FORTIS INC.

Second Quarter 2011

Dear Shareholder:

Fortis achieved second quarter net earnings attributable to common equity shareholders of $58 million, or $0.33 per common share, compared to $55 million, or $0.32 per common share, for the second quarter of 2010. Net earnings attributable to common equity shareholders for the first half of 2011 were $175 million, or $1.00 per common share, up $20 million from earnings of $155 million, or $0.90 per common share, for the first half of last year.

Canadian Regulated Electric Utilities contributed earnings of $45 million, up $5 million from the second quarter of 2010. The increase reflected improved results at the electric utilities in western Canada associated with overall growth in utility infrastructure investment, lower market-priced purchased power costs at FortisBC Electric and additional return earned on FortisAlberta's investment in automated meters.

Canadian Regulated Gas Utilities contributed earnings of $15 million compared to $17 million for the second quarter of 2010. The decrease in earnings was mainly attributable to the timing of operating expenses, partially offset by the impact of growth in utility infrastructure investment and higher gas delivery volumes in the forestry sector. Due to the seasonality of the business, most of the earnings of the gas utilities are realized in the first and fourth quarters.

The average monthly run rate for the Corporation's 2011 capital program is approximately $100 million, more than 80% of which is being driven by the regulated utilities in western Canada and the Corporation's non-regulated Waneta hydroelectric generation expansion project in British Columbia (the "Waneta Expansion Project"), in which Fortis holds a 51% controlling interest. Gross capital expenditures for the first half of 2011 totalled $519 million. Several capital projects which commenced prior to 2011 are being completed this year. During the second quarter FortisBC's gas business substantially completed construction of its liquefied natural gas ("LNG") storage facility on Vancouver Island at an estimated cost of $214 million. The LNG storage facility is currently being filled and is expected to be available for the upcoming winter heating season. FortisBC's electricity business expects to substantially complete its $105 million Okanagan Transmission Reinforcement Project later this year. FortisAlberta has substantially completed its $126 million Automated Metering Project, which involved the replacement of approximately 466,000 conventional meters. Work continues on the $900 million Waneta Expansion Project, which is expected to be completed in spring 2015.

With regard to regulatory matters, FortisBC recently filed two-year (2012-2013) rate applications for both its gas and electricity businesses. Earlier in the year, FortisAlberta filed a two-year (2012-2013) rate application, including proposed gross capital expenditures of more than $775 million over the two-year period.

Caribbean Regulated Electric Utilities contributed $7 million, consistent with earnings for the second quarter of 2010. Energy sales at Caribbean Utilities and Fortis Turks and Caicos continue to be impacted by the persistent challenging economic conditions being experienced in the region. Effective June 20, 2011, the Government of Belize (the "GOB") expropriated the Corporation's investment in Belize Electricity. Consequently, there will be no future earnings contribution to Fortis from Belize Electricity. Belize Electricity has contributed minimal earnings since mid-2008. In late July, Fortis, as part of its legal approach, initiated proceedings for compensation from the GOB for the value of the Corporation's previous investment in Belize Electricity. To date, the Corporation's non-regulated hydroelectric generating business in Belize, Belize Electric Company Limited ("BECOL"), has not been impacted by the GOB expropriation legislation.

Fortis Properties delivered earnings of $7 million compared to $8 million for the second quarter of 2010, reflecting lower occupancies at hotel operations in western Canada, combined with increased operating expenses.

Non-Regulated Fortis Generation contributed $2 million to earnings compared to $3 million for the second quarter of 2010. Results mainly reflected decreased production at BECOL due to lower rainfall.

Corporate and other expenses were $18 million, $2 million lower quarter over quarter, mainly due to reduced operating expenses. Higher operating expenses incurred in the second quarter of 2010 related to business development costs.

Cash flow from operating activities was $527 million for the first half of 2011, up $122 million from the first half of 2010, driven by higher earnings, the collection from customers of higher amortization costs and favourable changes in working capital and regulatory deferral accounts.

The Merger Agreement between Fortis and Central Vermont Public Service Corporation ("CVPS") announced on May 30, 2011 (the "Merger Agreement") was terminated in July, subsequent to quarter end. Pursuant to the terms of the Merger Agreement, CVPS paid Fortis a US$17.5 million termination fee plus US$2 million for expenses.

Fortis recently raised total gross proceeds of approximately $341 million from the public issuance of 9,100,000 common shares in June, and an additional 1,240,000 common shares in July upon the exercise of an over-allotment option by the underwriters. Net proceeds of the equity issue are being used to repay borrowings under credit facilities and finance equity injections into the utilities in western Canada and the Waneta Expansion Limited Partnership in support of infrastructure investment, and for general corporate purposes.

We are on track to complete our $1.2 billion 2011 capital expenditure program. Our five-year capital expenditure program out to the end of 2015 is forecasted to increase to $5.7 billion. This investment will ensure that Fortis continues to meet the energy needs of our customers.

We are disciplined and patient in our pursuit of electric and gas utility acquisitions in the United States and Canada that will add value for Fortis shareholders.

H. Stanley Marshall
President and Chief Executive Officer
Fortis Inc.

Interim Management Discussion and Analysis

For the three and six months ended June 30, 2011
Dated August 3, 2011

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FORWARD-LOOKING STATEMENT

The following Management Discussion and Analysis ("MD&A") should be read in conjunction with the Fortis Inc. ("Fortis" or the "Corporation") interim unaudited consolidated financial statements and notes thereto for the three and six months ended June 30, 2011 and the MD&A and audited consolidated financial statements for the year ended December 31, 2010 included in the Corporation's 2010 Annual Report. The MD&A has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations.* Financial information in the MD&A has been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") and is presented in Canadian dollars unless otherwise specified.

Fortis includes forward-looking information in the MD&A within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to the Corporation's management. The forward-looking information in the MD&A includes, but is not limited to, statements regarding: the expected timing of filing of regulatory applications and of receipt of regulatory decisions; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of cash from operations, borrowings under credit facilities, equity injections from Fortis and long-term debt issues; consolidated forecast gross capital expenditures for 2011 and in total over the five-year period 2011 through 2015; the expectation that the Corporation's significant capital expenditure program should drive growth in earnings and dividends; expected consolidated long-term debt maturities and repayments on average annually over the next five years; except for debt at Exploits River Hydro Partnership ("Exploits Partnership"), the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants during 2011; no material adverse credit rating actions are expected in the near term; and the expected impact of the transition to United States generally accepted accounting principles. The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major event; the expectation that the Corporation will receive compensation from the Government of Belize ("GOB") for the value of the Corporation's previous investment in Belize Electricity; the expectation that Belize Electric Company Limited ("BECOL") will not be expropriated by the GOB; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no material capital project and financing cost overrun related to the construction of the Waneta hydroelectric generation expansion project; no significant decline in capital spending in 2011; no severe and prolonged downturn in economic conditions; sufficient liquidity and capital resources; the continuation of regulator-approved mechanisms to flow through the commodity cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas commodity prices; no significant variability in interest rates; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas supply; the continued ability to fund defined benefit pension plans; the absence of significant changes in government energy plans and environmental laws that may materially affect the operations and *cash flows of the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; maintenance of information technology infrastructure; favourable relations with First Nations; favourable labour relations; and sufficient human resources to deliver service and execute the capital program. The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory risk; operating and maintenance risks; risk associated with the amount of compensation to be paid to Fortis for its previous investment in Belize Electricity; the timeliness of the receipt of the compensation and the ability of the GOB to pay the compensation owing to Fortis; risk that the GOB may expropriate BECOL; capital project budget overrun, completion and financing risk in the Corporation's non-regulated business; economic conditions; capital resources and liquidity risk; weather and seasonality; commodity price risk; derivative financial instruments and hedging; interest rate risk; counterparty risk; competitiveness of natural gas; natural gas supply; defined benefit pension plan performance and funding requirements; risks related to the development of the FortisBC Energy (Vancouver Island) Inc. franchise; environmental risks; insurance coverage risk; loss of licences and permits; loss of service area; changes in tax legislation; information technology infrastructure; an ultimate resolution of the expropriation of the assets of the Exploits Partnership that differs from what is currently expected by management; an unexpected outcome of legal proceedings currently against the Corporation; relations with First Nations; labour relations; and human resources. For additional information with respect to the Corporation's risk factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and to the heading "Business Risk Management" in the MD&A for the three and six months ended June 30, 2011 and for the year ended December 31, 2010.*

All forward-looking information in the MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

CORPORATE OVERVIEW

Fortis is the largest investor-owned distribution utility in Canada, serving approximately 2,000,000 gas and electricity customers. Its regulated holdings include electric utilities in five Canadian provinces and two Caribbean countries and a natural gas utility in British Columbia, Canada. Fortis owns non-regulated generation assets, primarily hydroelectric, across Canada and in Belize and Upper New York State, and hotels and commercial office and retail space primarily in Atlantic Canada. Year-to-date June 30, 2011, the Corporation's electricity distribution systems met a combined peak demand of approximately 5,028 megawatts ("MW") and its gas distribution system met a peak day demand of 1,210 terajoules ("TJ"). For additional information on the Corporation's business segments, refer to Note 1 to the Corporation's interim unaudited consolidated financial statements for the three and six months ended June 30, 2011 and to the "Corporate Overview" section of the MD&A for the year ended December 31, 2010.

The key goals of the Corporation's regulated utilities are to operate sound gas and electricity distribution systems, deliver gas and electricity safely and reliably at the lowest reasonable cost and conduct business in an environmentally responsible manner. The Corporation's main business, utility operations, is highly regulated and the earnings of the Corporation's regulated utilities are primarily determined under cost of service ("COS") regulation.

Generally under COS regulation, the respective regulatory authority sets customer gas and electricity rates to permit a reasonable opportunity for the utility to recover, on a timely basis, estimated costs of providing service to customers, including a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). Generally, the ability of a regulated utility to recover prudently incurred costs of providing service and to earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") depends on the utility achieving the forecasts established in the rate-setting processes. As such, earnings of regulated utilities are generally impacted by: (i) changes in the regulator-approved allowed ROE or ROA; (ii) changes in rate base; (iii) changes in energy sales or gas delivery volumes; (iv) changes in the number and composition of customers; (v) variances between actual expenses incurred and forecast expenses used to determine revenue requirements and set customer rates; and (vi) timing differences, within an annual financial reporting period, between when actual expenses are incurred and when they are recovered from customers in rates. When forward test years are used to establish revenue requirements and set base customer rates, these rates are not adjusted as a result of actual COS being different from that which is estimated, other than for certain prescribed costs that are eligible for deferral account treatment. In addition, the Corporation's regulated utilities, where applicable, are permitted by their respective regulatory authority to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms.

Effective March 1, 2011, the Terasen Gas companies were renamed to operate under a common brand identity with FortisBC in British Columbia, Canada. As a result, Terasen Gas Inc. is now FortisBC Energy Inc. ("FEI"), Terasen Gas (Vancouver Island) Inc. is now FortisBC Energy (Vancouver Island) Inc. ("FEVI") and Terasen Gas (Whistler) Inc. is now FortisBC Energy (Whistler) Inc. ("FEWI"), and collectively are referred to as the FortisBC Energy companies.

On June 20, 2011, the Government of Belize ("GOB") convened special sittings of legislature to enact legislation leading to the expropriation of the Corporation's investment in Belize Electricity. As a result of no longer controlling the operations of the utility, the Corporation has discontinued the consolidation method of accounting for the financial results of Belize Electricity, effective June 20, 2011. As at June 30, 2011, the book value of the Corporation's previous investment in Belize Electricity was $112 million which has been classified in other long-term assets on the consolidated balance sheet of Fortis.

In June 2008 the Public Utilities Commission of Belize ("PUC") issued a rate order that had a significant negative impact on the financial condition and operations of Belize Electricity. The order effectively disallowed the recovery of $18 million of previously incurred fuel and purchased power costs in customer rates, $13 million of which was the Corporation's share, and set customer rates at a level that does not allow Belize Electricity to finance its operations and earn a fair and reasonable return. Since 2008, Belize Electricity has been in default of covenants under its long-term lending agreements, has had no access to credit and has not paid any dividends on common shares. Belize Electricity appealed the PUC rate order to the Supreme Court of Belize. On March 15, 2011, the Court rendered its judgment dismissing Belize Electricity's application and finding that, among other things, the generally accepted concept of good utility practice is not applicable in Belize. Belize Electricity has appealed this judgment to the Court of Appeal of Belize; however, as a result of the GOB's actions, it is unlikely that the appeal will be prosecuted by government-controlled Belize Electricity.

Fortis has initiated proceedings for compensation from the GOB for the value of the Corporation's previous investment in Belize Electricity.

The GOB has indicated publicly that it does not intend to expropriate Belize Electric Company Limited ("BECOL"), the Corporation's indirect wholly owned non-regulated subsidiary in Belize. BECOL generates hydroelectricity from three plants located on the Macal River with a combined generating capacity of 51 MW. The entire output of the plants is sold to Belize Electricity under 50-year contracts expiring in 2055 and 2060. Belize Electricity is currently purchasing energy from BECOL at approximately US$11 cents per kilowatt hour, which is one of the lowest-cost energy supply sources in the country of Belize. Fortis continues to control and consolidate the financial results of BECOL. As at June 30, 2011, the book value of the Corporation's investment in BECOL was $150 million.

