in prices to our customers, it may impact our volume of electricity sales, as well as electricity margins.

EPCOR's water treatment and distribution services to customers within Edmonton are rate-regulated by Edmonton City Council pursuant to a Performance Based Regulation Plan bylaw. Edmonton City Council approved a renewal of the Performance Based Regulation Plan bylaw in October 2011 for the five-year period commencing April 1, 2012. The renewal also incorporated the costs associated with the provision of wastewater treatment services supplied from the Gold Bar Wastewater Treatment Plant to the residents of Edmonton. Rates approved under this bylaw are intended to allow the Company to recover its operating costs and earn a return on equity, as well as provide an incentive to manage cost increases below inflation. If the performance targets outlined in the bylaw are achieved, water and wastewater rates are increased by the change in the rate of inflation less an efficiency factor. Our ability to fully recover operating and capital costs and to earn a fair return is dependent upon achieving the performance targets prescribed in the bylaw, maintaining cost increases below inflation and managing operational risks.

Rates for water sales to regional water commissions that supply water to communities surrounding Edmonton are regulated by the AUC on a complaints-only basis, whereby such communities may apply to the AUC to resolve disputes related to rates, tolls or charges determined by the Company. EPCOR sets the rates it charges to these regional water commissions to recover related operating and capital costs plus a reasonable rate of return. Actual operating and capital costs associated with the provision of water to the commissions, and a fair return on rate-base, are recovered in accordance with a full cost-of-service method which has been approved by the AUC.

In December 2008, the Regional Water Customers Group (RWCG), which represents the interests of these regional water customers, requested that the AUC issue a Notice of Application in respect of its complaints regarding wholesale water rates for the years 2004 to 2007. The AUC decision was received in June 2011. In September 2011, Water Services refiled its 2004-2007 cost of service models to reflect its interpretation of the AUC's decision. A conclusion on the refiling will likely not occur until the first quarter of 2012. Rates associated with wastewater treatment services provided to the residents of Edmonton at Gold Bar are regulated by Edmonton City Council. The master agreement related to the transfer of Gold Bar from the City to EPCOR in March 2009 contains provisions to address the allocation of Edmonton City Council-approved sanitary utility fees charged to Edmonton residents and businesses, to EPCOR and the City's Drainage Services department. EPCOR's allocation of the fees is for wastewater treatment, and the City's Drainage Services department's allocation of the fees is for collection and transmission of wastewater to Gold Bar. EPCOR's net income is affected by the revenue allocation between EPCOR and the City's Drainage Services department, which is based on a relative cost of service between the collection and transmission and wastewater treatment functions, and our ability to obtain approval for sanitary utility rate increases from the regulator, Edmonton City Council, for the recovery of our costs and a fair return on equity.

Water and wastewater services in the U.S. are provided by EPCOR's U.S. subsidiaries and are subject to regulation by the state regulatory commissions within Arizona and New Mexico. Rates and services in Arizona are regulated by the Arizona Corporation Commission and the rates are determined using cost-of-service principles applied to a historical test year. Rates and service in New Mexico are regulated by the New Mexico Public Regulation Commission. The rates are also determined using cost-of-service principles applied to a historical test year. Rates approved by the regulatory commissions are intended to allow for a recovery of operating and capital costs and provide for a fair return on equity.

Strategy Execution Risk

Our growth strategy is dependent on the development, acquisition and / or operation of water and wastewater infrastructure for municipal and commercial / industrial customers (primarily related to oil sands). Both of these markets are defined as emerging and currently do not have clearly established protocols for third party participants such as EPCOR and are subject to a variety of external forces. For example, the oil sands market could be potentially delayed by postponement of capital projects and depressed oil prices. Should either of these markets not develop as quickly or as fully as envisioned, the Company's growth plans could be similarly delayed.

EPCOR's growth strategy is also dependent on the development and / or acquisition of new electricity distribution and transmission assets. Such growth is dependent on the availability of such assets in the marketplace which will be impacted by the willingness of parties to sell such assets, political and public sentiment regarding third party ownership and EPCOR's cost competitiveness. These risks could result in delays or curtailment of EPCOR's growth plans.

Business development projects, including acquisitions, can take a relatively long period of time to execute, exposing such projects to event and external factor risks that may emerge and thereby alter project economics or completion.

For each new business development project, EPCOR seeks to ensure project success by addressing project risks, including events and external factors, as part of its due diligence process.

Weather Risk

Weather can have a significant impact on our operations. Melting snow, freeze / thaw cycles and seasonal precipitation in the North Saskatchewan River watershed affect the quality of water entering our Edmonton water treatment plants and the resulting cost of purification. Weather variability and seasonality also impact the demand and supply of water and electricity in our respective businesses in both Canada and the U.S. Extreme weather can impact the physical operation of our facilities.

Extreme weather can cause damage to distribution and transmission equipment and wires, temporarily disrupting the reliable supply of power to customers and can cause unpredictability in the demand for power. Unseasonal temperature changes can cause water main breaks temporarily disrupting the reliable supply of water to customers.

Weather that varies significantly from historical norms can result in changes in quantity and shape of the provincial power load. EPCOR procures power to service its RRO customers in advance of the consumption month and the quantity procured is based on historical weather and usage patterns. Unseasonal temperatures can cause a mismatch between the power procured in advance of the consumption month and actual customer usage, with a corresponding variance in income from the RRO business from expectations.

Financial exposures associated with extreme weather are partly mitigated through our insurance programs.

Financial Liquidity Risk

EPCOR's internally generated funds from operations generally do not provide sufficient capital to undertake or complete ongoing or future development, enhancement opportunities or acquisition plans and accordingly, the Company requires additional financing from time to time. The ability of the Company to arrange such financing will depend in part upon prevailing market conditions at the time, the Company's business performance as well as the ability to sell additional interests in Capital Power. If the Company's revenues or cash flows decline, it may not have the capital necessary to undertake or complete the initiatives. There can be no assurance that debt or equity financing will be available or that cash generated by operations will be sufficient to meet these requirements or for other corporate purposes. Furthermore, if financing is available, there can be no assurance that it will be on terms acceptable to the Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business, prospects and financial condition. Further discussion is included in Liquidity and Capital Resources in this MD&A.

EPCOR's financial risks are governed by a Board-approved financial exposure management policy, which is administered by EPCOR's Treasurer.

Project Risk

Our construction and development of electricity transmission and distribution and water treatment facilities and acquisition activities are subject to various engineering, construction, stakeholder, government and environmental risks. These risks can translate into performance issues, delays and cost overruns. Project delays may delay expected revenues and project cost overruns could make projects uneconomic. Our ability to complete projects successfully depends upon numerous factors beyond our control such as unexpected cost increases, ability of third parties to access financing and

/ or credit facilities, accidents, availability of skilled labor, strikes and regulatory matters. Many of the water and wastewater growth projects currently pursued by the Company require design and construction capabilities that are not part of the services presently offered by EPCOR. In order to pursue these projects, strategic partnerships have been established with reputable firms that have an established track record of infrastructure design and construction. Should these partnerships dissolve or are not recognized by the market as a viable approach, the Company's growth plans will potentially be curtailed.

We attempt to mitigate project risks by performing detailed project analysis and due diligence prior to and during construction or acquisition, and by entering into favorable contracts for various services to be provided as required.

Availability of People

Our ability to continuously operate and grow the business is dependent upon retaining and developing sufficient labor and management resources. As with most organizations, the Company is facing the demographic shift where a large number of employees are expected to commence retirement over the next few years. Failure to secure sufficient qualified technical and leadership talent may impact EPCOR's operations or materially increase expenses.

We believe that we employ good human resource practices and have been named a top 50 employer in Alberta by MediaCorp Canada Inc. We continue to monitor developments and review our human resource strategies so that we have an adequate supply of labor and management.

Electricity Price and Volume Risk

EPCOR sells electricity to RRO customers under a RRT. The amount of electricity to be procured, the procurement method and electricity selling prices to be charged to these customers is determined by the EPSP under which the Company directly manages procurement of the electricity for the RRO customers. All electricity for the RRO customers is purchased in real time from the AESO in the spot market. Under the EPSP, the Company uses financial contracts to hedge the RRO requirements and incorporate the price into customer rates for the applicable month. Fixed volumes of electricity are purchased at fixed prices using financial contracts-for-differences up to 45 days in advance of the month in which the electricity (load) is consumed by the RRO customers. The volume of electricity purchased in advance is based on load (usage) forecasts for the consumption month. When consumption varies from historical consumption patterns, EPCOR is exposed to prevailing market prices because it must either buy electricity if its volumes procured are short of actual load requirements or sell the electricity if its volumes procured are greater than the actual load requirements. Exposure to variances in electricity volume can be exacerbated by other events such as unexpected generation plant outages and unusual weather patterns.