As at July 31, 2011, Belize Electricity owed BECOL US$6.5 million for overdue energy purchases. The last payment received by BECOL for overdue energy purchases totaled US$0.5 million and was received on July 11, 2011. In accordance with long-standing agreements, the GOB guarantees the payment of Belize Electricity's obligations to BECOL.

FINANCIAL HIGHLIGHTS

Fortis has adopted a strategy of profitable growth with earnings per common share as the primary measure of performance. The Corporation's business is segmented by franchise area and, depending on regulatory requirements, by the nature of the assets. Key financial highlights for the second quarter and year-to-date periods ended June 30, 2011 and June 30, 2010 are provided in the following table.

Consolidated Financial Highlights (Unaudited)						
Periods Ended June 30	**Quarter**			**Year-to-Date**		
($ millions, except for share data)	**2011**	2010	Variance	**2011**	2010	Variance
Revenue	**850**	835	15	**2,014**	1,908	106
Energy Supply Costs	**358**	367	(9)	**961**	919	42
Operating Expenses	**213**	202	11	**425**	404	21
Amortization	**103**	97	6	**206**	191	15
Finance Charges	**92**	88	4	**183**	178	5
Corporate Taxes	**15**	15	-	**45**	43	2
Net Earnings	**69**	66	3	**194**	173	21
Net Earnings Attributable to:						
Non-Controlling Interests	**3**	3	-	**4**	4	-
Preference Equity Shareholders	**8**	8	-	**15**	14	1
Common Equity Shareholders	**58**	55	3	**175**	155	20
	69	66	3	**194**	173	21
Basic Earnings per Common Share *($)*	**0.33**	0.32	0.01	**1.00**	0.90	0.10
Diluted Earnings per Common Share *($)*	**0.33**	0.32	0.01	**0.99**	0.88	0.11
Weighted Average Number of Common Shares Outstanding *(millions)*	**177.1**	172.4	4.7	**175.8**	172.0	3.8
Cash Flow from Operating Activities	**228**	204	24	**527**	405	122

Factors Contributing to Quarterly Revenue Variance

Favourable

- Gas and energy sales growth, mainly due to weather-related increases in consumption, and growth in the number of customers at FortisAlberta
- The timing of recording of the cumulative impact of FortisAlberta's 2010 revenue requirements decision. The impact of the rate decision was recorded during the third quarter of 2010 when the decision was received.
- An increase in gas delivery rates and the base component of electricity rates at several of the utilities, consistent with rate case decisions, reflecting ongoing investment in utility infrastructure and higher regulator-approved expenses recoverable from customers
- The flow through in customer electricity rates of overall higher energy supply costs driven by Caribbean Utilities and Maritime Electric
- The recognition of $2.5 million of accrued revenue at FortisAlberta during the second quarter of 2011 related primarily to the cumulative 2010 and year-to-date 2011 return and amortization on the additional $22 million in capital expenditures associated with the Automated Metering Project, as approved by the regulator to be included in rate base

Unfavourable

- Lower commodity cost of natural gas charged to customers
- The discontinuance of the consolidation method of accounting for the financial results of Belize Electricity, effective June 20, 2011
- Increased performance-based rate-setting ("PBR") incentive adjustments owing to customers by FortisBC Electric
- Approximately $6 million unfavourable foreign exchange associated with the translation of foreign currency-denominated revenue, due to the weakening of the US dollar relative to the Canadian dollar

Factors Contributing to Year-to-Date Revenue Variance

Favourable

- Gas and energy sales growth for the same reasons as discussed above for the quarter
- The timing of recording of the cumulative impacts of FortisAlberta's and FEWI's 2010 revenue requirements decisions. The impacts of the rate decisions were recorded during the third quarter of 2010 when the decisions were received.
- The increase in gas delivery rates and the base component of electricity rates, as discussed above for the quarter
- The flow through in customer electricity rates of overall higher energy supply costs
- The $2.5 million of accrued revenue associated with the cumulative return and amortization on the additional capital expenditures included in rate base associated with the Automated Metering Project, as discussed above for the quarter
- An approximate $1 million gain on sale of property during the first quarter of 2011

Unfavourable

- Lower commodity cost of natural gas charged to customers
- Increased PBR incentive adjustments, as discussed above for the quarter
- Decreased amortization of regulatory liabilities and deferrals at Newfoundland Power, as approved by the regulator
- Approximately $10 million associated with unfavourable foreign currency translation

Factors Contributing to Quarterly Energy Supply Costs Variance

Favourable

- Lower commodity cost of natural gas
- Lower average market-priced purchased power costs at FortisBC Electric and FortisOntario
- Approximately $3 million associated with favourable foreign currency translation
- The discontinuance of the consolidation method of accounting for the financial results of Belize Electricity, effective June 20, 2011

Unfavourable

- Gas and energy sales growth
- Higher energy supply costs associated with increased fuel costs at Caribbean Utilities and an increase in the recovery of energy supply costs at Maritime Electric through the operation of the Energy Cost Adjustment Mechanism

Factors Contributing to Year-to-Date Energy Supply Costs Variance

Unfavourable

- The same factors as discussed above for the quarter

Favourable

- Lower commodity cost of natural gas
- Lower average market-priced purchased power costs at FortisBC Electric and FortisOntario
- Approximately $6 million associated with favourable foreign currency translation

Factors Contributing to Quarterly and Year-to-Date Operating Expenses Variances

Unfavourable

- Higher operating expenses at Newfoundland Power, mainly due to the regulator-approved change in the accounting treatment for other post-employment benefit ("OPEB") costs, and the timing of labour costs
- Wage and general inflationary increases
- The timing of and regulator-approved increase in certain operating expenses at the FortisBC Energy companies

Favourable
- Higher corporate operating expenses incurred in the first half of 2010 related to business development costs

Factors Contributing to Quarterly and Year-to-Date Amortization Costs Variances

Unfavourable
- Higher amortization rates at FortisAlberta, due to the timing of recording of the cumulative impact of FortisAlberta's 2010 revenue requirements decision. The impact of the rate decision was recorded during the third quarter of 2010 when the decision was received.
- Continued investment in utility infrastructure and income producing properties

Favourable
- Reduced amortization costs at the FortisBC Energy companies, mainly due to the retirement late in 2010 of certain general plant assets and the amortization in 2011 of a regulatory deferral account
- Increased amortization costs during the first half of 2010 at Newfoundland Power, due to approximate $1 million and $2 million adjustments for the second quarter and year-to-date periods of 2010, respectively, as approved by the regulator, related to an amortization study

Factors Contributing to Quarterly and Year-to-Date Finance Charges Variances

Unfavourable
- Higher debt levels in support of the utilities' capital expenditure programs

Favourable
- The refinancing of maturing corporate debt at a lower rate in April 2010
- Higher capitalized allowance for funds used during construction year to date

Factors Contributing to Quarterly and Year-to-Date Corporate Taxes Variances

Favourable
- Lower effective corporate income tax rate, driven by higher deductions for income tax purposes compared to accounting purposes and lower statutory income tax rates

Unfavourable
- Higher earnings before corporate taxes

Factors Contributing to Quarterly and Year-to-Date Earnings Variances

Favourable
- An approximate $6 million and $10.5 million earnings impact for the quarter and year to date, respectively, related to rate base growth, mainly at the regulated utilities in western Canada, due to continued investment in utility infrastructure
- The $2.5 million of accrued revenue associated with the cumulative return and amortization on the additional capital expenditures included in rate base associated with the Automated Metering Project, as discussed above
- The favourable impact year to date of the timing of recording of the cumulative impacts of FortisAlberta's and FEWI's 2010 revenue requirements decisions. The impacts of the rate decisions were recorded during the third quarter of 2010 when the decisions were received.
- Lower average market-priced purchased power costs at FortisBC Electric
- The favourable impact year to date of higher energy sales driven by FortisBC Electric and FortisAlberta
- Higher corporate operating expenses incurred in the first half of 2010 related to business development costs
- Higher capitalized allowance for funds used during construction year to date related to the construction of the liquefied natural gas ("LNG") storage facility on Vancouver Island
- A higher allowed ROE at Algoma Power

Unfavourable

- The timing of and regulator-approved increase in certain operating expenses at the FortisBC Energy companies
- Decreased earnings from non-regulated hydroelectric generation operations for the quarter reflecting decreased production at BECOL due to lower rainfall
- Lower earnings from Fortis Properties reflecting lower occupancies at hotel operations in western Canada, combined with increased operating expenses

SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders (Unaudited)						
Periods Ended June 30	**Quarter**			**Year-to-Date**		
($ millions)	**2011**	2010	Variance	**2011**	2010	Variance
Regulated Gas Utilities - Canadian						
FortisBC Energy Companies	**15**	17	(2)	**91**	90	1
Regulated Electric Utilities - Canadian						
FortisAlberta	***19***	*17*	*2*	***40***	*32*	*8*
FortisBC Electric	***9***	*8*	*1*	***28***	*22*	*6*
Newfoundland Power	***11***	*11*	*-*	***18***	*18*	*-*
Other Canadian Electric Utilities	***6***	*4*	*2*	***12***	*9*	*3*
	45	40	5	**98**	81	17
Regulated Electric Utilities - Caribbean	**7**	7	-	**10**	11	(1)
Non-Regulated - Fortis Generation	**2**	3	(1)	**5**	5	-
Non-Regulated - Fortis Properties	**7**	8	(1)	**9**	10	(1)
Corporate and Other	**(18)**	(20)	2	**(38)**	(42)	4
Net Earnings Attributable to Common Equity Shareholders	**58**	55	3	**175**	155	20

For a discussion of the nature of regulation and material regulatory decisions and applications pertaining to the Corporation's regulated utilities, refer to the "Regulatory Highlights" section of this MD&A. A discussion of the financial results of the Corporation's reporting segments is as follows.

REGULATED GAS UTILITIES - CANADIAN

FORTISBC ENERGY COMPANIES [(1)]

Gas Volumes by Major Customer Category (Unaudited)						
Periods Ended June 30	**Quarter**			**Year-to-Date**		
(TJ)	**2011**	2010	Variance	**2011**	2010	Variance
Core – Residential and Commercial	**24,951**	23,827	1,124	**75,399**	64,258	11,141
Industrial	**1,229**	1,193	36	**3,117**	2,868	249
Total Sales Volumes	**26,180**	25,020	1,160	**78,516**	67,126	11,390
Transportation Volumes	**16,730**	14,090	2,640	**37,214**	30,500	6,714
Throughput under Fixed Revenue Contracts	**489**	2,374	(1,885)	**965**	6,766	(5,801)
Total Gas Volumes	**43,399**	41,484	1,915	**116,695**	104,392	12,303

[(1)] The FortisBC Energy companies are comprised of FEI, FEVI and FEWI.

Factors Contributing to Quarterly and Year-to-Date Gas Volumes Variances

Favourable
- Higher average consumption by residential and commercial customers as a result of cooler weather
- Higher transportation volumes reflecting improving economic conditions favourably affecting the forestry sector

Unfavourable
- Lower volumes under fixed revenue contracts, mainly due to higher precipitation, which made it more cost efficient for a large customer to not utilize its natural gas-powered generating facility during the first half of 2011

Net customer additions were 1,002 during the first half of 2011 compared to 1,829 during the first half of 2010. Gross customer additions decreased due to lower building activity during 2011.

Seasonality has a material impact on the earnings of the FortisBC Energy companies as a major portion of the gas distributed is used for space heating. Most of the annual earnings of the FortisBC Energy companies are realized in the first and fourth quarters.

The FortisBC Energy companies earn approximately the same margin regardless of whether a customer contracts for the purchase and delivery of natural gas or for the transportation only of natural gas. As a result of the operation of regulator-approved deferral mechanisms, changes in consumption levels and energy supply costs from those forecast to set residential and commercial customer gas rates do not materially affect earnings.

Financial Highlights (Unaudited)						
Periods Ended June 30	**Quarter**			**Year-to-Date**		
($ millions)	**2011**	2010	Variance	**2011**	2010	Variance
Revenue	**320**	336	(16)	**895**	862	33
Earnings	**15**	17	(2)	**91**	90	1

Factors Contributing to Quarterly Revenue Variance

Unfavourable
- Lower commodity cost of natural gas charged to customers

Favourable
- Higher average gas consumption by residential and commercial customers
- Higher transportation volumes in the forestry sector
- An increase in the delivery component of customer rates, mainly due to ongoing investment in utility infrastructure and higher regulator-approved operating expenses recoverable from customers

Factors Contributing to Year-to-Date Revenue Variance

Favourable
- The same factors as discussed above for the quarter
- The timing of recording of the cumulative impact of FEWI's 2010 revenue requirements decision. The impact of the rate decision was recorded during the third quarter of 2010.

Unfavourable
- The same factor as discussed above for the quarter

Factors Contributing to Quarterly Earnings Variance

Unfavourable
- The timing of and regulator-approved increase in operating expenses, driven by labour and benefits costs and consulting expenses

Favourable
- Rate base growth, due to continued investment in utility infrastructure

- Reduced amortization costs, mainly due to the retirement late in 2010 of certain general plant assets
- Higher transportation volumes in the forestry sector

Factors Contributing to Year-to-Date Earnings Variance

Favourable

- The same factors as discussed above for the quarter
- The timing of recording of the cumulative impact of FEWI's revenue requirements decision, as discussed above
- Higher capitalized allowance for funds used during construction related to the construction of the LNG storage facility

Unfavourable

- The same factor as discussed above for the quarter

REGULATED ELECTRIC UTILITIES - CANADIAN

FORTISALBERTA

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended June 30	**2011**	2010	Variance	**2011**	2010	Variance
Energy Deliveries *(gigawatt hours ("GWh"))*	**3,822**	3,784	38	**8,224**	7,833	391
Revenue *($ millions)*	**104**	92	12	**207**	180	27
Earnings *($ millions)*	**19**	17	2	**40**	32	8

Factors Contributing to Quarterly Energy Deliveries Variance

Favourable

- Lower average consumption during the second quarter of 2010 by residential, commercial and oilfield customers
- Customer growth, with the total number of customers increasing by approximately 9,400 quarter over quarter

Unfavourable

- Decreased energy deliveries to farm and irrigation customers, due to differences in rainfall period over period
- Lower energy deliveries to other industrial customers

Factors Contributing to Year-to-Date Energy Deliveries Variance

Favourable

- Increased average consumption by residential and commercial customers due to temperature differences period over period
- Increased activity in the oil and gas sector
- Growth in the number of customers, as discussed above for the quarter

As a significant portion of FortisAlberta's distribution revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

Factors Contributing to Quarterly and Year-to-Date Revenue Variances

Favourable

- The recognition of $2.5 million of accrued revenue during the second quarter of 2011 related primarily to the cumulative 2010 and year-to-date 2011 return and amortization on the additional $22 million in capital expenditures associated with the Automated Metering Project, as approved by the regulator to be included in rate base. For further information, refer to the "Material Regulatory Decisions and Applications – FortisAlberta" section of this MD&A.

- A 4.7% increase in base customer electricity distribution rates over final-approved 2010 rates, effective January 1, 2011, associated with the 2010-2011 regulatory rate decision. The increase in base rates was primarily due to ongoing investment in utility infrastructure.
- Revenue for the first half of 2010 reflected a 7.5% interim customer rate increase, whereas revenue for the first half of 2011 reflected the full impact of approved rate increases as provided in the 2010-2011 regulatory rate decision. The cumulative impact from January 1, 2010 of the rate decision was recorded during the third quarter of 2010 when the decision was received. The final-approved customer rate increase for 2010 was 20.1% related to the distribution component of customer rates.
- Growth in the number of customers

Unfavourable
- Lower net transmission revenue. Effective January 1, 2010, as a result of the 2010-2011 regulatory rate decision that was received, and the effects of which were recorded during the third quarter of 2010, all transmission costs and revenue are deferred to be recovered from, or refunded to, customers in future rates.
- Lower miscellaneous revenue for the quarter

Factors Contributing to Quarterly Earnings Variance

Favourable
- The $2.5 million of accrued revenue associated with the cumulative return and amortization on the additional capital expenditures included in rate base associated with the Automated Metering Project, as discussed above
- Rate base growth, due to continued investment in utility infrastructure

Unfavourable
- Lower net transmission revenue
- Lower-than-expected customer growth and energy deliveries to farm and irrigation customers

Factors Contributing to Year-to-Date Earnings Variance

Favourable
- The same factors as discussed above for the quarter
- The timing of recording of the cumulative impact of FortisAlberta's 2010-2011 regulatory rate decision. The impact of the decision was recorded in the third quarter of 2010 when the decision was received.
- Higher energy deliveries to residential and commercial customers

Unfavourable
- Lower net transmission revenue

FORTISBC ELECTRIC [(1)]

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended June 30	**2011**	2010	Variance	**2011**	2010	Variance
Electricity Sales *(GWh)*	**682**	671	11	**1,587**	1,491	96
Revenue *($ millions)*	**64**	59	5	**148**	131	17
Earnings *($ millions)*	**9**	8	1	**28**	22	6

(1) Formerly referred to as FortisBC, and includes the regulated operations of FortisBC Inc. and operating, maintenance and management services related to the Waneta, Brilliant and Arrow Lakes hydroelectric generating plants and the distribution system owned by the City of Kelowna. Excludes the non-regulated generation operations of FortisBC Inc.'s wholly owned partnership, Walden Power Partnership.

Factors Contributing to Quarterly and Year-to-Date
Electricity Sales Variances

Favourable
- Growth in the number of customers
- Lower average consumption during the first quarter of 2010 due to warmer-than-normal temperatures experienced during that period

Factors Contributing to Quarterly and Year-to-Date Revenue Variances

Favourable

- A 6.6% increase in customer electricity rates, effective January 1, 2011, mainly reflecting ongoing investment in utility infrastructure and the higher cost of capital
- A refundable interim 1.4% and a 2.9% increase in customer electricity rates, effective June 1, 2011 and September 1, 2010, respectively, as a result of the flow through to customers of increased purchased power costs charged to FortisBC Electric by BC Hydro
- The 1.6% and 6.4% increase in electricity sales for the quarter and year to date, respectively
- Higher revenue contribution from non-regulated operating, maintenance and management services

Unfavourable

- Increased PBR incentive adjustments owing to customers
- Lower pole attachment revenue, partially offset by higher wheeling revenue

Factors Contributing to Quarterly and Year-to-Date Earnings Variances

Favourable

- Rate base growth, due to continued investment in utility infrastructure
- Lower-than-expected average consumption in the first quarter of 2010 for the reason discussed above
- Lower-than-expected average market-priced purchased power costs

Unfavourable

- Higher-than-expected PBR-incentive adjustments owing to customers, driven by the lower-than-expected average market-priced purchased power costs

NEWFOUNDLAND POWER

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended June 30	**2011**	2010	Variance	**2011**	2010	Variance
Electricity Sales *(GWh)*	**1,269**	1,220	49	**3,103**	3,015	88
Revenue *($ millions)*	**133**	126	7	**316**	304	12
Earnings *($ millions)*	**11**	11	-	**18**	18	-

Factors Contributing to Quarterly and Year-to-Date Electricity Sales Variances

Favourable

- Growth in the number of customers
- Higher average consumption reflecting higher concentration of electric heating in new homes combined with strong economic growth

Factors Contributing to Quarterly and Year-to-Date Revenue Variances

Favourable

- The 4.0% and 2.9% increase in electricity sales for the quarter and year to date, respectively
- An overall average 0.8% increase in customer electricity rates, effective January 1, 2011, mainly reflecting higher OPEB costs, partially offset by a decrease in the allowed ROE to 8.38% for 2011, down from 9.00% for 2010

Unfavourable

- Decreased amortization of regulatory liabilities and deferrals as approved by the regulator

Factors Contributing to Quarterly and Year-to-Date Earnings Variances

Unfavourable

- The decrease in the allowed ROE, as reflected in customer rates
- Wage and inflationary increases
- Timing of labour costs as a result of higher capital work performed in the first half of 2010, due to an early start of the capital program and restoration work related to an ice storm in March 2010, as well as a significant portion of certain employee initiatives were completed during the first half of 2011

Favourable

- Electricity sales growth
- Lower effective corporate income taxes in 2011, primarily due to a lower statutory income tax rate

OTHER CANADIAN ELECTRIC UTILITIES [(1)]

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended June 30	**2011**	2010	Variance	**2011**	2010	Variance
Electricity Sales *(GWh)*	**562**	535	27	**1,216**	1,167	49
Revenue *($ millions)*	**78**	75	3	**169**	157	12
Earnings *($ millions)*	**6**	4	2	**12**	9	3

[(1)] Includes Maritime Electric and FortisOntario. FortisOntario mainly includes Canadian Niagara Power, Cornwall Electric and Algoma Power.

Factors Contributing to Quarterly and Year-to-Date Electricity Sales Variances

Favourable

- Higher average consumption, reflecting colder temperatures in Ontario and Prince Edward Island ("PEI")

Factors Contributing to Quarterly and Year-to-Date Revenue Variances

Favourable

- The 5.0% and 4.2% increase in electricity sales for the quarter and year to date, respectively
- An increase in the basic component of customer rates at Maritime Electric associated with the recovery of energy supply costs
- An average 3.8% increase in customer electricity rates at Algoma Power, effective December 1, 2010, reflecting an increase in the allowed ROE to 9.85% for 2011 from 8.57% for 2010 and the use of a forward test year for rate setting

Unfavourable

- The flow through in customer electricity rates of lower energy supply costs at FortisOntario
- The flow through to customers of lower power purchase costs charged by New Brunswick Power ("NB Power") as a result of a new five-year power purchase agreement between Maritime Electric and NB Power

Factors Contributing to Quarterly and Year-to-Date Earnings Variances

Favourable

- A higher allowed ROE at Algoma Power, as reflected in customer rates
- Electricity sales growth
- A deferred start to the vegetation management program in Ontario during 2011
- Lower effective corporate income taxes at FortisOntario in 2011, primarily due to higher deductions taken for income tax purposes compared to accounting purposes during the second quarter of 2011

REGULATED ELECTRIC UTILITIES - CARIBBEAN [(1)]

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended June 30	**2011**	2010	Variance	**2011**	2010	Variance
Average US:CDN Exchange Rate [(2)]	**0.97**	1.03	(0.06)	**0.98**	1.03	(0.05)
Electricity Sales *(GWh)*	**290**	307	(17)	**547**	562	(15)
Revenue *($ millions)*	**87**	83	4	**162**	159	3
Earnings *($ millions)*	**7**	7	-	**10**	11	(1)

(1) Includes Caribbean Utilities on Grand Cayman, Cayman Islands, in which Fortis holds an approximate 59% controlling interest; wholly owned Fortis Turks and Caicos; and the financial results of the Corporation's approximate 70% controlling interest in Belize Electricity up to June 20, 2011. Effective June 20, 2011, the GOB enacted legislation leading to the expropriation of the Corporation's investment in Belize Electricity. As a result of no longer controlling the operations of the utility, Fortis discontinued the consolidation method of accounting for the financial results of Belize Electricity, effective June 20, 2011. For further information, refer to the "Corporate Overview" section of this MD&A.

(2) The reporting currency of Caribbean Utilities and Fortis Turks and Caicos is the US dollar. The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the US dollar at BZ$2.00=US$1.00.

Factors Contributing to Quarterly and Year-to-Date Electricity Sales Variances

Unfavourable

- The impact of the discontinuance of the consolidation method of accounting for the financial results of Belize Electricity, effective June 20, 2011. For further information, refer to the "Corporate Overview" section of this MD&A.
- The loss at Belize Electricity of a large industrial customer that began generating its own electricity during the fourth quarter of 2010
- Tempered energy consumption due to persistent challenging economic conditions in the region combined with a declining population on Grand Cayman
- Cooler weather conditions experienced on Grand Cayman during the second quarter of 2011, which decreased air conditioning load, partially offset by warmer and drier weather conditions experienced during the first quarter of 2011

Favourable

- Growth in the number of customers in Grand Cayman and the Turks and Caicos Islands

Factors Contributing to Quarterly and Year-to-Date Revenue Variances

Favourable

- The flow through in customer electricity rates of higher energy supply costs at Caribbean Utilities, due to an increase in the cost of fuel
- A commercial customer billing adjustment at Caribbean Utilities

Unfavourable

- The discontinuance of the consolidation method of accounting for the financial results of Belize Electricity, effective June 20, 2011
- Approximately $5 million and $10 million unfavourable foreign exchange for the quarter and year to date, respectively, associated with the translation of foreign currency-denominated revenue, due to the weakening of the US dollar relative to the Canadian dollar
- Lower electricity sales on Grand Cayman

Factors Contributing to Quarterly and Year-to-Date Earnings Variances

Unfavourable

- Lower electricity sales on Grand Cayman
- The discontinuance of the consolidation method of accounting for the financial results of Belize Electricity, effective June 20, 2011
- Higher finance charges at Belize Electricity due to interest expense on regulatory liabilities

Favourable

- Ongoing efforts of reducing costs and improving efficiencies to temper the impact of persistent challenging economic conditions in the region
- Lower corporate taxes at Belize Electricity. Corporate taxes in the second quarter of 2010 reflected an increase in the business tax rate to 6.5% from 1.75%, effective April 1, 2010. During the third quarter of 2010, the previously expensed increase in business taxes was reversed and deferred for future collection from customers.
- A commercial customer billing adjustment at Caribbean Utilities

NON-REGULATED - FORTIS GENERATION [(1)]

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended June 30	**2011**	2010	Variance	**2011**	2010	Variance
Energy Sales *(GWh)*	**90**	87	3	**166**	156	10
Revenue *($ millions)*	**7**	8	(1)	**14**	13	1
Earnings *($ millions)*	**2**	3	(1)	**5**	5	-

[(1)] Includes the financial results of non-regulated generation assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State, with a combined generating capacity of 139 megawatts, mainly hydroelectric. Results reflect contribution from the Vaca hydroelectric generating facility in Belize from late March 2010 when the facility was commissioned.