Under contracts-for-differences the Company agrees to exchange, with a single creditworthy and adequately secured counterparty, the difference between the AESO electricity spot market price and the fixed contract price for a specified volume of electricity up to 45 days in advance of the consumption date, all in accordance with the EPSP. The contracts-for-differences are referenced to the AESO electricity spot price and any movement in the AESO price results in changes in the contract settlement amount. If the risks of the EPSP were to become untenable, EPCOR could test the market and potentially re-contract the procurement risk under an outsourcing arrangement at a certain cost that would likely increase procurement costs and reduce margins.

Environment Risk

There are a variety of environmental risks associated with EPCOR's water and wastewater operations and its electricity distribution and transmission businesses. EPCOR's power and water operations are subject to laws, regulations, and operating approvals which are designed to reduce the impacts on the environment. Environmental risks associated with water and wastewater operations include water supply, wastewater discharge, biogas release, and residuals management. Risks associated with electricity distribution and transmission operations include the unintended environmental release of substances such as oil from its oil-filled pipe-type cable, hydraulic oil and polychlorinated biphenyl transformer fluid. A material environmental event could materially and adversely impact EPCOR's business, prospects, reputation, financial conditions, operations or cash flow. Furthermore such incidents could result in spills or emissions in excess of those permitted by law, regulations or operating approvals.

Compliance with future environmental legislation may require material capital and operating expenditures and failure to comply could result in fines and penalties or the regulator could force the curtailment of operations. There are uncertainties associated with current legislative proposals including implementation details, their impact on current licenses and permits, and how compliance costs might be recovered through prices or shared among customers and stakeholders. Further, there can be no assurances that compliance with and/or changes to environmental legislation will not materially and adversely impact EPCOR's business, prospects, financial conditions, operations or cash flow.

EPCOR's water operations are regulated with stringent water and wastewater treatment standards and controls covering quality of treated water and wastewater effluent, the number, frequency and form of water quality testing, as well as mandatory improvements to the water and wastewater treatment processes. Water and wastewater technologies and supporting processes are continuing to evolve and be influenced by more stringent regulation and environmental challenges. Failure to identify and deploy viable new technologies to meet these regulations and challenges could undermine the competitiveness of EPCOR's market position and exclude it from some market opportunities.

We seek to ensure that we comply, in all material respects, with the laws, regulations and operating approvals affecting our facilities, and minimize the potential for incidents by incorporating environmental management practices in our strategy, policies, processes and procedures. To achieve this, we require each facility to have an environmental management system (EMS) which is based on the ISO 14001 standard. These systems encompass the identification of the scope, objectives, training and stewardship of our environmental responsibility. Each plant and facility is also subject to environmental audits to help ensure compliance with the EMS and all regulations. The Edmonton waterworks system (including the Rossdale and E.L. Smith water treatment plants) achieved EnviroVista Champion status as of June 2011. Additionally, EPCOR Water Services is working towards formal implementation of an ISO 14001 Environmental Management System designation for the Gold Bar facility.

Chaparral obtains water to treat and sell to customers primarily from the Central Arizona Project canal. The Central Arizona Project conducts water quality testing upstream of the take-off point and has a formal notification process in place to notify Chaparral of any water quality issues that may arise. Chaparral also has developed an Emergency Operations Plan which addresses environmental water quality issues and provides further risk mitigation.

Our strategy includes a commitment to environmental performance on existing and new facilities and EPCOR's environmental policy commits the Company and all of its employees to environmental compliance and stewardship. Our water and wastewater operations are controlled through stringent water treatment standards and controls covering the quality of treated water and the number, frequency and form of water quality testing, as well as mandatory improvements to the water treatment process. Water and wastewater technologies and supporting processes are continuing to evolve and be influenced by more stringent regulation and environmental challenges. The Company is actively involved in a watershed management program, which involves the protection and management of our Edmonton water source from impurities such as soil particles, excess nutrients, fertilizers, microbiological contaminants and organic materials. Activities undertaken include river water quality monitoring, forming stakeholder partnerships to work on watershed issues, and acting as a resource and leader on quality issues of the North Saskatchewan River Basin.

Credit Risk

Credit risk is the possible financial loss associated with the ability of counterparties to satisfy their contractual obligations to EPCOR, including payment and performance.

We manage credit risk and limit exposures through our credit policies and procedures. These include an established credit review, rating and monitoring process, specific terms and limits, appropriate allowance provisioning and use of credit mitigation strategies, including collateral arrangements.

RRO and Default Supply Credit Risk

Exposure to credit risk for residential and commercial customers under default electricity supply rates are generally limited to amounts due from the customers for electricity consumed but not yet paid for. As the electricity procurement for these customers has evolved to shorter terms, our potential exposure to losses for the purchase of electricity that is not consumed has been largely mitigated.

This portfolio is reasonably well diversified with no significant credit concentrations. Historically, credit losses in these customer segments have not been significant and depend in large measure on the strength of the economy and the ability of the customers to effectively manage their financial affairs through economic cycles and competitive pressures. While electricity is considered an essential service and there has been some improvement in the economies in which the Company operates over the past two years, EPCOR may experience credit losses in the future should economic conditions deteriorate.

EPCOR's exposure to RRO and default customer credit risk, which is primarily the risk of non-payment for electricity consumed by these end-use customers, is summarized below. Exposures represent a 60-day potential accounts receivable value for this portfolio.

December 31, ($ millions)	**2011**	**2010**
RRT and default supply customers[(1)(2)]	$ 219	$ 147

(1) Under the *Alberta Electric and Utilities Act*, EPCOR provides electricity supply in its service area to RRO-eligible customers and those commercial and industrial customers in its service areas who have not chosen a competitive offer and consume electricity under default supply arrangements.

(2) EPCOR monitors credit risk for this portfolio at the gross exposure level rather than by individual customer account. RRT regulations allow for the recovery of forecasted credit losses relating to RRT and for the recovery of a percentage of unforecasted credit losses through a deferral account.

The year-over-year increase in exposure relates to the 30-day potential accounts receivable and was driven mainly by higher approved customer rates and higher volumes.

Water Credit Risk

Exposures to credit risk in our regulated and non-regulated water businesses are generally limited to amounts due from the customers for water and wastewater consumed but not yet paid for, as well as amounts for water management services provided under contracts to municipal and industrial customers.

This portfolio is reasonably well diversified with no significant credit concentrations. We have only just commenced operations in Arizona in mid-2011 but operations will expand significantly in 2012 with the acquisition of Arizona Water and New Mexico Water. While water is considered an essential service and there has been some improvement in the economies in which the Company operates over the past two years, EPCOR may experience credit losses in the future should economic conditions deteriorate. EPCOR's exposure to regulated and non-regulated customer credit risk, which is primarily the risk of non-payment for water consumed by these end-use customers, is summarized below. Exposures represent a 60-day potential accounts receivable value for this portfolio.

December 31, ($ millions)	**2011**	**2010**
		Restated(1)
Unrated customers	$ 40	$ 43
Rated customers(2)	$ 15	$ 14

(1) 2010 comparatives have been restated reflecting the transfer of the management Technologies from Water Services to Distribution and Transmission.

(2) Rated customers have investment grade credit ratings which are based on the Company's internal criteria and analyses, which take into account, among other factors, the investment grade ratings of external credit rating agencies when available.

Health and Safety Risk

Our operations have hazardous elements, like high voltage electricity and hazardous chemicals that could have adverse health and safety consequences to our employees, on-site suppliers and customers. Our operations are subject to the risks of a widespread influenza outbreak or other pandemic illness. We have developed plans in Canada to respond to a potential pandemic influenza to help maintain a sufficient healthy workforce and enable the Company to deliver reliable power and water to customers in such an event. We plan to look at similar protocols for our U.S. operations in the future.

We manage health and safety risks through a company-wide health and safety management program and measure health and safety performance against recognized industry and internal performance measures. We conduct numerous external and internal compliance audits to verify that our health and safety management system meets or exceeds the regulatory requirements in which we operate our business. We are committed to working with industry partners to share and improve health and safety within the industry.

Conflicts of Interest

Certain conflicts of interest could arise as a result of EPCOR's relationship with the City, EPCOR's sole common shareholder and regulator for water and wastewater utility rates in Edmonton. The City has the authority to revise the dividend policy in respect of the common shares of the Corporation held by it.

Certain directors and a senior officer of EPCOR are directors of Capital Power. The board of directors of Capital Power currently has 12 members, four of whom are EPCOR nominated directors. The chairman of the board of directors of Capital Power is the chief executive officer of EPCOR.

Foreign Exchange Risk

The Company is exposed to foreign exchange risk on foreign currency denominated forecasted transactions, firm commitments, monetary assets and liabilities denominated in a foreign currency and on its net investments in foreign entities. The Company's direct exposure to foreign exchange risk arises on capital expenditure commitments denominated in U.S. dollars or other foreign currencies and U.S. operations.

The Company's financial exposure management policy attempts to minimize economic and material transactional exposures arising from movements in the Canadian dollar relative to the U.S. dollar or other foreign currencies. The Company coordinates and manages foreign exchange risk centrally, by identifying opportunities for naturally occurring opposite movements and then dealing with any material residual foreign exchange risks.

The Company may use foreign currency forward contracts to fix the functional currency of its non-functional currency cash flows thereby reducing its anticipated U.S. dollar denominated transactional exposure. The Company looks to limit foreign currency exposures as a percentage of estimated future cash flows.

General Economic Conditions, Business Environment and Other Risks

Fluctuations in interest rates, product supply and demand, market competition, risks associated with technology, general economic and business conditions, EPCOR's ability to make capital investments and the amounts of capital investments, risks associated with existing and potential future lawsuits and other regulations, assessments and audits (including income tax) against EPCOR and its subsidiaries, political and economic conditions in the geographic regions in which EPCOR and its subsidiaries operate, difficulty in obtaining necessary regulatory approvals, a significant decline in EPCOR's reputation and such other risks and uncertainties described from time to time in EPCOR's reports and filings with the Canadian Securities authorities could materially adversely impact EPCOR's business, prospects, financial condition, results of operations or cash flows. Transmission risk relates to blackouts or constraints on the system which result from curtailment of output at generation facilities or restrictions on the development of interconnections with new generation facilities. The following table outlines our estimated sensitivity to specific risk factors as at December 31, 2011. Each sensitivity factor provides a range of outcomes assuming all other factors are held constant and current risk management strategies are in place. Under normal circumstances, such sensitivity factors will not be held constant but rather, will change at the same time as other factors are changing. In addition, these sensitivities are presented at December 31, 2011 and the degree of sensitivity to each factor will change as the Company's mix of assets and operations subject to these factors changes.

Factor ($ millions)	**Change**	**Annual Cash Flow**	**Annual Net Income**
Change in RRO customers	+/-5.0%	+/-3	+/-3
Increase in water consumption – Alberta	+3.0%	+5	+5
Decrease in water consumption – Alberta	-2.0%	-3	-3

Litigation Update

In September 2010, the Royal Glenora Club of Edmonton (RGC) commenced a claim against EPCOR and a number of defendants seeking $5 million plus interest and legal costs. This claim arises out of damages suffered by the RGC when a water main was ruptured in July 2009 during the renovation of the RGC's facilities. EPCOR had been previously retained by RGC to relocate a water main to accommodate the renovation. The water main was subsequently ruptured by a sub-contractor retained by a general contractor. The RGC alleges that EPCOR was negligent when the water line was relocated as EPCOR was alleged to have known where the sub-contractor intended to drill piles for the renovation. EPCOR filed a Statement of Defence denying liability in this claim in October 2010. Examinations for discovery were held in this matter in 2011 and are expected to continue in 2012.

In May 2011, all four charges brought against the Company under the Alberta Occupational Health and Safety Act and Occupational Safety Code with respect to the 2007 fatality of a power lineman employee were stayed, ending all legal proceedings on this matter.

Following the AUC's approval of the Heartland Transmission project facility application on November 1, 2011, appeals were filed both with the AUC and the Alberta Court of Appeal. The AUC appeal was filed by the County of Strathcona and the citizens' group "Responsible Electricity Transmission for Albertans". In late December 2011, the AUC rejected Strathcona County's request to suspend the project pending the outcome of the review and variance process. The AUC is expected to render a decision in March 2012 on whether there are sufficient grounds to review and vary its approval of the project. On March 6, 2012, the Alberta Court of Appeal heard arguments on whether to grant leave to appeal to the appellant.

CONTROLS AND PROCEDURES

For purposes of certain Canadian securities regulations, EPCOR is a "Venture Issuer". As such, it is exempt from certain of the requirements of National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings. Accordingly, the Chief Executive Officer and Chief Financial Officer have reviewed the annual information form, annual financial statements and annual MD&A, for the year ended December 31, 2011. Based on their knowledge and exercise of reasonable diligence, they have concluded that these materials fairly present in all material respects the financial condition, results of operations and cash flows of the Company for the periods presented.

ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS

Effective January 1, 2011, IFRS was incorporated into the CICA Handbook for publicly accountable entities. Companies with rate-regulated operations may defer the adoption of IFRS until January 1, 2012, however EPCOR chose to adopt IFRS effective January 1, 2011.

Financial Reporting Processes and Internal Controls

As part of the IFRS conversion project, financial reporting processes as well as internal controls over financial reporting and disclosure controls and procedures, were reviewed. Other than the changes to the accounting and financial reporting systems noted below, no other significant changes to existing processes or controls were identified.

Using the updated accounting and financial reporting systems, the Company was able to report 2010 results under CGAAP for 2010 reporting and prepare 2010 results under IFRS for 2011 comparative reporting.

Significant Accounting Policy Changes

The following areas were identified as having the most impact on the Company's accounting policies:

PP&E

IFRS are different from CGAAP in that certain costs such as overheads and borrowing costs in excess of the entity's actual cost of debt may not be capitalized. Under CGAAP, the Company capitalized an allowance for funds used during construction (AFUDC) which included cost of debt and deemed cost of equity. In addition, IFRS do not have a rate-regulated provision allowing costs not specifically allowed under the standards, but allowed by the rate regulator, such as training costs, to be capitalized.

IFRS are also more specific with respect to the level at which component accounting is required, requiring each significant component of an asset for which different depreciation methods or rates are appropriate, to be accounted for separately.

Under CGAAP, the method used to retire assets of rate-regulated operations resulted in a deferral of any losses. IFRS do not allow this treatment.

Transfers of Assets from Customers

IFRS requires that assets received from customers that are used to connect a customer to the network or to provide ongoing access to a supply of goods or services should be treated as a revenue generating transaction, with the timing of revenue recognition dependent on the service or services provided. Under CGAAP, contributions from customers were recorded as an offset against the cost of the associated asset, and amortized over the life of the asset.

Rate-regulated Accounting

Under IFRS, there are currently no provisions for rate-regulated accounting. However, the International Accounting Standards Board (IASB) has provided transitional relief to first-time adopters via an exemption which allows rate-regulated entities to use the CGAAP carrying amount for property, plant and equipment on the transition date as the deemed cost under IFRS. The Company did not take this election and as a result, recorded the adjustments described above upon conversion to IFRS.

In addition to the changes noted above under PP&E, the absence of any provisions for rate-regulated accounting under IFRS prohibits the recognition of certain regulatory assets and liabilities such as deferral accounts established by the regulator. Not recognizing these assets and liabilities will likely result in greater volatility in the Company's reported net income.

Investments in Associates

Since we use the equity method to account for the investment in Capital Power, we must recognize our equity share of any IFRS related adjustments recorded by Capital Power. The associated IFRS adjustment is comprised of the following components: the accumulated other comprehensive income adjustment relating to the cumulative translation adjustment election (see IFRS 1 below) and the Company's equity share of Capital Power L.P.'s IFRS adjustments relating to the period between the date that EPCOR sold its power generation business to Capital Power (July 2009) and the IFRS transition date.

IFRS 1 – First-time Adoption of International Financial Reporting Standards (IFRS 1)

IFRS 1 provided first-time adopters with a number of elections, of which the following were relevant to EPCOR:

- Fair value or revaluation as deemed cost – Election to use fair value at the date of transition as deemed cost. This election was available on an asset by asset basis. The Company did not elect to apply fair values on conversion.
- Employee benefits – Election to recognize all cumulative actuarial gains and losses associated with employee benefit plans at the date of transition to IFRS. The Company elected to recognize all actuarial losses associated with employee benefit plans at the date of transition.
- Decommissioning liabilities – Election to use a simplified calculation to calculate and restate decommissioning liabilities and related PP&E and depreciation expense. The Company elected to use the simplified calculation, which resulted in no obligation being recorded.
- Transfer of assets from customers – Election to reclassify customer contributions received prior to the transition date. The Company elected to reclassify customer contributions.
- Cumulative translation account – Election to set all foreign currency translation differences in respect of foreign operations that arose prior to the date of transition to be nil at the date of transition. The Company elected to re-set the cumulative translation account to nil.
- Business combinations – Election to apply any date prior to the transition date as the date from which IFRS 3 – Business Combinations (IFRS 3), would be applied. Any business combinations occurring prior to this date would not require retrospective application.

  The Company elected to apply IFRS 3 for any transactions occurring subsequent to December 31, 2009. The transactions occurring prior to that date relate to the acquisition of certain water assets. These business combinations were not restated, and any goodwill arising from such business combinations before the date of transition was not adjusted from the carrying amounts previously determined under CGAAP as a result of election.

  Certain provisions under IFRS 3 were also applicable to the measurement of the Company's investment in Capital Power. As the transaction occurred prior to the elected date of December 31, 2009, these provisions, and related provisions within IAS 27 - Consolidated and Separate Financial Statements, were not applied to the investment.

Impact on Adoption of IFRS on Financial Reporting

The conversion to IFRS resulted in differences in recognition, measurement, and disclosure of balances and transactions in the financial statements. The following tables explain how the transition from CGAAP to IFRS affected the Company's financial position and performance as well as its segments' financial performance for the year ended December 31, 2010.