Factors Contributing to Quarterly and Year-to-Date Energy Sales Variances

Favourable

- Increased production in Upper New York State and Ontario, due to higher rainfall

Unfavourable

- Decreased production in Belize due to lower rainfall

Factors Contributing to Quarterly and Year-to-Date Revenue Variances

Unfavourable

- Decreased production in Belize

Favourable

- Increased production and higher average energy sales rate per megawatt hour ("MWh") in Ontario. The average rate per MWh for the second quarter of 2011 was $72.09 compared to $50.72 for the same quarter in 2010. The average rate per MWh for the first half of 2011 was $72.34 compared to $38.40 for the first half of 2010. Effective May 1, 2010, energy produced in Ontario is being sold under a fixed-price contract with price indexing. Previously, energy was sold at market rates.
- Increased production in Upper New York State

Factors Contributing to Quarterly and Year-to-Date Earnings Variances

Unfavourable

- Decreased production in Belize
- Higher finance charges as a result of lower interest revenue associated with lower inter-company lending to regulated operations in Ontario

Favourable

- Increased production and higher average energy sales rates in Ontario
- Increased production in Upper New York State

NON-REGULATED - FORTIS PROPERTIES [1]

Financial Highlights (Unaudited) Periods Ended June 30 ($ millions)	Quarter 2011	2010	Variance	Year-to-Date 2011	2010	Variance
Hospitality Revenue	**43**	43	-	**76**	76	-
Real Estate Revenue	**17**	17	-	**34**	33	1
Total Revenue	**60**	60	-	**110**	109	1
Earnings	**7**	8	(1)	**9**	10	(1)

[1] Fortis Properties owns and operates 21 hotels, comprised of more than 4,100 rooms, in eight Canadian provinces and approximately 2.7 million square feet of commercial office and retail space primarily in Atlantic Canada.

Factors Contributing to Quarterly Revenue Variance

Favourable

- Rent increases at the Real Estate Division

Unfavourable

- A 0.2% decrease in revenue per available room ("RevPar") at the Hospitality Division to $83.57 for the second quarter of 2011 from $83.77 for the same quarter in 2010. RevPar decreased due to an overall 2.2% decrease in hotel occupancy, most significantly in western Canada, partially offset by an overall 2.0% increase in the average daily room rate. The average daily room rate increased in all regions.
- A decrease in the occupancy rate at the Real Estate Division to 93.4% as at June 30, 2011 from 94.8% as at June 30, 2010, mainly associated with increased vacancy at operations in Newfoundland and New Brunswick

Factors Contributing to Year-to-Date Revenue Variance

Favourable

- A $0.5 million gain on the sale of the Viking Mall in rural Newfoundland during the first quarter of 2011
- Rent increases at the Real Estate Division

Unfavourable

- The decrease in the occupancy rate at the Real Estate Division, as discussed above for the quarter
- A 0.1% decrease in RevPar at the Hospitality Division to $73.41 for the first half of 2011 from $73.45 for the first half of 2010. RevPar decreased due to an overall 1.8% decrease in hotel occupancy, partially offset by an overall 1.7% increase in the average daily room rate. Hotel occupancy at operations in western Canada decreased, while occupancy at operations in central Canada increased. The average daily room rate increased in all regions.

Factors Contributing to Quarterly and Year-to-Date Earnings Variances

Unfavourable

- Lower performance of hotel operations, driven by the continued unfavourable impact of decreased occupancies at hotel operations in western Canada
- Higher operating expenses due to inflationary pressures
- Higher amortization costs year to date due to capital investment in both the Hospitality and Real Estate Divisions

Favourable

- The $0.5 million gain on the sale of the Viking Mall

CORPORATE AND OTHER [1]

Financial Highlights (Unaudited)						
Periods Ended June 30	Quarter			Year-to-Date		
($ millions)	**2011**	2010	Variance	**2011**	2010	Variance
Revenue	**8**	9	(1)	**15**	15	-
Operating Expenses	**3**	6	(3)	**4**	10	(6)
Amortization	**1**	1	-	**3**	4	(1)
Finance Charges [2]	**18**	18	-	**37**	38	(1)
Corporate Tax Recovery	**(4)**	(4)	-	**(6)**	(9)	3
	(10)	(12)	2	**(23)**	(28)	5
Preference Share Dividends	**8**	8	-	**15**	14	1
Net Corporate and Other Expenses	**(18)**	(20)	2	**(38)**	(42)	4

[1] Includes Fortis net corporate expenses, net expenses of non-regulated FortisBC Holdings Inc. ("FHI") (formerly Terasen Inc.) corporate-related activities and the financial results of FHI's 30% ownership interest in CustomerWorks Limited Partnership and of FHI's non-regulated wholly owned subsidiary FortisBC Alternative Energy Services Inc. (formerly Terasen Energy Services Inc.)

[2] Includes dividends on preference shares classified as long-term liabilities

Factors Contributing to Quarterly and Year-to-Date Net Corporate and Other Expenses Variances

Favourable

- Reduced operating expenses. Operating expenses were higher during the first half of 2010 due to business development costs incurred during that period.
- Lower finance charges year to date, driven by the redemption of $125 million 8.0% Capital Securities in April 2010 and the favourable foreign exchange impact associated with the translation of US dollar-denominated interest expense, partially offset by the impact of higher average credit facility borrowings combined with higher interest rates charged on those credit facility borrowings

Unfavourable

- Lower corporate tax recovery year to date, mainly due to a lower net loss for income tax purposes
- Higher preference share dividends year to date, due to the issuance of First Preference Shares, Series H in January 2010

REGULATORY HIGHLIGHTS

The nature of regulation and material regulatory decisions and applications associated with each of the Corporation's regulated gas and electric utilities for the first half of 2011 are summarized as follows:

NATURE OF REGULATION

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%) 2009	2010	2011	Supportive Features Future or Historical Test Year Used to Set Customer Rates
				ROE		COS/ROE
FEI	British Columbia Utilities Commission ("BCUC")	40 (1)	8.47 (2) /9.50 (3)	9.50	9.50	FEI: Prior to January 1, 2010, 50/50 sharing of earnings above or below the allowed ROE under a PBR mechanism that expired on December 31, 2009 with a two-year phase-out
FEVI	BCUC	40	9.17 (2) /10.00 (3)	10.00	10.00	
FEWI	BCUC	40	8.97 (2) /10.00 (3)	10.00	10.00	ROEs established by the BCUC, effective July 1, 2009, as a result of a cost of capital decision in the fourth quarter of 2009. Previously, the allowed ROEs were set using an automatic adjustment formula tied to long-term Canada bond yields.
						Future Test Year
FortisBC Electric	BCUC	40	8.87	9.90	9.90	COS/ROE PBR mechanism for 2009 through 2011: 50/50 sharing of earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE – excess to deferral account ROE established by the BCUC, effective January 1, 2010, as a result of a cost of capital decision in the fourth quarter of 2009. Previously, the allowed ROE was set using an automatic adjustment formula tied to long-term Canada bond yields.
						Future Test Year
FortisAlberta	Alberta Utilities Commission ("AUC")	41	9.00	9.00	9.00 (4)	COS/ROE ROE established by the AUC, effective January 1, 2009, as a result of a generic cost of capital decision in the fourth quarter of 2009. Previously, the allowed ROE was set using an automatic adjustment formula tied to long-term Canada bond yields.
						Future Test Year
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB")	45	8.95 +/- 50 bps	9.00 +/- 50 bps	8.38 +/- 50 bps	COS/ROE ROE for 2010 established by the PUB. Except for 2010, the allowed ROE is set using an automatic adjustment formula tied to long-term Canada bond yields.
						Future Test Year
Maritime Electric	Island Regulatory and Appeals Commission ("IRAC")	40	9.75	9.75	9.75	COS/ROE Future Test Year

NATURE OF REGULATION (cont'd)

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%) 2009	2010	2011	Supportive Features Future or Historical Test Year Used to Set Customer Rates
				ROE		
FortisOntario	Ontario Energy Board ("OEB")					Canadian Niagara Power - COS/ROE
	Canadian Niagara Power	40 [5]	8.01	8.01	8.01	Algoma Power – COS/ROE and subject to Rural and Remote Rate Protection ("RRRP") Program
	Algoma Power	50 [6] /40 [7]	8.57	8.57	9.85 [7]	
	Franchise Agreement Cornwall Electric					Cornwall Electric – Price cap with commodity cost flow through
						Canadian Niagara Power – 2009 test year for 2009, 2010 and 2011 Algoma Power – 2007 historical test year for 2009 and 2010; 2011 test year for 2011
				ROA		
Caribbean Utilities	Electricity Regulatory Authority ("ERA")	N/A	9.00 - 11.00	7.75 - 9.75	7.75 - 9.75	COS/ROA Rate-cap adjustment mechanism ("RCAM") based on published consumer price indices The Company may apply for a special additional rate to customers in the event of a disaster, including a hurricane.
						Historical Test Year
Fortis Turks and Calcos	Utilities make annual filings to the Governor	N/A	17.50 [8]	17.50 [8]	17.50 [8]	COS/ROA If the actual ROA is lower than the allowed ROA, due to additional costs resulting from a hurricane or other event, the Company may apply for an increase in customer rates in the following year.
						Future Test Year

(1) Effective January 1, 2010. For 2009, the allowed common equity component of capital structure was 35%.
(2) Pre-July 1, 2009
(3) Effective July 1, 2009
(4) Interim pending finalization by the AUC
(5) Effective May 1, 2010. For 2009, effective May 1, the allowed common equity component of capital structure was 43.3%.
(6) Pre-December 1, 2010
(7) Effective December 1, 2010
(8) Amount provided under licence. ROA achieved in 2009 and 2010 was materially lower than the ROA allowed under the licence. Fortis Turks and Caicos requested a review of its rates in 2010.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS

Regulated Utility	Summary Description
FEI / FEVI / FEWI	• FEI and FEWI review natural gas and propane commodity and mid-stream rates with the BCUC every three months in order to ensure the flow-through rates charged to customers are sufficient to cover the cost of purchasing natural gas and propane and contracting for mid-stream resources, such as third-party pipeline and/or storage capacity. The commodity cost of natural gas and propane and mid-stream costs are flowed through to customers without markup. The delivery rate charged to FEVI customers includes a component to recover approved gas costs and is set annually. In order to ensure that the balances in the Commodity Cost Reconciliation Account and Mid-Stream Cost Reconciliation Account ("MCRA") are recovered on a timely basis, FEI and FEWI prepare and file quarterly calculations with the BCUC to determine whether customer rate adjustments are needed to reflect prevailing market prices for natural gas and propane. These rate adjustments ignore the temporal effect of derivative valuation adjustments on the balance sheet and, instead, reflect the forward forecast of gas costs over the recovery period. • Effective January 1, 2011, rates for residential customers in the Lower Mainland, Fraser Valley, Interior, North and Kootenay service areas decreased by approximately 6%, as approved by the BCUC, to reflect net changes in delivery, commodity and mid-stream costs. Natural gas commodity rates remained unchanged as of April 1, 2011 and as of July 1, 2011, following the BCUC's quarterly reviews of such rates. • In December 2010 FEI filed an application with the BCUC to provide fuelling services through FEI-owned and operated compressed natural gas and LNG fuelling stations. In July 2011 FEI received a decision from the BCUC that approved the fuelling station infrastructure along with a long-term contract with one counterparty for the supply of compressed natural gas. The BCUC denied the Company's application for a general tariff for the provision of compressed natural gas and LNG for vehicles, unless certain contractual conditions are met. The Company is considering these proposed amendments in the context of new natural gas vehicle stations. • FEI, FEVI and FEWI are expecting to file an application with the BCUC during the third quarter of 2011 for the amalgamation of the three companies. An amalgamation would require an application to be approved by the BCUC and consent of the Government of British Columbia. • In January 2011 FEI filed its review of the Price Risk Management Plan ("PRMP") objectives with the BCUC related to its gas commodity hedging plan and also submitted a 2011-2014 PRMP. In June 2011 FEVI filed a 2012-2013 hedging request application. In July 2011 the BCUC denied FEI's 2011-2014 PRMP with the exception of certain elements related to basis swaps. The existing hedging contracts are expected to continue in effect through to their maturity and the gas utilities' ability to fully recover the commodity cost of gas in customer rates remains unchanged. • In May 2011 the FortisBC Energy companies filed their 2012-2013 Revenue Requirements Applications. FEI requested a 2.8% increase in customer delivery rates effective January 1, 2012 and a 3.0% increase, effective January 1, 2013. The requested rate increases are driven by ongoing investment in utility infrastructure focused on system integrity and reliability, and forecast increased operating expenses associated with inflation, a heightened focus on safety and security of the natural gas systems and increasing compliance with codes and regulations. FEI's application assumes forecast average rate base of approximately $2,737 million for 2012 and $2,788 million for 2013. FEVI requested that customer delivery rates remain unchanged for the two-year period beginning January 1, 2012. FEVI's application assumes forecast average rate base of $788 million for 2012 and $814 million for 2013. • In July 2011 the BCUC approved the application jointly filed by the FortisBC Energy companies and FortisBC Electric requesting the utilities be permitted to adopt United States generally accepted accounting principles ("US GAAP") effective January 1, 2012 for regulatory reporting purposes. • In July 2011 FEVI received a BCUC decision approving the option for two First Nations bands to invest in up to 15% of the equity component of the capital structure of the new LNG storage facility on Vancouver Island. If the option is exercised, the equity investment by the First Nations bands would occur effective January 1, 2012.
FortisBC Electric	• In December 2010 the BCUC approved a Negotiated Settlement Agreement ("NSA") pertaining to FortisBC Electric's 2011 Revenue Requirements Application. The result was a general customer electricity rate increase of 6.6%, effective January 1, 2011. The rate increase was primarily the result of the Company's ongoing investment in utility infrastructure and the higher cost of capital.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FortisBC Electric (cont'd)	• In June 2011 FortisBC Electric filed its 2012-2013 Revenue Requirements Application and its Integrated System Plan ("ISP"). The ISP includes the Company's Resource Plan, Long-Term Capital Plan and Long-Term Demand Side Management Plan. FortisBC Electric requested an interim 4% increase in customer electricity rates effective January 1, 2012 and a 6.9% increase effective January 1, 2013. The rate increases are due to ongoing investment in utility infrastructuure, increasing costs of financing the ongoing investment, and increasing power purchases driven by customer growth and increased demand for electricity. FortisBC Electric's rate application assumes forecast average rate base of approximately $1,145 million for 2012 and $1,212 million for 2013. • Effective June 1, 2011, the BCUC approved a refundable interim increase of 1.4% in FortisBC Electric customer rates arising from an increase in purchased power costs due to an interim increase in BC Hydro rates.
FortisAlberta	• In December 2010 the AUC issued its decision on FortisAlberta's August 2010 Compliance Filing, which incorporated the AUC's decision, received in July 2010, on the Company's 2010 and 2011 Distribution Tariff Application ("DTA"). The December 2010 decision approved the Company's distribution revenue requirements of $368 million for 2011. Final distribution electricity rates and rate riders were also approved, effective January 1, 2011. • During the first quarter of 2011, the AUC initiated its proceeding to finalize the allowed ROE for 2011, review capital structure and consider whether a return to a formula-based approach for annually setting the allowed ROE, beginning in 2012, is warranted. In the absence of a formula-based approach, the AUC is expected to consider how the allowed ROE will be set for 2012. A hearing on the proceeding has been completed and a decision is expected in the fourth quarter of 2011. • In March 2011 FortisAlberta filed its 2012 and 2013 DTA. The Company requested approval of revenue requirements of $410 million for 2012 and $447 million for 2013, for rate increases of 8.2% and 6.9%, respectively. The DTA also proposes approximately $776 million in gross capital expenditures over the two-year period. The requested rate increases are driven primarily by rate base growth associated with investment in utility infrastructure, which results in increased amortization costs and interest expense. The Company has proposed a schedule for the DTA proceeding that would include a hearing in late October 2011 with a final decision expected in the first quarter of 2012. • In June 2011 the AUC issued its decision regarding the prudency of additional capital expenditures above $104 million related to the Company's Automated Metering Project. In its decision, the AUC concluded that the full amount of the forecast total project cost of $126 million can be included in rate base and collected in customer rates. The impact of the decision is the recognition of $2.5 million in accrued revenue and an associated regulatory asset as at June 30, 2011. The Utilities Consumer Advocate has filed a Leave to Appeal related to this decision. • In October 2010 the Central Alberta Rural Electrification Association ("CAREA") filed an application with the AUC seeking a declaration that, effective January 1, 2012, CAREA be entitled to service any new customer wishing to obtain electricity for use on property within CAREA's service area and that FortisAlberta be restricted to serving only those customers that are not being provided service by CAREA. FortisAlberta has intervened in the proceeding. • The AUC has initiated a process to reform utility rate regulation in Alberta. The AUC has expressed its intention to apply a PBR formula to electricity distribution rates. FortisAlberta is currently assessing PBR and will participate fully in the AUC process. In July 2011 FortisAlberta, along with other distribution utilities operating under the AUC's jurisdiction, submitted their PBR proposals to the AUC. The Company's submission outlines its views as to how PBR should be implemented at FortisAlberta.
Newfoundland Power	• In November 2010 the PUB approved Newfoundland Power's application to defer the recovery of expected increased costs of $2.4 million, due to expiring regulatory amortizations in 2011. • In December 2010 the PUB approved Newfoundland Power's application to: (i) adopt the accrual method of accounting for OPEB costs, effective January 1, 2011; (ii) recover the transitional regulatory asset balance of approximately $53 million, associated with adoption of accrual accounting, over a 15-year period; and (iii) adopt an OPEB cost-variance deferral account to capture differences between OPEB expense calculated in accordance with Canadian GAAP and OPEB expense approved by the PUB for rate-setting purposes. • In December 2010 Newfoundland Power received approval from the PUB for an overall average 0.8% increase in customer electricity rates, effective January 1, 2011, mainly resulting from the PUB's approval for the Company to change its accounting for OPEB costs, as described above, partially offset by the impact of the decrease in the allowed ROE for 2011.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
Newfoundland Power (cont'd)	• On January 1, 2011, new support structure arrangements with Bell Aliant Inc. ("Bell Aliant" or the "Purchaser") went into effect. Bell Aliant will buy back 40% of all joint-use poles and related infrastructure owned by Newfoundland Power for approximately $46 million, representing approximately 5% of the Company's rate base. The support structure arrangements are subject to certain conditions, including PUB approval of the sale of 40% of the Company's joint-use poles, which were to be met by June 30, 2011, or either party could terminate the new arrangements. Newfoundland Power filed an application with the PUB in February 2011 seeking approval of the transaction. On July 22, 2011, the PUB issued an order that denied Newfoundland Power's application requesting approval of the proposed sale. The PUB indicated that there was lack of evidence to support the customer benefits related to this transaction. The Company is presently reviewing the order and its options, including whether to appeal the PUB decision or file further evidence to support the PUB's reconsideration of the proposed sale. The purchase price continues to be held in escrow and Newfoundland Power is negotiating with the Purchaser to facilitate the successful completion of the transaction. In the event of termination, the rights and recourses under the original Joint-Use Facilities Partnership Agreement will remain in effect for both parties. Due to the timing of the PUB decision, and range of options available, it is not practicable at this time to determine the financial impact, if any, the decision has on Newfoundland Power. The new support structure arrangements are not expected to materially impact Newfoundland Power's ability to earn a reasonable return on its rate base in 2011. Newfoundland Power anticipates the proceeds from the sale of the poles will be used to pay down credit facility borrowings and maintain the utility's capital structure at 45% common equity. • In April 2011 the PUB approved Newfoundland Power's application requesting an Optional Seasonal Rate for domestic customers effective July 1, 2011. This Optional Seasonal Rate charges a higher price for electricity consumed during the months of December through April and a lower rate during the months of May through November. The PUB also approved capital expenditures for 2011 required to facilitate implementation of the Optional Seasonal Rate and the use of an Optional Rates Revenue and Cost Recovery Account that provides for the deferral of annual cost and revenue effects associated with implementing the Optional Seasonal Rate. • Effective July 1, 2011, the PUB approved an overall average increase in customer electricity rates of approximately 8%. The increase in rates was primarily due to the normal annual operation of the Rate Stabilization Plan of Newfoundland and Labrador Hydro ("Newfoundland Hydro"). Variances in the cost of fuel used to generate electricity that Newfoundland Hydro sells to Newfoundland Power are captured and flowed through to Newfoundland Power customers through the operation of Newfoundland Power's Rate Stabilization Account. The increase in rates, principally due to increased fuel prices, will have no impact on Newfoundland Power's earnings. • As part of its 2011 Budget, the Government of Newfoundland and Labrador introduced the Energy Rebate which will result in the 8% provincial portion of the Harmonized Goods and Services Tax on home energy purchases, including electricity, being refunded to residential customers. This rebate is expected to be in place by October 1, 2011. Details regarding the Energy Rebate's application and implementation date are expected to be finalized over the summer months for implementation in early fall 2011. • In July 2011 Newfoundland Power filed an application with the PUB requesting approval for its 2012 Capital Expenditure Plan totalling approximately $77 million. • The Company is currently assessing the requirement for it to file an application with the PUB to recover expected increased costs in 2012.
Maritime Electric	• In November 2010 Maritime Electric signed an Accord with the Government of PEI. The Accord covers the period from March 1, 2011 through February 29, 2016. Under the terms of the Accord, the Government of PEI is assuming responsibility for the cost of replacement energy and the monthly operating and maintenance costs related to the NB Power Point Lepreau Nuclear Generating Station ("Point Lepreau"), effective March 1, 2011 until Point Lepreau is fully refurbished, which is expected by fall 2012. The Government of PEI is financing these costs, which will be recovered from customers beginning when Point Lepreau returns to service. In the event that Point Lepreau does not return to service by fall 2012, the Government of PEI reserves the right to cease the monthly payments. As permitted by IRAC, replacement energy costs incurred during the refurbishment of Point Lepreau up to the end of February 2011 were deferred by Maritime Electric and totalled approximately $47 million. The deferred costs are included in rate base.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
Maritime Electric (cont'd)	• The nature and timing of the recovery of the deferred costs related to Point Lepreau is subject to further review by the PEI Energy Commission (the "Commission"), which was recently established by the Government of PEI. Having authority under the *Public Inquiries Act,* the co-chaired five-member Commission's goal is to examine and provide advice on ways in which PEI's high cost of electricity can be structurally reduced and/or stabilized over the longer term. In carrying out this goal, the Commission will, amongst other things, examine and provide recommendations on long-term ownership and management of electricity on PEI and provide advice and recommendations as to the future role of the PEI Energy Corporation, IRAC (as it relates to electricity) and the Office of Energy Efficiency. • The Accord also provides for the financing by the Government of PEI of costs associated with Maritime Electric's termination of the Dalhousie Unit Participation Agreement. The costs will be subsequently collected from customers over a period to be established by the Government of PEI. As a result of the Accord, including the favourable impact on purchased power costs of the new five-year power purchase agreement between Maritime Electric and NB Power, customer electricity rates decreased by approximately 14% effective March 1, 2011, at which time a two-year customer rate freeze commenced.
FortisOntario	• In non-rebasing years, customer electricity distribution rates are set using inflationary factors less an efficiency target under the Third-Generation Incentive Rate Mechanism ("IRM") as prescribed by the OEB. In March 2011 the OEB published the applicable inflationary and efficiency targets, which resulted in minimal changes in base customer electricity distribution rates at FortisOntario's operations Fort Erie, Gananoque and Port Colborne. • In November 2010 the OEB approved an NSA pertaining to Algoma Power's electricity distribution rate application for customer rates, effective December 1, 2010 through December 31, 2011, using a 2011 forward test year. The rates reflect an approved allowed ROE of 9.85% on a deemed equity component of capital structure of 40%. The overall impact of the OEB rate decision on an overall average customer's electricity bill was an increase of 3.8%, including rate riders and other charges. • The present form of Third-Generation IRM will not accommodate Algoma Power's customer rate structure and the RRRP Program; therefore, Algoma Power is consulting with the intervener community to develop a form of incentive rate-making that may be used between rebasing periods. Due to regulations in Ontario associated with the RRRP Program, customer electricity distribution rates at Algoma Power are tied to the average changes in rates of other electric utilities in Ontario. Pending these consultations, Algoma Power will file for incentive rate-making for customer electricity distribution rates, effective January 1, 2012. • FortisOntario expects to file a COS Application in 2012 for harmonized electricity distribution rates in Fort Erie, Port Colborne and Gananoque, effective January 1, 2013, using a 2013 forward test year. The timing of the filing of the COS Application corresponds with the ending of the period that the current Third-Generation IRM applies to FortisOntario.
Caribbean Utilities	• In March 2011 Caribbean Utilities confirmed to the ERA that the RCAM, as provided in the Company's transmission and distribution licence, yielded no customer rate adjustment effective June 1, 2011. • In March 2011 the ERA approved US$134 million of proposed non-generation installation expenditures as requested by Caribbean Utilities in its 2011-2015 Capital Investment Plan ("CIP"). The 2011-2015 CIP was prepared upon the basis of the Company's application to the ERA for a delay in any new generation installation until there is more certainty in growth forecasts. The remaining US$85 million of the CIP relates to new generation installation, which would be subject to a competitive solicitation process with the next generating unit currently scheduled for installation in 2014. • In July 2011 the ERA approved Caribbean Utilities request to use US GAAP for regulatory reporting purposes, beginning January 1, 2012.
Fortis Turks and Caicos	• In March 2011 Fortis Turks and Caicos submitted its 2010 annual regulatory filing outlining the Company's performance in 2010. Included in the filing were the calculations, in accordance with the utility's licence, of rate base for 2010 of US$142 million and cumulative shortfall in achieving allowable profits as at December 31, 2010 of US$49 million. • In June 2011 Fortis Turks and Caicos was advised by the interim Government of the Turks and Caicos Islands of its intention to conduct an independent review of the regulatory framework for the electricity sector in the Turks and Caicos Islands. The review is expected to be completed during the third quarter of 2011. Fortis Turks and Caicos expects to file a new Rate Variance Application in 2011. • Effective September 2011 the interim Government of the Turks and Caicos Islands plans to implement a carbon tax which will be applicable to Fortis Turks and Caicos but which may not be permitted to be passed onto Fortis Turks and Caicos' customers. If the carbon tax is implemented as scheduled, the potential impact on Fortis Turks and Caicos is a decrease in earnings of approximately $1 million for 2011. Management is working with the interim Government for a mutually beneficial resolution of the above issue.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between June 30, 2011 and December 31, 2010.