Reconciliation of equity reported under CGAAP to equity under IFRS at January 1, 2010:

($ millions)	CGAAP	Measurement adjustments	Presentation adjustments	IFRS
Current assets:				
Cash and cash equivalents	$ 11	$ -	$ -	$ 11
Trade and other receivables[1] (a)	502	(21)	-	481
Inventories	11	-	-	11
Deferred tax assets (b)	1	-	(1)	-
	525	(21)	(1)	503
Non-current assets:				
Other assets (a, c, d)	164	(1)	(163)	-
Finance lease receivables (c)	-	-	124	124
Other financial assets (c)	643	-	37	680
Deferred tax assets (b)	40	-	1	41
Investment in Capital Power (e)	1,481	(20)	-	1,461
Intangible assets (d, f)	110	(2)	2	110
Property, plant and equipment (a, f, g, h)	1,778	(75)	532	2,235
	4,216	(98)	533	4,651
Total assets	$ 4,741	$ (119)	$ 532	$ 5,154
Current liabilities:				
Trade and other payables[2] (a, i)	$ 241	$ (7)	$ (16)	$ 218
Loans and borrowings	225	-	-	225
Deferred revenue (h)	1	-	10	11
Provisions (i)	-	-	16	16
Other liabilities	31	-	-	31
	498	(7)	10	501
Non-current liabilities:				
Loans and borrowings (j)	1,692	(5)	-	1,687
Deferred revenue (g, h)	-	(17)	522	505
Provisions (a, i, k)	-	-	37	37
Other liabilities (i)	81	-	(37)	44
	1,773	(22)	522	2,273
Total liabilities	2,271	(29)	532	2,774
Equity attributable to the Owner of the Company:				
Share capital	24	-	-	24
Accumulated other comprehensive income (loss) (e, j, l, m)	(16)	28	-	12
Retained earnings (a, e, f, h, k, l, m)	2,462	(118)	-	2,344
Total equity	2,470	(90)	-	2,380
Total liabilities and equity	$ 4,741	$ (119)	$ 532	$ 5,154

Reconciliation of equity reported under CGAAP to equity under IFRS at December 31, 2010:

($ millions)	CGAAP	Measurement adjustments	Presentation adjustments	IFRS
Current assets:				
Cash and cash equivalents	$ 104	$ -	$ -	$ 104
Trade and other receivables[1] (a)	519	(13)	-	506
Inventories	10	-	-	10
Deferred tax assets (b)	1	-	(1)	-
	634	(13)	(1)	620
Non-current assets:				
Other assets (a, c, d)	178	(2)	(176)	-
Finance lease receivables (c)	-	-	130	130
Other financial assets (c)	419	-	44	463
Deferred tax assets (b)	41	-	1	42
Investment in Capital Power (e)	1,235	(43)	-	1,192
Intangible assets (d, f)	100	(2)	2	100
Property, plant and equipment (f, g, h)	1,907	(80)	558	2,385
	3,880	(127)	559	4,312
Total assets	$ 4,514	$ (140)	$ 558	$ 4,932
Current liabilities:				
Trade and other payables[2] (a, i)	$ 279	$ 4	$ (24)	$ 259
Loans and borrowings	219	-	-	219
Deferred revenue (h)	3	-	9	12
Provisions (i)	-	-	24	24
Other liabilities	33	-	-	33
	534	4	9	547
Non-current liabilities:				
Loans and borrowings (j)	1,456	(3)	-	1,453
Deferred revenue (g, h)	-	(17)	549	532
Deferred tax liabilities	1	-	-	1
Provisions (a, i, k)	-	(1)	28	27
Other liabilities (i)	58	-	(28)	30
	1,515	(21)	549	2,043
Total liabilities	2,049	(17)	558	2,590
Equity attributable to the Owner of the Company:				
Share capital	24	-	-	24
Accumulated other comprehensive income (loss) (e, j, l, m)	(18)	23	-	5
Retained earnings (a, e, f, h, k, l, m)	2,459	(146)	-	2,313
Total equity	2,465	(123)	-	2,342
Total liabilities and equity	$ 4,514	$ (140)	$ 558	$ 4,932

(1) Trade and other receivables include accounts receivable, income taxes recoverable, prepaid expenses and the current portion of long-term receivables.

(2) Trade and other payables include accounts payable and accrued liabilities and income taxes payable.

Notes to the reconciliations:

(a) IFRS does not currently contain any separate guidance relating to recognition of assets and liabilities that have arisen as a result of rate regulation. Under current IFRS, such items were not recognized on transition. The impact of this at January 1, 2010 was to reduce trade and other receivables by $21 million, other assets by $1 million, PP&E by $1 million, trade and other payables by $7 million and non-current provisions by $2 million with a charge to retained earnings of $14 million. At December 31, 2010, the impact was to reduce trade and other receivables by $13 million, other assets by $2 million and non-current provisions by $2 million and increase trade and other payables by $4 million with a $17 million charge to retained earnings.

(b) In accordance with IAS 12 - Income Taxes, all deferred tax balances are classified as non-current, irrespective of the underlying assets or liabilities to which they relate, or the expected reversal of the temporary difference. The effect was to reclassify $1 million at January 1, 2010 and December 31, 2010 from current deferred tax assets to non-current deferred tax assets.

(c) In accordance with IAS 1 - Financial Statements (IAS 1), financial assets should be separately presented from other assets. The effect was to reclassify $161 million at January 1, 2010 and $174 million at December 31, 2010 from other assets. At January 1, 2010, $124 million is presented as finance lease receivables and $37 million is presented as other financial assets. At December 31, 2010, $130 million is presented as finance lease receivables and $44 million is presented as other financial assets.

(d) In accordance with IAS 1, goodwill should be presented either on the face of the consolidated statement of financial position or as part of intangible assets. Under CGAAP, goodwill was presented as part of other assets. The effect was to reclassify $2 million at January 1, 2010 and December 31, 2010 from other assets to intangible assets.

(e) The Company has restated its investment in Capital Power to recognize its equity share of Capital Power’s IFRS adjustments. The impact was a reduction in the investment of $20 million at January 1, 2010 and $43 million at December 31, 2010, an increase in accumulated other comprehensive income by $10 million at January 1, 2010 and by $6 million at December 31, 2010 and a charge to retained earnings of $30 million at January 1, 2010 and $49 million at December 31, 2010.

(f) The Company previously accounted for certain transactions in accordance with applicable rate regulation (regulatory accounting). As permitted previously under CGAAP, the Company applied Financial Accounting Standards Codification Section 980 – Regulated Operations, as issued by the Financial Accounting Standards Board in the U.S. as another source of Generally Accepted Accounting Principles.

Under regulatory accounting, gains and losses on the disposal of the Company’s rate-regulated assets were previously deferred within PP&E or intangible assets. The Company also previously capitalized non-directly attributable overhead within PP&E and intangible assets where it was included within the Company’s rate-regulated asset base.

Under IAS 16 - Property, Plant and Equipment (IAS 16) and IAS 38 – Intangible Assets (IAS

38), assets are required to be derecognized on disposal and any associated gain or loss should be recognized in net income. Overhead may only be capitalized where it is considered to be directly attributable to the construction of the asset.

The effect of this was to reduce the net book value of PP&E by $59 million at January 1, 2010 and $65 million at December 31, 2010. Intangible assets were reduced by $2 million at January 1, 2010 and December 31, 2010. The overall reduction in retained earnings was $61 million at January 1, 2010 and $67 million at December 31, 2010.

(g) Although the determination of whether an arrangement contains a lease is broadly similar between CGAAP and IFRS, CGAAP contained more quantitative criteria in determining whether a lease is treated as capital or operating. As a result, a lease agreement which was set up as a capital asset with deferred revenue offset under CGAAP, was determined to be a finance lease with a net balance of zero under IAS 17 – Leases. The impact was a reduction in PP&E of $15 million at January 1, 2010 and December 31, 2010, which was offset by a reduction in deferred revenue of $15 million at January 1, 2010 and December 31, 2010.

(h) Under CGAAP, contributions that were received from developers and customers and used to construct items of PP&E were offset against the cost of the constructed asset. Under International Financial Reporting Interpretations Committee (IFRIC) 18 - Transfers of Assets from Customers (IFRIC 18), contributions received in order to construct an item of PP&E that is used to provide ongoing access to electricity and water are treated as deferred revenues. The effect of this was to reclassify $532 million at January 1, 2010 and $558 million at December 31, 2010 from PP&E to deferred revenues.

In addition, $2 million at January 1, 2010 was recorded in net income relating to insurance proceeds that, under CGAAP, were being deferred and amortized over the life of the replacement asset. Under IAS 16 – Plant, Property and Equipment, such proceeds should be recognized in net income on settlement of the claim. The effect of this was to increase PP&E and retained earnings by $2 million at January 1, 2010 and December 31, 2010.

(i) Under IAS 1, provisions should be separately presented on the face of the consolidated statement of financial position. The effect was to reclassify $16 million at January 1, 2010 and $24 million at December 31, 2010 from trade and other payables to current provisions and to reclassify $37 million at January 1, 2010 and $28 million at December 31, 2010 from other non-current liabilities to non-current provisions.