Significant Changes in the Consolidated Balance Sheets (Unaudited) between June 30, 2011 and December 31, 2010

Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Cash	189	The increase was driven by cash on hand related to a portion of the proceeds from the June 2011 $300 million common share issue.
Accounts receivable	(66)	The decrease was primarily due to the impact of a seasonal decrease in sales and the lower commodity cost of natural gas reflected in customer rates at the FortisBC Energy companies and the discontinuance of the consolidation method of accounting for the financial results of Belize Electricity in June 2011. The decrease was partially offset by the operation of the equal payment plans for customers mainly at the FortisBC Energy companies and Newfoundland Power.
Inventories	(60)	The decrease was driven by the normal seasonal reduction of gas in storage at the FortisBC Energy companies, due to higher consumption during the winter months.
Other assets	109	The increase was due to the discontinuance of the consolidation method of accounting for the financial results of Belize Electricity in June 2011, due to the expropriation of the Company by the GOB, and the resulting classification of the book value of the Corporation's previous investment in Belize Electricity, including unrealized foreign currency translation losses of $28 million, to other assets.
Utility capital assets	84	The increase primarily related to $487 million invested in electricity and gas systems, partially offset by the impact of the discontinuance of the consolidation method of accounting for Belize Electricity, and amortization costs and customer contributions for the six months ended June 30, 2011.
Short-term borrowings	(201)	The decrease was driven by lower borrowings at the FortisBC Energy companies due to seasonality of operations and repayment of borrowings by way of equity injection from Fortis with a portion of the proceeds from the June 2011 equity issue.
Accounts payable and accrued charges	(106)	The decrease was mainly due to: (i) a change in the fair market value of the natural gas derivatives at the FortisBC Energy companies; (ii) lower amounts owing for purchased natural gas at the FortisBC Energy companies and purchased power at FortisBC Electric and Newfoundland Power, associated with seasonality of operations; and (iii) the discontinuance of the consolidation method of accounting for Belize Electricity. The decrease was partially offset by higher accounts payable at the Waneta Expansion Limited Partnership ("Waneta Partnership") associated with the construction of the Waneta hydroelectric generation expansion project ("Waneta Expansion Project"), and at Caribbean Utilities due to an increase in fuel costs.
Regulatory liabilities – current and long-term	66	The increase was mainly due to: (i) increased deferrals at the FortisBC Energy companies; (ii) an increase in the provision for asset removal and site restoration costs at FortisAlberta; and (iii) increases in the weather normalization and other deferral accounts at Newfoundland Power. The increased deferrals at the FortisBC Energy companies were associated with the Rate Stabilization Deferral Account ("RSDA"), reflecting the accumulation of over-recovered costs of providing service to customers during the first half of 2011, the MCRA, as amounts collected in customer rates were in excess of actual mid-stream gas-delivery costs, and the Revenue Stabilization Adjustment Mechanism, reflecting the margin impact of actual gas volumes consumed by residential and commercial customers being in excess of forecast gas volumes.

Significant Changes in the Consolidated Balance Sheets (Unaudited) between June 30, 2011 and December 31, 2010 (cont'd)

Balance Sheet Account	Increase / (Decrease) *($ millions)*	Explanation
Regulatory liabilities – current and long-term (cont'd)		The above increases were partially offset by the impact of the discontinuance of the consolidation method of accounting for Belize Electricity.
Shareholders' equity (before non-controlling interests)	433	The increase was driven by the issuance of $300 million in common shares in June 2011. The net proceeds are being used to repay borrowings under credit facilities, fund equity injections into the utilities in western Canada and the non-regulated Waneta Partnership in support of infrastructure investment, and for general corporate purposes. The remainder of the increase in shareholders' equity was primarily due to: (i) the reclassification of $28 million of unrealized foreign currency translation losses related to the Corporation's previous investment in Belize Electricity from accumulated other comprehensive loss to other long-term assets; (ii) net earnings attributable to common equity shareholders for the six months ended June 30, 2011, less common share dividends; and (iii) the issuance of common shares under the Corporation's dividend reinvestment and stock option plans.

LIQUIDITY AND CAPITAL RESOURCES

The table below outlines the Corporation's consolidated sources and uses of cash for the three and six months ended June 30, 2011, as compared to the same periods in 2010, followed by a discussion of the nature of the variances in cash flows.

Summary of Consolidated Cash Flows (Unaudited)						
Periods Ended June 30	**Quarter Ended**			**Year-to-Date**		
($ millions)	**2011**	2010	Variance	**2011**	2010	Variance
Cash, Beginning of Period	**86**	92	(6)	**109**	85	24
Cash Provided by (Used in):						
Operating Activities	**228**	204	24	**527**	405	122
Investing Activities	**(268)**	(229)	(39)	**(487)**	(405)	(82)
Financing Activities	**252**	3	249	**149**	(14)	163
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**-**	1	(1)	**-**	-	-
Cash, End of Period	**298**	71	227	**298**	71	227

Operating Activities: Cash flow from operating activities, after working capital adjustments, was $24 million higher quarter over quarter and $122 million higher year to date compared to the same period last year. The increases were primarily due to: (i) higher earnings; (ii) the collection from customers of regulator-approved increased amortization costs, mainly at FortisAlberta; and (iii) favourable changes in working capital and regulatory deferral accounts. The favourable working capital changes were driven by greater impacts of seasonality at the FortisBC Energy companies and higher Alberta Electric System Operator ("AESO") net transmission-related receipts and payments at FortisAlberta. The favourable changes in regulatory deferral accounts related mainly to the increase in the RSDA at the FortisBC Energy companies, due to the accumulation of over-recovered costs of providing service to customers during 2011.

Investing Activities: Cash used in investing activities was $39 million higher quarter over quarter and $82 million higher year to date compared to the same period last year. The increases were driven by capital spending related to the non-regulated Waneta Expansion Project and an increase in capital spending at FortisAlberta year to date, partially offset by lower capital spending at FortisBC Electric and an increase in contributions received in aid of construction.

Financing Activities: Cash provided by financing activities was $249 million higher quarter over quarter and $163 million higher year to date compared to the same period last year. The increases were mainly due to higher proceeds from the issuance of common shares, lower repayments of long-term debt, higher advances from non-controlling interests and higher proceeds from long-term debt, partially offset by unfavourable variances in short-term borrowings and lower net borrowings under committed credit facilities classified as long term. Proceeds from the issuance of preferences shares were also lower year to date compared to the same period in 2010.

Net repayments of short-term borrowings were $102 million during the second quarter of 2011 compared to net proceeds from short-term borrowings of $55 million during the same quarter in 2010. Net repayments of short-term borrowings were $200 million year to date compared to $126 million during the same period in 2010. The changes in short-term borrowings were driven by the FortisBC Energy companies due to seasonality differences and timing of repayments using proceeds from equity injections from the Corporation.

Proceeds from long-term debt, net of issue costs, repayments of long-term debt and capital lease obligations and net borrowings under committed credit facilities for the quarter and year to date compared to the same periods last year are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs (Unaudited)						
Periods Ended June 30	**Quarter Ended**			**Year-to-Date**		
($ millions)	**2011**	2010	Variance	**2011**	2010	Variance
Caribbean Utilities [(1)]	**29**	-	29	**29**	-	29
Other	**1**	-	1	**1**	-	1
Total	**30**	-	30	**30**	-	30

(1) Issued in June 2011, 15-year US$11.25 million 4.85% and 20-year US$18.75 million 5.10% unsecured notes. The net proceeds are being used to repay current installments on long-term debt and short-term borrowings and to finance capital expenditures.

Repayments of Long-Term Debt and Capital Lease Obligations (Unaudited)						
Periods Ended June 30	**Quarter Ended**			**Year-to-Date**		
($ millions)	**2011**	2010	Variance	**2011**	2010	Variance
FortisBC Energy Companies	**-**	(1)	1	**-**	(1)	1
Maritime Electric	**-**	(15)	15	**-**	(15)	15
Caribbean Utilities	**(12)**	(15)	3	**(12)**	(15)	3
Fortis Properties	**(2)**	(38)	36	**(4)**	(52)	48
Corporate [(1)]	**-**	(125)	125	**-**	(125)	125
Other	**(4)**	(2)	(2)	**(6)**	(4)	(2)
Total	**(18)**	(196)	178	**(22)**	(212)	190

(1) In April 2010 FHI redeemed in full for cash its $125 million 8% Capital Securities with proceeds from borrowings under the Corporation's committed credit facility.

Net Borrowings Under Committed Credit Facilities (Unaudited)						
Periods Ended June 30	**Quarter Ended**			**Year-to-Date**		
($ millions)	**2011**	2010	Variance	**2011**	2010	Variance
FortisAlberta	**5**	20	(15)	**17**	60	(43)
FortisBC Electric	**7**	21	(14)	**7**	12	(5)
Newfoundland Power	**10**	2	8	**23**	13	10
Corporate	**36**	143	(107)	**26**	72	(46)
Total	**58**	186	(128)	**73**	157	(84)

Borrowings under credit facilities by the utilities are primarily in support of their capital expenditure programs and/or for working capital requirements. Repayments are primarily financed through the issuance of long-term debt, cash from operations and/or equity injections from Fortis. From time to time, proceeds from preference share, common share and long-term debt issues are used to repay borrowings under the Corporation's committed credit facility.

Advances of approximately $40 million and $57 million for the quarter and year to date, respectively, were received from non-controlling interests in the Waneta Partnership to finance capital expenditures related to the Waneta Expansion Project.

In June 2011 Fortis issued 9.1 million common shares for gross proceeds of $300 million. The net proceeds of $288 million are being used to repay borrowings under credit facilities and finance equity injections into the utilities in western Canada and the Waneta Expansion Project in support of infrastructure investment, and for general corporate purposes.

In January 2010 Fortis completed a $250 million offering of 10 million First Preference Shares, Series H. The net proceeds of approximately $242 million were used to repay borrowings under the Corporation's committed credit facility and fund an equity injection into FEI.

Common share dividends paid during the second quarter of 2011 were $36 million, net of $15 million in dividends reinvested, compared to $36 million, net of $13 million in dividends reinvested, paid during the same quarter of 2010. Common share dividends paid year-to-date 2011 were $71 million, net of $31 million in dividends reinvested, compared to $69 million, net of $28 million in dividends reinvested, paid year-to-date 2010. The dividend paid per common share for each of the first and second quarters of 2011 was $0.29 compared to $0.28 for each of the first and second quarters of 2010. The weighted average number of common shares outstanding for the quarter and year to date were 177.1 million and 175.8 million, respectively, compared to 172.4 million and 172.0 million, respectively, for the same periods in 2010.

CONTRACTUAL OBLIGATIONS

Consolidated contractual obligations of Fortis over the next five years and for periods thereafter, as at June 30, 2011, are outlined in the following table. A detailed description of the nature of the obligations is provided in the MD&A for the year ended December 31, 2010 and below, where applicable.

Contractual Obligations (Unaudited) **As at June 30, 2011** *($ millions)*	**Total**	Due within 1 year	Due in years 2 and 3	Due in years 4 and 5	Due after 5 years
Long-term debt	**5,700**	318	289	695	4,398
Waneta Partnership promissory note	**72**	-	-	-	72
Brilliant Terminal Station	**59**	3	5	5	46
Gas purchase contract obligations (1)	**474**	269	183	22	-
Power purchase obligations (2)					
FortisBC Electric	**2,887**	44	88	82	2,673
FortisOntario	**434**	44	98	102	190
Maritime Electric	**217**	55	79	69	14
Capital cost (3)	**470**	13	34	38	385
Joint-use asset and share service agreements	**64**	4	8	7	45
Office lease – FortisBC Electric	**17**	2	3	3	9
Operating lease obligations	**120**	18	29	27	46
Defined benefit pension funding contributions (4)	**77**	33	39	2	3
Other	**22**	3	8	7	4
Total	**10,613**	806	863	1,059	7,885

(1) Based on index prices as at June 30, 2011

(2) Excludes power purchase obligations of Belize Electricity, due to the discontinuance of the consolidation method of accounting for the financial results of the utility, effective June 20, 2011

(3) Maritime Electric has entitlement to approximately 4.7% of the output from Point Lepreau for the life of the unit. As part of its participation agreement, the Company is obligated to pay its share of capital and operating costs of the unit, which have been included in the table above. However, as a result of the Accord, the Government of PEI is assuming responsibility for the payment of the

monthly operating and maintenance costs related to Point Lepreau, effective March 1, 2011 until Point Lepreau is fully refurbished, which is expected by fall 2012.

(4) Consolidated defined benefit pension funding contributions include current service, solvency and special funding amounts. The contributions are based on estimates provided under the latest completed actuarial valuations, which generally provide funding estimates for a period of three to five years from the date of the valuations. As a result, actual pension funding contributions may be higher than these estimated amounts, pending completion of the next actuarial valuations for funding purposes, which are expected to be performed as of the following dates for the larger defined benefit pension plans:

December 31, 2011	Newfoundland Power
December 31, 2012	FortisBC Energy (covering non-unionized employees)
December 31, 2013	FortisBC Energy (covering unionized employees)
December 31, 2013	FortisBC Electric

The estimate of defined benefit pension funding contributions above includes the impact of the outcome of the December 31, 2010 actuarial valuations, completed during the first half of 2011, associated with the defined benefit pension plan at FortisBC Energy, covering unionized employees, and at FortisBC Electric, as well as other revised actuarial estimates.

Other contractual obligations, which are not reflected in the above table, did not change from that disclosed in the MD&A for the year ended December 31, 2010 except that $20 million of FEVI government loans are now included in long-term debt obligations due within one year as a result of an expected repayment within one year.

For a discussion of the nature and amount of the Corporation's consolidated capital expenditure program, which is not included in the contractual obligations table above, refer to the "Capital Program" section of this MD&A.

CAPITAL STRUCTURE

The Corporation's principal businesses of regulated gas and electricity distribution require ongoing access to capital to allow the utilities to fund maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. Fortis generally finances a significant portion of acquisitions at the corporate level with proceeds from common share, preference share and long-term debt issues. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 40% equity, including preference shares, and 60% debt, as well as investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in the utilities' customer rates.

The consolidated capital structure of Fortis is presented in the following table.

Capital Structure (Unaudited)	**As at**			
	June 30, 2011		December 31, 2010	
	($ millions)	***(%)***	*($ millions)*	*(%)*
Total debt and capital lease obligations (net of cash) (1)	**5,559**	**54.5**	5,914	58.4
Preference shares (2)	**912**	**8.9**	912	9.0
Common shareholders' equity	**3,738**	**36.6**	3,305	32.6
Total (3)	**10,209**	**100.0**	10,131	100.0

(1) Includes long-term debt and capital lease obligations, including current portion, and short-term borrowings, net of cash

(2) Includes preference shares classified as both long-term liabilities and equity

(3) Excludes amounts related to non-controlling interests

The change in the capital structure was driven by the public issuance of $300 million in common shares in June 2011 combined with common shares issued under the Corporation's dividend reinvestment and stock option plans and the reclassification of unrealized foreign currency translation losses related to the Corporation's previous investment in Belize Electricity to other long-term assets. Also contributing to the change in the capital structure was net earnings applicable to common shares, net of dividends, lower short-term borrowings and higher cash on hand.

CREDIT RATINGS

The Corporation's credit ratings are as follows:

Standard & Poor's	A- (long-term corporate and unsecured debt credit rating)
DBRS	A(low) (unsecured debt credit rating)

The credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level, the Corporation's reasonable credit metrics and its demonstrated ability and continued focus on acquiring and integrating stable regulated utility businesses financed on a conservative basis.

CAPITAL PROGRAM

Capital investment in infrastructure is required to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred. Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred.

A breakdown of the $519 million in gross capital expenditures by segment for the first half of 2011 is provided in the following table.

Gross Consolidated Capital Expenditures (Unaudited) [(1)]
Year-to-Date June 30, 2011
($ millions)

FortisBC Energy Companies	Fortis Alberta [(2)]	FortisBC Electric	Newfoundland Power	Other Regulated Electric Utilities – Canadian	**Total Regulated Utilities - Canadian**	**Regulated Electric Utilities - Caribbean** [(3)]	**Non-Regulated - Utility** [(4)]	**Fortis Properties**	**Total**
114	171	53	31	19	**388**	**40**	**82**	**9**	**519**

(1) Relates to cash payments to acquire or construct utility capital assets, income producing properties and intangible assets, as reflected in the consolidated statement of cash flows. Includes asset removal and site restoration expenditures, net of salvage proceeds, for those utilities where such expenditures are permissible in rate base in 2011. Excludes capitalized amortization and non-cash equity component of the allowance for funds used during construction.
(2) Includes payments made to AESO for investment in transmission-related capital projects
(3) Includes capital expenditures at Belize Electricity up to June 20, 2011
(4) Includes non-regulated generation, mainly related to the Waneta Expansion Project, and corporate capital expenditures

There has been no material change in forecast gross consolidated capital expenditures for 2011 from the approximate $1.2 billion forecast as was disclosed in the MD&A for the year ended December 31, 2010. Planned capital expenditures are based on detailed forecasts of energy demand, weather, cost of labour and materials, as well as other factors, including economic conditions, which could change and cause actual expenditures to differ from forecasts.

There were no material changes in the overall expected level, nature and timing of the Corporation's significant capital projects from those disclosed in the MD&A for the year ended December 31, 2010, except as described below.

In April 2011 Fortis Properties filed a development application to construct a 12-storey office building in St. John's, Newfoundland, subject to municipal government approval. The $50 million project will feature 145,000 square feet of Class A office space and include 262 parking spaces. It is expected to be completed in the second half of 2013.

Approximately $10 million of the originally estimated forecast project cost for 2011 related to FEI's Customer Care Enhancement Project is expected to be incurred in the first half of 2012. The total project cost is expected to be approximately $116 million.

During the first quarter of 2011, FortisAlberta substantially completed its $126 million Automated Metering Project, which involved the replacement of approximately 466,000 conventional meters.

During the second quarter of 2011, FEI substantially completed construction of its estimated $214 million LNG storage facility. The facility is currently being filled and is expected to be available for the upcoming winter heating season.

Over the five-year period 2011 through 2015, consolidated gross capital expenditures are expected to be approximately $5.7 billion, up from $5.5 billion as disclosed in the MD&A for the year ended December 31, 2010. The increase largely reflects higher capital expenditures at the FortisBC Energy companies, partially offset by the exclusion of capital expenditures at Belize Electricity due to the discontinuance of the consolidation method of accounting for the financial results of the Company. Approximately 61% of the capital spending is expected to be incurred at the regulated electric utilities, driven by FortisAlberta and FortisBC Electric. Approximately 23% and 16% of the capital spending is expected to be incurred at the regulated gas utilities and at the non-regulated operations, respectively. Capital expenditures at the regulated utilities are subject to regulatory approval.

CASH FLOW REQUIREMENTS

At the subsidiary level, it is expected that operating expenses and interest costs will generally be paid out of operating cash flows, with varying levels of residual cash flow available for subsidiary capital expenditures and/or dividend payments to Fortis. Borrowings under credit facilities may be required from time to time to support seasonal working capital requirements. Cash required to complete subsidiary capital expenditure programs is also expected to be financed from a combination of borrowings under credit facilities, equity injections from Fortis and long-term debt issues.

The Corporation's ability to service its debt obligations and pay dividends on its common and preference shares is dependent on the financial results of the operating subsidiaries and the related cash payments from these subsidiaries. Certain regulated subsidiaries may be subject to restrictions which may limit their ability to distribute cash to Fortis. Cash required of Fortis to support subsidiary capital expenditure programs and finance acquisitions is expected to be derived from a combination of borrowings under the Corporation's committed credit facility and proceeds from the issuance of common shares, preference shares and long-term debt. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends.

As at June 30, 2011, management expects consolidated long-term debt maturities and repayments to average approximately $260 million annually over the next five years. The combination of available credit facilities and relatively low annual debt maturities and repayments provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

As the hydroelectric assets and water rights of the Exploits River Hydro Partnership ("Exploits Partnership") had been provided as security for the Exploits Partnership term loan, the expropriation of such assets and rights by the Government of Newfoundland and Labrador constituted an event of default under the loan. The term loan is without recourse to Fortis and was approximately $57 million as at June 30, 2011 (December 31, 2010 - $58 million). The lenders of the term loan have not demanded accelerated repayment. The scheduled repayments under the term loan are being made by Nalcor, a Crown corporation, acting as an agent for the Government of Newfoundland and Labrador with respect to the expropriation matters. For further information refer to Note 30 to the Corporation's 2010 annual audited consolidated financial statements.

Except for the debt at the Exploits Partnership, as discussed above, Fortis and its subsidiaries were in compliance with debt covenants as at June 30, 2011 and are expected to remain compliant throughout 2011.

CREDIT FACILITIES

As at June 30, 2011, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.1 billion, of which $1.5 billion was unused, including $409 million unused under the Corporation's $600 million committed revolving credit facility. The credit facilities are syndicated almost entirely with the seven largest Canadian banks, with no one bank holding more than 25% of these facilities. Approximately $2.0 billion of the total credit facilities are committed facilities with maturities between 2012 and 2015.

The following table outlines the credit facilities of the Corporation and its subsidiaries.

Credit Facilities (Unaudited)				**As at**	
($ millions)	Corporate and Other	Regulated Utilities	Fortis Properties	**June 30, 2011**	December 31, 2010
Total credit facilities	645	1,436	13	**2,094**	2,109
Credit facilities utilized:					
Short-term borrowings	-	(154)	(3)	**(157)**	(358)
Long-term debt (including current portion)	(191)	(101)	-	**(292)**	(218)
Letters of credit outstanding	(1)	(120)	-	**(121)**	(124)
Credit facilities unused	453	1,061	10	**1,524**	1,409

As at June 30, 2011 and December 31, 2010, certain borrowings under the Corporation's and subsidiaries' credit facilities were classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

In February 2011 Maritime Electric renewed its unsecured committed revolving credit facility, which matures annually in March. The unsecured committed revolving credit facility was reduced from $60 million to $50 million.

In April 2011 FortisBC Electric renegotiated and amended its credit facility agreement resulting in an extension to the maturity of the Company's $150 million unsecured committed revolving credit facility with $100 million now maturing in May 2014 and $50 million now maturing in May 2012.

In April 2011 FHI extended the maturity date of its $30 million unsecured committed revolving credit facility to May 2012.

In June 2011 Newfoundland Power renegotiated and amended its $100 million unsecured committed credit facility, obtaining an extension to the maturity of the facility to August 2015 from August 2013. The amended credit facility agreement reflects a decrease in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

FINANCIAL INSTRUMENTS

The carrying values of the Corporation's consolidated financial instruments approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments, except as follows:

Financial Instruments (Unaudited)	**As at**			
	June 30, 2011		December 31, 2010	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Waneta Partnership promissory note	**43**	**41**	42	40
Long-term debt, including current portion (1)	**5,700**	**6,427**	5,669	6,431
Preference shares, classified as debt (2)	**320**	**346**	320	344

(1) Carrying value as at June 30, 2011 excludes unamortized deferred financing costs of $41 million (December 31, 2010 - $42 million) and capital lease obligations of $41 million (December 31, 2010 - $38 million).

(2) Preference shares classified as equity do not meet the definition of a financial instrument; however, the estimated fair value of the Corporation's $592 million preference shares classified as equity was $612 million as at June 30, 2011 (December 31, 2010 – $615 million).

Excluded from the above table is the $112 million asset as at June 30, 2011 related to the Corporation's previous investment in Belize Electricity. The fair value of this financial asset is not determinable at this time.

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, as is the case with the Waneta Partnership promissory note, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a market credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs. The fair value of the Corporation's preference shares is determined using quoted market prices.

Risk Management: The Corporation's earnings from, and net investments in, self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. Foreign exchange gains and losses on the translation of US dollar-denominated interest expense partially offsets the foreign exchange losses and gains on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of Caribbean Utilities, Fortis Turks and Caicos, FortisUS Energy Corporation and BECOL is the US dollar.

As at June 30, 2011, US$529 million of the US$594 million corporately issued long-term debt (December 31, 2010 – US$590 million of US$590 million) had been designated as an effective hedge of the Corporation's net investments in self-sustaining foreign subsidiaries. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar borrowings designated as effective hedges are recognized in other comprehensive income and help offset unrealized foreign currency gains and losses on the net investments in self-sustaining foreign subsidiaries, which are also recognized in other comprehensive income.

Effective June 20, 2011, the Corporation's asset associated with its previous investment in Belize Electricity, recorded in other long-term assets, does not qualify for hedge accounting as Belize Electricity is no longer a self-sustaining foreign subsidiary of Fortis. As a result, approximately US$65 million of corporately issued debt that previously hedged the former investment in Belize Electricity is no longer an effective hedge. Effective June 20, 2011, foreign exchange gains and losses on the translation of the asset associated with Belize Electricity and the corporately issued US dollar denominated debt that previously qualified as a hedge of the investment are required to be recognized in earnings. This change in accounting treatment is not expected to have a material impact on consolidated earnings of Fortis. As at June 30, 2011, all of the Corporation's net investments in self-sustaining foreign subsidiaries were hedged (December 31, 2010 - 99%).

From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and fuel and natural gas prices through the use of derivative financial instruments. The Corporation and its subsidiaries do not hold or issue derivative financial instruments for trading purposes.

The following table summarizes the valuation of the Corporation's derivative financial instruments.

Derivative Financial Instruments (Unaudited)					**As at**	
	June 30, 2011				December 31, 2010	
Liability	**Term to Maturity *(years)***	**Number of Contracts**	**Carrying Value *($ millions)***	**Estimated Fair Value *($ millions)***	Carrying Value *($ millions)*	Estimated Fair Value *($ millions)*
Foreign exchange forward contracts	**< 1**	**2**	**-**	**-**	-	-
Fuel option contracts	**< 1**	**2**	**(1)**	**(1)**	-	-
Natural gas derivatives:						
Swaps and options	**Up to 4**	**183**	**(117)**	**(117)**	(162)	(162)
Gas purchase contract premiums	**Up to 3**	**50**	**(3)**	**(3)**	(5)	(5)

The foreign exchange forward contracts are held by the FortisBC Energy companies. During 2010 FEI entered into a foreign exchange forward contract to hedge the cash flow risk related to approximately US$5 million remaining to be paid under a contract for the implementation of a customer information system. FEVI also hedges the cash flow risk related to less than US$1 million remaining to be paid under a contract for the construction of the LNG storage facility on Vancouver Island.

The fuel option contracts are held by Caribbean Utilities. During the first quarter of 2011, the Company's Fuel Price Volatility Management Program was approved by the regulator to reduce the impact of volatility in fuel prices on customer rates. In April 2011 Caribbean Utilities entered into two fuel option contracts.