(j) In accordance with IAS 39 – Financial Instruments: Recognition and Measurement (IAS 39), any asset that is classified as available-for-sale should be recorded at fair value, with any changes in fair value recognized in other comprehensive income. Under CGAAP, the Company's beneficial interest in the sinking fund is not quoted in an active market and was therefore recorded at cost. The impact was a reduction in loans and borrowings of $5 million at January 1, 2010 and $3 million at December 31, 2010 with a corresponding increase in accumulated other comprehensive income to recognize the difference between fair value and the CGAAP exchange amount.

(k) As permitted by IFRS 1 – First Time Adoption of International Financial Reporting Standards (IFRS 1), the Company has elected to recognize all cumulative actuarial gains and losses that existed at its date of transition in opening retained earnings for all of its employee benefit plans. The effect was to increase non-current provisions by $2 million at January 1, 2010 and by $1 million at December 31, 2010.

(l) As permitted by IFRS 1, the Company has elected to reset its cumulative translation account to nil at the date of transition. The impact of this was a reclassification of $19 million from accumulated other comprehensive income to retained earnings at January 1, 2010 and December 31, 2010.

(m) The Company recognized an increase in retained earnings of $6 million at January 1, 2010 and $5 million at December 31, 2010, offset by a decrease in accumulated other comprehensive income of $6 million at January 1, 2010 and $5 million at December 31, 2010 to reflect the deferred tax impact of the adjustments noted above relating to the Company's entities subject to income tax.

Reconciliation of total comprehensive income reported under CGAAP to total comprehensive income under IFRS for the year ended December 31, 2010:

($ millions)	CGAAP	Measurement adjustments	Presentation adjustments	IFRS
Revenues and other income (n, o)	$ 1,473	$ 4	$ 12	$ 1,489
Electricity purchases and system access fees (n)	(746)	(2)	-	(748)
Operations, maintenance and administration (p)	(366)	-	366	-
Other raw materials and operating charges (p, r)	-	(1)	(115)	(116)
Staff costs and employee benefits (p)	-	-	(222)	(222)
Depreciation and amortization (o, q)	(88)	2	(12)	(98)
Franchise fees and property taxes (n)	(61)	(6)	-	(67)
Other administrative expenses (p, r)	-	(6)	(29)	(35)
Operating income	212	(9)	-	203
Finance expense (s)	(127)	1	-	(126)
Equity share of income of Capital Power (t)	88	(33)	-	55
Loss on sale of a portion of investment in Capital Power and other (t)	(33)	14	-	(19)
Net income before income taxes	140	(27)	-	113
Income tax expense (u)	(7)	(1)	-	(8)
Net income	133	(28)	-	105
Other comprehensive loss:				
Unrealized loss on Available-for-sale financial assets (v)	-	(1)	-	(1)
Equity share of other comprehensive loss of Capital Power (t)	(4)	1	-	(3)
Loss realized in net income upon sale of a portion of investment in Capital Power (t)	2	(5)	-	(3)
Other comprehensive loss	(2)	(5)	-	(7)
Total comprehensive income – all attributable to the Owner of the Company	$ 131	$ (33)	$ -	$ 98

Notes to the reconciliations:

(n) As identified in note (f), the Company previously used regulatory accounting to recognize certain assets, liabilities, revenues and expenses. As a result, the timing of the Company's recognition of certain revenues and expenses differed from IFRS, which requires that revenues and expenses are recognized as incurred. For the year ended December 31, 2010, the impact was an increase in revenues of $4 million, an increase in electricity purchases and system access fees of $2 million, and an increase in franchise fees and property taxes of $6 million for an overall reduction in net income of $4 million.

(o) Under CGAAP, the amortization of contributions received towards the construction of PP&E used to provide ongoing access to electricity and water supply was treated as depreciation. Under IFRIC 18, such amortization is treated as revenue. The effect was to reclassify $12 million from depreciation to revenues for the year ended December 31, 2010.

(p) Under IAS 1, expenses must be presented using either a functional presentation or according to their nature. The Company has adopted presentation by nature. The effect was to reclassify salary, wages and employee benefit costs of $222 million to staff costs and employee benefits from operations, maintenance and administration for the year ended December 31, 2010. The remaining operations, maintenance and administrative costs were reclassified as other raw material and operating charges and other administrative expenses.

(q) As identified in note (f), PP&E and intangible assets have been adjusted for the removal of non-directly attributable overhead and deferred gains and losses on derecognized assets. As a result of this, and as a result of the review of the useful lives of the components of the Company's assets as required by IAS 16, there was a reduction in depreciation and amortization of $6 million offset by an additional $4 million loss on disposal of assets for the year ended December 31, 2010.

(r) Under CGAAP, overheads are capitalized as part of PP&E or intangible assets if they are permitted or required to be included in the Company's rate-regulated asset base. Under IAS 16 and IAS 38, overheads may only be capitalized if they are directly attributable to the construction of PP&E or intangible assets. The effect of this was an increase to other administrative expenses of $6 million combined with an increase of $1 million to other raw materials and operating charges for the year ended December 31, 2010.

(s) Under CGAAP, an allowance for funds used during construction was capitalized if it was approved or required by the regulator to be included in the Company's rate-regulated asset base. Under IAS 23 – Borrowing Costs, there are more detailed rules on the methodology for capitalizing borrowing costs. As a result of the change in methodology, the Company recognized an increase in capitalized interest of $1 million for the year ended December 31, 2010.

(t) The Company's income from its equity investment in Capital Power was decreased by $33 million for the year ended December 31, 2010 which reflected the Company's equity share of the adjustments recognized on transition to IFRS by Capital Power. The Company's other comprehensive income from the investment in Capital Power was increased by $1 million for the year ended December 31, 2010.

As a result of the restatement of the investment in Capital Power, the loss recognized in net income on disposal of a portion of interest in Capital Power was reduced by $14 million for the year ended December 31, 2010 and losses transferred to net income from other comprehensive income on disposal of a portion of interest in Capital Power were reduced by $5 million.

(u) As a result of the adjustments above, the Company recognized an increase in income tax expense of $1 million for the year ended December 31, 2010.

(v) As identified in note (j), the Company's beneficial interest in the sinking fund is measured at fair value under IFRS. As a result, the Company recognized a decrease in other comprehensive income of $1 million for the year ended December 31, 2010.

Reconciliation of operating income for the Company's segments for the year ended December 31, 2010 reported under CGAAP to operating income reported under IFRS:

Water Services

(unaudited, $ millions)	**CGAAP** restated*	**Measurement adjustments**	**Presentation adjustments**	**IFRS**
(including intersegment transactions)				
Revenues	$ 302	$ -	$ 8	$ 310
Expenses	238	-	8	246
Operating income	**$ 64**	**$ -**	**$ -**	**$ 64**

* Water Services' operating income for 2010 was restated reflecting the transfer of the management of Technologies from Water Services to Distribution and Transmission.

Water Services' operating income had no material measurement adjustments for the year ended December 31, 2010 in converting to IFRS. The presentation adjustments relate to amortization of customer and other contributions considered to be recognized deferred revenue under IFRIC 18. Under CGAAP, these amounts were included as an offset to depreciation expense, resulting in a reclassification of $8 million from depreciation expense to revenue for the year ended December 31, 2010.

Water Services' results for the year ended December 31, 2010 have been restated for comparative purposes to reflect a decrease of $72 million in revenue and a decrease of $62 million in expenses due to the transfer of the management of Technologies from Water Services to Distribution and Transmission in the third quarter of 2011.

Distribution and Transmission

(unaudited, $ millions)	**CGAAP** restated*	**Measurement adjustments**	**Presentation adjustments**	**IFRS**
(including intersegment transactions)				
Revenues	$ 384	$ -	$ 4	$ 388
Expenses	315	14	4	333
Operating income	**$ 69**	**$ (14)**	**$ -**	**$ 55**

* Distribution and Transmission's operating income for 2010 was restated reflecting the transfer of the management of Technologies from Water Services to Distribution and Transmission.

Distribution and Transmission's operating income had the following changes for the year ended December 31, 2010 due to the conversion to IFRS:

- The measurement adjustments primarily relate to expenses recognized under IFRS as incurred, rather than deferred until approved by the regulator under CGAAP.

- The presentation adjustments relate to the amortization of customer and other contributions. Under CGAAP, these amounts were included as an offset to depreciation expense. Under IFRIC 18, these amounts are considered to be recognized deferred revenue, resulting in a reclassification of $4 million from depreciation expense to revenue for the year ended December 31, 2010.

Distribution and Transmission's results for the year ended December 31, 2010 have been restated for comparative purposes to reflect an increase of $69 million in revenue and an increase of $59 million in expenses due to the transfer of the management of Technologies from Water Services to Distribution and Transmission in the third quarter of 2011.

Energy Services

(unaudited, $ millions)	**CGAAP**	**Measurement adjustments**	**Presentation adjustments**	**IFRS**
(including intersegment transactions)				
Revenues	$ 872	$ -	$ -	$ 872
Expenses	842	3	-	845
Operating income	**$ 30**	**$ (3)**	**$ -**	**$ 27**

Energy Services' operating income for the year ended December 31, 2010 was adjusted for expenses recognized as incurred under IFRS, rather than deferred until approved by the regulator under CGAAP.

Impact on Future Reporting

As a result of the transition to IFRS from CGAAP, we expect the following changes to future reporting:

- Under CGAAP, overhead expenses were capitalized as part of PP&E or intangible assets if they were permitted or required to be included in the Company's rate-regulated asset base. Under IFRS, overheads may only be capitalized if they are directly attributable to the construction of PP&E or development of intangible assets. The effect of this difference is that net income, in the year the overheads are incurred, will be lower than previously reported under CGAAP but higher in later years, since there will be no depreciation expense on such costs as there would have been under CGAAP.
- The Company's beneficial interest in the sinking fund is required to be measured at fair value under IFRS. As a result, there will be increased volatility in comprehensive income, which will diminish over time as the associated debt is repaid.
- Under CGAAP, the amortization of contributions received towards the construction of PP&E used to provide ongoing access to electricity and water supply was treated as an offset to depreciation expense. Under IFRIC 18, these amounts are treated as revenue. This change will increase depreciation expense and increase revenue with no impact on net income.
- As regulatory assets and liabilities are not recognized under IFRS, amounts which were previously recognized under CGAAP, on the basis that regulatory approval would ultimately allow the amounts, will only be recognized when future rates are effective and the services have been provided to customers. Adoption of IFRS introduces timing differences in revenue recognition relative to these amounts and as a result, there will be increased volatility in net income.
- Currently, most of the Company's operations are rate-regulated, and impairments of assets subject to rate-regulation are not a significant concern under the current regulatory framework.

However, the Company's non-rate-regulated commercial operations are comprised of numerous cash generating units. As a result, the greater number of cash generating units and increased frequency of assessment for indicators of impairment under IFRS than under CGAAP may give rise to more frequent impairment charges than would otherwise be the case under CGAAP.

FUTURE ACCOUNTING STANDARD CHANGES

The following accounting standards and interpretations, which have potential significance to the Company, were issued by the International Accounting Standards Board (IASB) and the International Financial Reporting Interpretations Committees for application in future periods:

International Accounting Standards (IAS / IFRS)	Effective for annual periods beginning on or after:
IFRS 7 (Amendment) – Financial Instruments: Disclosures	July 1, 2011
IAS 1 (Amendment) – Presentation of Financial Statements	July 1, 2012
IFRS 9 – Financial Instruments	January 1, 2015
IFRS 10 – Consolidated Financial Statements	January 1, 2013
IFRS 11 – Joint Arrangements	January 1, 2013
IFRS 12 – Disclosure of Interests in Other Entities	January 1, 2013
IFRS 13 – Fair Value Measurement	January 1, 2013
IAS 28 (Amendment) – Investments in Associates and Joint Ventures	January 1, 2013
IFRS 7 (Amendment) – Disclosures – Offsetting Financial Assets and Liabilities	January 1, 2013
IAS 32 – Financial Instruments: Presentation	January 1, 2014

IFRS 7 (Amendment) – Financial Instruments: Disclosures

This amendment requires additional disclosure with respect to transferred assets that are not derecognized and financial assets which have been derecognized but for which the entity is still involved. The Company does not expect the amendments to have a material impact on the financial statements, because of the nature of the Company's operations and the types of financial assets that it holds.

IAS 1 (Amendment) – Presentation of Financial Statements (IAS 1)

The amendment requires entities to group items presented in other comprehensive income (OCI) on the basis of whether they might at some point be reclassified from OCI to profit or loss at a later date when specified conditions are met. By requiring items of OCI to be grouped on this basis, their potential effect on profit or loss in future periods will be clearer. The Company does not expect IAS 1 to have a material impact on the financial statements.

IFRS 9 – Financial Instruments (IFRS 9)

This standard replaces IAS 39 and eliminates the existing categories of financial assets and requires financial assets to be classified as either amortized cost or fair value. Gains and losses on re-measurement of financial assets at fair value will be recognized in profit or loss, except for an investment in an equity instrument which is not held-for-trading. Changes in fair value attributable to changes in credit risk of financial liabilities measured under the fair value option will be recognized in OCI with the remainder of the change recognized in profit or loss unless an accounting mismatch in profit or loss occurs at which time the entire change in fair value would be recognized in profit or loss.

Derivative liabilities that are linked to and must be settled by delivery of an unquoted equity instrument must be measured at fair value. The impact on the Company of adoption of IFRS 9 has not yet been determined.

IFRS 10 - Consolidated Financial Statements (IFRS 10)

This standard replaces IAS 27 – Consolidated and Separate Financial Statements and Standing Interpretations Committee (SIC) – 12 – Consolidation – Special Purpose Entities (SIC-12) and provides a single model to be applied in the control analysis for all investees, including entities that currently are special purpose entities in the scope of SIC-12. The Company does not expect this standard to have a material impact on its financial statements as it does not change the control analysis for any of its associates or subsidiaries.

IFRS 11 – Joint Arrangements (IFRS 11)

This standard replaces IAS 31 - Interests in Joint Ventures and SIC-13 – Jointly Controlled Entities - Non-Monetary Contributions by Vendors. IFRS 11 draws a distinction between joint operations and joint ventures. Entities which previously accounted for joint ventures using proportionate consolidation will generally be required to account for such ventures using the equity method. The Company does not expect the amendment to have any impact on the current treatment of its joint venture.

IFRS 12 – Disclosure of Interest in Other Entities (IFRS 12)

This standard contains the disclosure requirements for entities that have interests in subsidiaries, joint arrangements, associates and / or unconsolidated structured entities. When applied, it is expected that the amendments to IFRS 12 will increase the current level of disclosure of the Company's interest in other entities.

IFRS 13 – Fair Value Measurement (IFRS 13)

This standard replaces the fair value measurement guidance contained in individual IFRSs with a single source of fair value measurement guidance. It defines fair value, establishes a framework for measuring fair value and sets out disclosure requirements. The Company does not expect IFRS 13 to have a material impact on the financial statements.

IAS 28 (Amendment) – Investments in Associates and Joint Ventures

This standard was amended to conform to the IFRS 10 and IFRS 11 accounting standards. The amendments apply to the measurement of a retained stake in an investment where significant influence is succeeded by joint control, and to the measurement of a retained stake in an investment, a portion of which has been classified as held for sale. The Company does not expect these amendments to have any impact on the financial statements.

IFRS 7 – (Amendment) – Disclosures – Offsetting Financial Assets and Liabilities

This amendment requires additional disclosure when an entity has the right to offset financial assets and financial liabilities and has presented the net amount in the statement of financial position. The Company does not expect this amendment to have a material impact on the financial statements.

IAS 32 – Financial Instruments: Presentation

This standard provides additional guidance on the application of offsetting criteria. The Company does not expect this amendment to have a material impact on the financial statements.

In addition, the following projects on the IASB work-plan, with standards expected to be issued during

2012, may have an impact on the Company when adopted:

Leases

The IASB issued an exposure draft on leases which proposes recording all leased assets on the statement of financial position. EPCOR, as a lessee, is party to a number of leases, including a long-term commitment with respect to its head office and as part of its commercial water operations. EPCOR may also enter into arrangements where it is a lessor. These proposals could result in revised asset and liability amounts recorded on the statement of financial position and would alter the presentation of revenues and expenses associated with such contracts by reclassifying the related operating expenses as finance expense and depreciation expense, and related operating revenues as finance income.

Revenue Recognition

In November 2011 the IASB issued an exposure draft on revenue recognition to replace the current guidance contained in IAS 18 – Revenue and IAS 11 – Construction Contracts and to provide a single, consistent framework for revenue recognition. The exposure draft proposes a five step framework for recognizing revenue. As part of the single framework approach, the percentage of completion method used for construction contracts under IAS 11 – Construction Contracts is withdrawn, which could result in differences in the timing of revenue recognition on construction contracts if it is assessed that control does not continuously pass to the customer. In addition, the exposure draft contains more detailed guidance in identifying separate deliverables and in determining the transaction price.

The impact of these projects on the Company will be assessed once final standards have been issued.

CRITICAL ACCOUNTING ESTIMATES

In preparing the consolidated financial statements, management necessarily made estimates in determining transaction amounts and financial statement balances. The following are the items for which significant estimates were made in the financial statements.

Electricity Revenues, Costs and Unbilled Consumption

Due to the lag time between electricity consumption and receipt of final billing consumption information from the load settlement agents, the Company must use estimates for determining the amount of electricity consumed but not yet billed. These estimates affect accrued revenues and accrued electricity costs of the Energy Services segment. There are a number of variables in the computation of these estimates, and the underlying electricity settlement processes within EPCOR and the Alberta electric systems are complex. Owing to the factors above and the statutory delays in final load settlement determinations and information, adjustments to previous estimates could be material. Estimates for unbilled consumption averaged approximately $78 million at the end of each month in 2011 (2010 - $58 million) and these estimates varied from $57 million to $103 million (2010 - $45 million to $74 million). Adjustments of estimated revenues to actual billings were less than $5 million per month in 2011 (2010 - $5 million).

Fair Values

We are required to estimate the fair value of certain assets or obligations for determining the valuation of certain financial instruments, asset impairments, asset retirement obligations and purchase price allocations for business combinations, and for determining certain disclosures. Following are the descriptions of the key fair value methodologies relevant for 2011.

Fair values of financial instruments are based on quoted market prices when these instruments are traded in active markets. In illiquid or inactive markets, the Company uses appropriate price modeling to estimate fair value. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows and discount rates.

The Company reviews the valuation of long-lived assets subject to amortization when events or changes in circumstances may indicate or cause a long-lived asset's carrying amount to exceed the total undiscounted future cash flows expected from its use and eventual disposition. An impairment loss, if any, will be recorded as the excess of the carrying amount of the asset over its fair value, measured by either market value, if available, or estimated by calculating the present value of expected future cash flows related to the asset.

Estimates of fair value for long-lived asset impairments are mainly based on depreciable replacement cost or discounted cash flow techniques employing estimated future cash flows based on a number of assumptions, including the selection of an appropriate discount rate. The cash flow estimates will vary with the circumstances of the particular assets or reporting unit and will primarily be based on the lives of the assets revenues and expenses, including inflation, and required capital expenditures.

Allowance for Doubtful Accounts

We continually review our aged accounts receivable and assess the underlying credit quality of our customers and counterparties. The allowance for doubtful accounts reflects an estimate of the accounts receivable that are ultimately expected to be uncollectible. It is principally based on the aging of receivables, historical write-offs within customer groups, assessments of the collectability of amounts from individual customers and general economic conditions. EPCOR's allowance account averaged $4 million (2010 - $3 million) and reported bad debts were $7 million (2010 - $5 million). The estimate of the allowance affects accounts receivable and all segments' other administrative expenses.

Useful Lives of Assets

Depreciation and amortization allocate the cost of assets over their estimated useful lives on a systematic and rational basis. Depreciation and amortization also include amounts for future decommissioning costs and asset retirement obligation accretion expenses. Estimating the appropriate useful lives of assets requires significant judgment and is generally based on estimates of common life characteristics of common assets.

Income Taxes

EPCOR follows the asset and liability method of accounting for income taxes. Income taxes are determined based on estimates of our current taxes and estimates of deferred taxes resulting from temporary differences between the carrying values of assets and liabilities in the financial statements and their tax values. Deferred tax assets are assessed to determine the probability that they will be recovered from future taxable income. To the extent recovery is not probable, a deferred tax asset is not recognized. Estimates of the provision for income taxes and deferred tax assets and liabilities might vary from actual amounts incurred.

Fair values and useful lives are used in determining potential impairments for each long-lived asset, which will vary with each asset and market conditions at the particular time. Similarly, income taxes will vary with taxable income and, under certain conditions, with fair values of assets and liabilities. Accordingly, it is not possible to provide a reasonable quantification of the range of these estimates that would be meaningful to readers.

Impact of Current Market Conditions on Estimates

Although the current condition of the economy has not impacted our methods of estimating accounting values, it has impacted the inputs in those determinations and the resulting values. Future cash flow estimates for assessing long-lived assets for impairment were updated to reflect any increased uncertainties of recoverability. The assessments did not result in any impairment losses because a large portion of the Company's long-lived assets are subject to rate-regulation. Similarly, the assessment of the useful lives of our long-lived assets did not change since many of our distribution and transmission assets and water assets located in the City and surrounding area are amortized based on rates approved by the applicable regulator. Our valuation models for estimating the fair value of long-lived asset impairments depend partly on discount rates which were updated to reflect changes in credit spreads and market volatility. Our methods for determining the allowance for doubtful accounts are based on historical rates of bad debts in relation to the aged accounts receivable balances by customer group for RRT and default customer bases. These analyses did not reveal any significant changes in our assessment of the recoverability of accounts receivable at December 31, 2011.

NON-IFRS FINANCIAL MEASURES

We use funds from operations to measure the Company's ability to generate funds from current operations. Funds from operations is a non-IFRS financial measure, does not have any standardized meaning prescribed by IFRS and is unlikely to be comparable to similar measures published by other entities. However, it is presented since it is commonly referred to by debt holders and other interested parties in evaluating the Company's financial position and in assessing its creditworthiness. A reconciliation of funds from operations to cash flows from operating activities is as follows:

Years ended December 31, ($ millions)	**2011** IFRS	**2010** IFRS	**2009** CGAAP
Funds from operations	**$ 208**	**$ 193**	**$ 356**
Change in non-cash operating working capital	(85)	(3)	(54)
Cash flows from operating activities	**$ 123**	**$ 190**	**$ 302**

Net income from core operations is used to distinguish operating results from the Company's core water and electricity businesses from results with respect to its investment in Capital Power. It is a non-IFRS financial measure, which does not have any standardized meaning prescribed by IFRS and is unlikely to be comparable to similar measures published by other entities. However, it is presented since it provides a useful measure of the company's primary operations, it is referred to by debt holders and other interested parties in evaluating the Company's financial position and in assessing its creditworthiness. A reconciliation of net income from core operations to net income is as follows:

Years ended December 31, ($ millions)	**2011**	**2010**
Net income from core operations	**$ 78**	**$ 70**
Loss on sale of a portion and net gain on dilutions of investment in Capital Power	(24)	(19)
Equity income from Capital Power	90	55
Income tax recoveries related to the above items	-	(1)
Net income	**$ 144**	**$ 105**

FINANCIAL INSTRUMENTS

The Company classifies its cash and cash equivalents and current and non-current derivative instruments assets and liabilities as held at fair value through profit or loss and measures them at fair value. Accounts receivable are classified as loans and receivables, short-term loans and borrowings, accounts payable and accrued liabilities, and other current liabilities are classified as other financial liabilities all of which are measured at amortized cost and their fair values are not materially different from their carrying amounts due to their short term nature. The Company's beneficial interest in the sinking fund related to the City debentures is classified as available-for-sale and measured at fair value. The transfer fee payable relating to the Gold Bar transfer, which is included in other non-current liabilities and other current liabilities, is classified as another financial liability measured at amortized cost.

The classification, carrying amounts and fair values of the Company's other financial instruments held at December 31, 2011 and December 31, 2010 were as follows:

December 31, 2011	**Carrying amount**					
($ millions)	**Fair value through profit or loss**	**Available-for-sale**	**Loans and receivables**	**Other financial liabilities**	**Total**	**Total fair value**
Cash and cash equivalent	$ 316	$ -	$ -	$ -	$ 316	$ 316
Finance lease receivables	-	-	130	-	130	145
Other financial assets (including current portion)	-	-	431	-	431	487
Loans and borrowings (including current portion)	-	(244)	-	1,943	1,699	2,084

December 31, 2010	**Carrying amount**					
($ millions)	**Fair value through profit or loss**	**Available-for-sale**	**Loans and receivables**	**Other financial liabilities**	**Total**	**Total fair value**
Cash and cash equivalent	$ 104	$ -	$ -	$ -	$ 104	$ 104
Finance lease receivables	-	-	133	-	133	171
Other financial assets	42	-	658	-	700	722
Loans and borrowings (including current portion)	-	(294)	-	1,966	1,672	1,941

Loans and borrowings include the City debentures which are offset by the payments made by the

Company into the sinking fund. Although the accumulated contributions to the sinking fund are classified as available-for-sale, they are included as an offset to long-term debt under other financial liabilities in the table above, consistent with their presentation on the balance sheet. The accumulated contributions to the sinking fund are measured at fair value.

The fair values of the Company's net investments in leases, included in finance lease receivables above, are based on the estimated interest rates implicit in comparable lease arrangements or loans plus an estimated credit spread based on the counterparty risk as at December 31, 2011 and December 31, 2010.

OTHER COMPREHENSIVE INCOME

For the year ended December 31, 2011, the Company's transactions in other comprehensive income included the Company's share of other comprehensive loss of Capital Power of $4 million (2010 - $3 million) and the reclassification to net income of retained power generation business accumulated other comprehensive income upon the sale of a portion of and dilutions of the investment in Capital Power of $5 million (2010 - $3 million of other comprehensive loss).

RELATED PARTY TRANSACTIONS

EPCOR enters into various transactions with its sole shareholder, the City, and with Capital Power. These transactions are in the normal course of operations and are recorded at the exchange value generally based on normal commercial rates or as agreed to by the parties.

We recorded finance expenses of $25 million in 2011 (2010 - $34 million) on EPCOR's debt obligation to the City. This debt obligation includes debt capital issued by the City prior to 1996 when EPCOR commenced raising capital directly. The decrease in interest expense in 2011 corresponds to the decrease in the net obligation as a result of repayments of principal amounts in 2011 and 2010. The outstanding balance of the net obligation to the City was $172 million at December 31, 2011 (2010 - $205 million). There were $50 million (2010 – $61 million) in trade and other payables and loans and borrowings to the City, including $29 million (2010 – $43 million) related to Gold Bar transfer fee payables. There were $20 million (2010 – nil) in deferred revenue related to contributions received for capital projects and rebates relating to maintenance, repair and construction services.

Sales from EPCOR to the City included electricity and water, and the provision of maintenance, repair, construction and customer care services totaling $90 million in 2011 (2010 - $80 million). We paid franchise fees and property taxes to the City of $76 million (2010 - $66 million). The City provided miscellaneous services to EPCOR totaling $14 million (2010 - $13 million).

We recorded financing revenues of $23 million in 2011 (2010 – $51 million) on the long-term loans receivable from Capital Power. The outstanding balance of the long-term loans receivable at December 31, 2011 was $379 million (2010 – $613 million).

Sales from EPCOR to Capital Power included electricity sales of $23 million in 2011 (2010 – $30 million) at normal commercial rates. Electricity purchases by EPCOR from Capital Power were $230 million in 2011 (2010 – $360 million). These transactions relate to EPCOR's EPSP prior to July 2011 when Capital Power was our sole counterparty for these services. We recorded $6 million (2010 – $6 million) in services income from Capital Power. We also recorded $7 million (2010 – $9 million) in utility and services charges from Capital Power. We had $2 million of trade and other payables to Capital Power, primarily related to utility and services charges, at December 31, 2011 (2010 – $46 million primarily related to electricity purchases under the previous EPSP). Trade and other receivables included $22 million (2010 – $28 million) for uncollected amounts related to services provided to Capital Power and accrued interest on long-term loans receivable from Capital Power. Transition services transactions are primarily for general shared service administrative functions and were completed by the end of 2011.

The Company has $7 million (2010 – $7 million) in deferred revenue from Capital Power for the construction of aerial and underground transmission lines.

Equity in the income of Capital Power, including equity in other comprehensive income, was $85 million in 2011 (2010 – $51 million).

FOURTH QUARTER REVIEW AND QUARTERLY RESULTS

(unaudited, $ millions) **Quarters ended**	**Revenues**	**Net income (loss)**
December 31, 2011	$ 512	$ 53
September 30, 2011	480	59
June 30, 2011	391	23
March 31, 2011	411	9
December 31, 2010	383	6
September 30, 2010	377	26
June 30, 2010	350	(10)
March 31, 2010	329	83

For the quarter ended December 31, 2011, consolidated net income increased by $47 million from the corresponding quarter in the prior year primarily due to a higher equity share in income of Capital Power, increased income in Distribution and Transmission primarily due to increased rates and a lower loss on disposal of a portion of the interest in Capital Power, partially offset by a negative fair value adjustment on foreign exchange contracts and integration expenses relating to Chaparral, Arizona Water and New Mexico Water.

Events for 2011 and 2010 quarters that have significantly impacted net income and cash flows and the comparability between quarters are:

- September 30, 2011 third quarter results included higher equity share in income of Capital Power, positive fair value adjustment on foreign exchange contracts, lower Energy Services operating income primarily due to negative fair value adjustments on financial electricity purchase contracts, lower Water Services operating income due to higher maintenance and chemical costs and lower commercial services margins, and higher Distribution and Transmission operating income primarily due to increased transmission and distribution tariff rates.
- June 30, 2011 second quarter results included higher equity share in income of Capital Power , a gain on sale of our floating-rate notes, higher Energy Services operating income primarily due to positive fair value adjustments on financial electricity purchase contracts, lower Water Services operating income due to higher maintenance and chemical costs and lower commercial services margins and lower Distribution and Transmission operating income primarily due to higher electricity system operator costs.
- March 31, 2011 first quarter results included lower equity in the net income of Capital Power due to our reduced investment and lower Capital Power net income, lower Water Services operating income and higher Distribution and Transmission operating income.

- December 31, 2010 fourth quarter results included the loss on sale of a portion of the investment in Capital Power and lower revenues due to the sale of the power generation business in 2009, partially offset by operating income as a result of increased rates in Distribution and Transmission and Energy Services, transfer of Gold Bar on March 31, 2009, the acquisition of Alberta oil sands related water and wastewater treatment operations in the fourth quarter of 2009 and interest revenue on the long-term loans receivable from Capital Power.
- September 30, 2010 third quarter results included positive operating income as a result of the transfer of Gold Bar on March 31, 2009, the acquisition of Alberta oil sands related water and wastewater treatment operations in the fourth quarter of 2009, our equity share of income of Capital Power, lower revenues due to the sale of the power generation business in 2009, and interest revenue on the long-term loans receivable from Capital Power.
- June 30, 2010 second quarter results included our equity share of loss of Capital Power, lower revenues due to the sale of the power generation business in 2009, interest revenue on the long-term loans receivable from Capital Power, positive operating income as a result of the transfer of Gold Bar on March 31, 2009 and the acquisition of Alberta oil sands related water and wastewater treatment operations in the fourth quarter of 2009.
- March 31, 2010 first quarter results included our equity share of income of Capital Power, lower revenues due to the sale of the power generation business in 2009, interest revenue on the long-term loans receivable from Capital Power, positive operating income as a result of the transfer of Gold Bar on March 31, 2009 and the acquisition of Alberta oil sands related water and wastewater treatment operations in the fourth quarter of 2009.

FORWARD - LOOKING INFORMATION

Certain information in this MD&A is forward-looking within the meaning of Canadian securities laws as it relates to anticipated financial performance, events or strategies. When used in this context, words such as “will”, “anticipate”, “believe”, “plan”, “intend”, “target”, and “expect” or similar words suggest future outcomes.

The purpose of forward-looking information is to provide investors with management’s assessment of future plans and possible outcomes and may not be appropriate for other purposes. Forward-looking information in this MD&A includes: (i) long-term outlook for electricity, water and wastewater services in North America and the requirement for new electricity transmission infrastructure in Alberta; (ii) the Company’s growth plans and expected future investment opportunities; (iii) expectations regarding future regulatory proceedings, decisions and filings and their potential impact on the Company; (iv) revenue, net income and operating cash flow expectations for 2012 and the expected items giving rise to them; (v) projected capital spending requirements for 2012 and expected sources of funding; (vi) expected sources of financing of future acquisitions; (vii) expectations regarding the Company’s creditworthiness, liquidity, credit rating and potential impact of a credit rating downgrade; (viii) expected timeframes and amounts to settle existing contractual obligations; (ix) expectations regarding the timing and completion of specific capital projects; and (x) anticipated changes in IFRS subsequent to adoption on January 1, 2011.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions and expected future developments and other factors it believes are appropriate. The material factors and assumptions underlying this forward-looking information include, but are not limited to: (i) the operation of the

Company’s facilities; (ii) the Company’s assessment of the markets and regulatory environments in which it operates; (iii) weather; (iv) availability and cost of labor and management resources; (v) performance of contractors and suppliers; (vi) availability and cost of financing; (vii) foreign exchange rates; (viii) management’s analysis of applicable tax legislation; (ix) the currently applicable and proposed tax laws will not change and will be implemented; (x) counterparties will perform their obligations; (xi) expected interest rates and related credit spreads; (xii) ability to implement strategic initiatives which will yield the expected benefits; (xiii) the Company’s assessment of capital markets; and (xiv) factors and assumptions in addition to the above related to the Company’s equity interest in Capital Power.

Whether actual results, performance or achievements will conform to the Company’s expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results and experience to differ materially from EPCOR’s expectations. The primary risks and uncertainties relate to: (i) operation of the Company’s facilities; (ii) unanticipated maintenance and other expenditures; (iii) electricity load settlement; (iv) regulatory and government decisions including changes to environmental, financial reporting and tax legislation; (v) weather and economic conditions; (vi) competitive pressures; (vii) construction; (viii) availability and cost of financing; (ix) foreign exchange; (x) availability of labor and management resources; (xi) performance of counterparties, partners, contractors and suppliers in fulfilling their obligations to the Company; (xii) availability and price of electricity; (xiii) customer consumption volumes of water and electricity; and (xiv) risks in addition to the above related to the Company’s equity interest in Capital Power, including power plant availability and performance.

This MD&A includes the following updates to previously issued forward-looking statements: (i) expected quarterly distributions from Capital Power L.P. decreased from previously disclosed $15 million to $12 million due to the sale of a portion of our interest during 2011; (ii) expected cash flow from operating activities for the year ended December 31, 2011 was previously disclosed to be higher than 2010, but actual cash flow from operating activities decreased from 2010 due to lower income from operations; and (iii) the Company now expects to file its Energy Services cost of service rate application, for 2012 and 2013, in the second quarter of 2012 instead of the first quarter of 2012 as previously expected.

Readers are cautioned not to place undue reliance on forward-looking statements as actual results could differ materially from the plans, expectations, estimates or intentions expressed in the forward-looking statements. Except as required by law, EPCOR disclaims any intention and assumes no obligation to update any forward-looking statement even if new information becomes available, as a result of future events or for any other reason.

ADDITIONAL INFORMATION

Additional information relating to EPCOR including the Company’s 2011 Annual Information Form is available on SEDAR at www.sedar.com.