The natural gas derivatives are held by the FortisBC Energy companies and are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The price risk-management strategy of the FortisBC Energy companies aims to improve the likelihood that natural gas prices remain competitive with electricity rates, temper gas price volatility on customer rates and reduce the risk of regional price discrepancies.

The changes in the fair values of the foreign exchange forward contracts, fuel option contracts and natural gas derivatives are deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates. The fair values of the derivative financial instruments were recorded in accounts payable as at June 30, 2011 and as at December 31, 2010.

The foreign exchange forward contracts are valued using the present value of cash flows based on a market foreign exchange rate and the foreign exchange forward rate curve. The fuel option contracts are valued using published market prices for similar commodities. The natural gas derivatives are valued using the present value of cash flows based on market prices and forward curves for the commodity cost of natural gas. The fair values of the foreign exchange forward contracts, fuel option contracts and natural gas derivatives are estimates of the amounts that would have to be received or paid to terminate the outstanding contracts as at the balance sheet dates.

The fair values of the Corporation's financial instruments, including derivatives, reflect point-in-time estimates based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows.

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $121 million, as at June 30, 2011, the Corporation had no off-balance sheet arrangements, such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities, that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

BUSINESS RISK MANAGEMENT

There were no changes in the Corporation's significant business risks during the first half of 2011 from those disclosed in the MD&A for the year ended December 31, 2010, except for those described below.

Investment in Belize: In June 2011 the GOB expropriated the Corporation's investment in Belize Electricity. Fortis has initiated proceedings for compensation from the GOB for the value of the Corporation's previous investment in Belize Electricity. The Corporation is exposed to risk associated with the amount of compensation to be paid for its previous investment in Belize Electricity, the timeliness of payment of the compensation and the ability of the GOB to pay the compensation owing to Fortis.

The GOB has indicated publicly that it does not intend to expropriate BECOL. As at June 30, 2011, the book value of the Corporation's investment in BECOL was $150 million.

Transition to New Accounting Standards: In June 2011 the Ontario Securities Commission ("OSC") issued a decision allowing Fortis and its reporting issuer subsidiaries to prepare their financial statements, effective January 1, 2012, in accordance with US GAAP without qualifying as U.S. Securities and Exchange Commission ("SEC") Issuers. The Corporation and its reporting issuer subsidiaries, therefore, will be adopting US GAAP as opposed to International Financial Reporting Standards ("IFRS") at the above date. Earnings to be recognized under US GAAP are expected to be closely aligned with earnings recognized under Canadian GAAP, mainly due to the continued recognition of regulatory assets and liabilities. A transition to IFRS would likely have resulted in the derecognition of some, or perhaps all, of the Corporation's regulatory assets and liabilities and significant volatility in the Corporation's consolidated earnings. For further information, refer to the "Future Accounting Standards" section of this MD&A.

Capital Resources and Liquidity Risk - Credit Ratings: Fortis and its regulated utilities do not anticipate any material adverse rating actions by the credit rating agencies in the near term. During the first half of 2011, DBRS confirmed its existing credit ratings for Newfoundland Power and Caribbean Utilities and in July 2011 Moody's Investors Service confirmed its existing credit ratings for Newfoundland Power and FEI.

Defined Benefit Pension Plan Performance: As at June 30, 2011, the fair value of the Corporation's consolidated defined benefit pension plan assets was $753 million, up $26 million, or 3.6%, from $727 million as at December 31, 2010.

Labour Relations: The collective agreement between FortisBC Electric and Local 378 of the Canadian Office and Professional Employees Union ("COPE") expired January 31, 2011. The Company and COPE have commenced negotiations. In the interim, the current collective agreement remains in full effect until such time as the parties negotiate and ratify a new agreement.

CHANGE IN ACCOUNTING TREATMENT

Effective January 1, 2011, as approved by the regulator, the cost of OPEB plans at Newfoundland Power is being expensed and recovered in customer rates based on the accrual method of accounting for OPEBs. Additionally, the Company's transitional regulatory OPEB asset of $53 million as at December 31, 2010 is being amortized on a straight-line basis over 15 years. During the three and six months ended June 30, 2011, operating expenses increased by approximately $2 million and $4 million, respectively, as a result of this change in accounting treatment. Prior to January 1, 2011, the cost of OPEB plans at Newfoundland Power was being expensed and recovered in customer rates based on the cash payments made.

FUTURE ACCOUNTING CHANGES

Adoption of New Accounting Standards: Due to continued uncertainty around the timing and adoption of a rate-regulated accounting standard by the International Accounting Standards Board, Fortis has evaluated the option of adopting US GAAP, as opposed to IFRS, and has decided to adopt US GAAP effective January 1, 2012.

Canadian securities rules allow a reporting issuer to prepare and file its financial statements in accordance with US GAAP by qualifying as an SEC Issuer. An SEC Issuer is defined under the Canadian rules as an issuer that: (i) has a class of securities registered with the SEC under Section 12 of the *U.S. Securities Exchange Act of 1934*, as amended (the "Exchange Act"); or (ii) is required to file reports under Section 15(d) of the Exchange Act. The Corporation is currently not an SEC Issuer. Therefore, on June 6, 2011, the Corporation filed an application with the OSC seeking relief, pursuant to National Policy 11-203 – *Process for Exemptive Relief Applications in Multiple Jurisdictions,* to permit the Corporation and its reporting issuer subsidiaries to prepare their financial statements in accordance with US GAAP without qualifying as SEC Issuers ("the Exemption"). On June 9, 2011, the OSC issued its decision and granted the Exemption for financial years commencing on or after January 1, 2012 but before January 1, 2015, and interim periods therein. The Exemption will terminate in respect of financial statements for annual and interim periods commencing on or after the earlier of: (i) January 1, 2015; or (ii) the date on which the Corporation ceases to have activities subject to rate regulation.

The Corporation's application of Canadian GAAP currently relies on US GAAP for guidance on accounting for rate-regulated activities. The adoption of US GAAP in 2012 is, therefore, expected to result in fewer significant changes to the Corporation's accounting policies as compared to accounting policy changes that may have resulted from the adoption of IFRS. US GAAP guidance on accounting for rate-regulated activities allows the economic impact of rate-regulated activities to be recognized in the consolidated financial statements in a manner consistent with the timing by which amounts are reflected in customer rates. Fortis believes that the continued application of rate-regulated accounting, and the associated recognition of regulatory assets and liabilities under US GAAP, accurately reflects the impact that rate regulation has on the Corporation's consolidated financial position and results of operations.

The Corporation has developed a three-phase plan to adopt US GAAP effective January 1, 2012. The following is an overview of the activities under each phase and their current status.

Phase I - Scoping and Diagnostics: Phase I consisted of project initiation and awareness; project planning and resourcing; and identification of high-level differences between US GAAP and Canadian GAAP in order to highlight areas where detailed analysis would be needed to determine and conclude as to the nature and extent of financial statement impacts. External accounting and legal advisors were engaged during this phase to assist the Corporation's internal US GAAP conversion team and to provide technical input and expertise as required. Phase I commenced in the fourth quarter of 2010 and is now complete.

Phase II - Analysis and Development: Phase II consists of detailed diagnostics and evaluation of the financial statement impacts of adopting US GAAP based on the high-level assessment conducted under Phase I; identification and design of any new, or changes to, operational or financial business processes; initial staff training and audit committee orientation; and development of required solutions to address identified issues.

Phase II had included planned activities for the registration of securities as required to achieve SEC Issuer status and an assessment of ongoing requirements of the United States *Sarbanes-Oxley Act* ("US SOX"), including auditor attestation of internal controls over financial reporting, and a comparison of the requirements under US SOX to those required in Canada under National Instrument 52-109 - *Certification of Disclosure in Issuers' Annual and Interim Filings*. These activities are no longer required or applicable following the Exemption granted by the OSC as discussed above.

Phase II of the plan commenced in January 2011. Based on the research and analysis completed to date, and the Corporation's continued ability to apply rate-regulated accounting policies under US GAAP, the differences between US GAAP and Canadian GAAP are not expected to have a material impact on consolidated earnings. In addition, adoption of US GAAP is expected to result in limited changes in balance sheet classifications, and additional disclosure requirements. The impact on information systems and internal controls over financial reporting is expected to be minimal.

Phase III - Implementation and Review: Phase III involves the implementation of all financial reporting, systems and internal control changes required by the Corporation to prepare and file its consolidated financial statements based on US GAAP beginning in 2012 and the communication of associated impacts.

The Corporation will prepare and file, in accordance with Canadian GAAP, its annual audited consolidated financial statements for the year ending December 31, 2011. The Corporation intends to voluntarily prepare and file, in accordance with US GAAP, its annual audited consolidated financial statements for the year ending December 31, 2011 and the comparative period. The voluntary filing is expected to be completed prior to March 31, 2012. Beginning with the first quarter of 2012, the Corporation's unaudited interim consolidated financial statements will be prepared and filed in accordance with US GAAP.

Phase III has commenced and will conclude when the Corporation prepares and files, in accordance with US GAAP, its annual audited consolidated financial statements for the year ending December 31, 2012.

Financial Statement Impacts - US GAAP: The areas identified to date where differences between US GAAP and Canadian GAAP are expected to have the most significant financial statement impacts are as follows:

Employee future benefits: Under Canadian GAAP, the accrued benefit asset or liability associated with defined benefit plans is recognized on the balance sheet with a reconciliation of the recognized asset or liability to the funded or unfunded status being disclosed in the notes to the consolidated financial statements. The accrued benefit asset or liability excludes unamortized balances related to past service costs, actuarial gains and losses and transitional obligations or assets which have not yet been recognized.

US GAAP requires recognition of the funded or unfunded status of defined benefit plans on the balance sheet, with the opening unamortized balances related to past service costs, actuarial gains and losses and transitional obligations recognized on the balance sheet as a component of accumulated other comprehensive income. Changes to past service costs, actuarial gains and losses and transitional obligations which are not immediately recognized as components of net pension expense are required to be recognized in other comprehensive income. Entities with activities subject to rate regulation would recognize the opening unamortized balances as regulatory assets or liabilities for recovery from, or refund to, customers in future rates, with subsequent changes to these balances recognized as net pension expense, where required by the regulator, or otherwise as a change in the regulatory asset or liability. Therefore, upon adoption of US GAAP, the Corporation's rate-regulated subsidiaries, with the exception of FortisAlberta as discussed below, will recognize the unfunded or funded status of its defined benefit plans on the balance sheet with the above-noted unamortized balances recognized as regulatory assets or liabilities.

FortisAlberta has historically recovered its OPEB costs on a cash basis, as opposed to an accrual basis, and will likely continue to do so as ordered by its regulator. Therefore, FortisAlberta's regulatory asset associated with OPEB costs does not meet the criteria for recognition under US GAAP.

Additional differences between Canadian GAAP and US GAAP in the accounting for defined benefit plans include the determination of the measurement date and the period over which pension expense is recognized. Canadian GAAP allows for the use of a measurement date up to three months prior to the date of an entity's fiscal year end. US GAAP requires the entity's fiscal year end to be used as the measurement date. Canadian GAAP allows for the use of an attribution period that extends beyond the date when the credited service period ends, under specific circumstances, for defined benefit pension plans. US GAAP allows for the use of an attribution period up to the date when credited service ends for defined benefit pension plans.

The above differences will impact the calculation of the Corporation's consolidated benefit obligation which will be mostly offset by a corresponding change to regulatory assets or liabilities.

The impact of adopting US GAAP with respect to accounting for pensions and OPEBs for regulated and non-regulated entities is not expected to have a material impact on the Corporation's consolidated earnings.

Brilliant Power Purchase Agreement ("BPPA"): FortisBC Electric expects that the BPPA will qualify for capital lease accounting under US GAAP. While the requirement to evaluate whether an arrangement includes a lease is similar between Canadian GAAP and US GAAP, the effective date for prospective adoption of lease accounting guidance differs, resulting in an accounting difference for the BPPA.

Fulfillment of the BPPA is dependent on the use of a specific asset, the Brilliant Hydroelectric Plant ("Brilliant"), and the conveyance unto FortisBC Electric the right to use that asset under an arrangement between FortisBC Electric and the legal owner of Brilliant. The BPPA qualifies as a capital lease as the present value of the minimum lease payments to be made by FortisBC Electric represents recovery of the entire amount of the initial investment in Brilliant by the legal owner over the term of the arrangement.

The anticipated effect of recognizing Brilliant as a capital lease retrospectively under US GAAP is the recognition of a capital lease asset with an offsetting obligation under capital lease for an equivalent amount. Each reporting period, the total amount of amortization and interest expense to be recognized under capital lease accounting is expected to differ from the amount paid under the BPPA and recovered through current electricity rates as permitted by the regulator. This timing difference is expected to be recognized as a regulatory asset, with amounts recovered through electricity rates expected to equal the combined amount of the capitalized lease asset and interest on the lease obligation over the term of the BPPA. Since US GAAP allows for entities to account for the effects of rate-regulation, the impact of adopting capital lease accounting for Brilliant is not expected to have an effect on the Corporation's consolidated earnings.

Reclassification of preference shares: Currently, under Canadian GAAP, the Corporation's First Preference Shares, Series C and Series E are classified as long-term liabilities with associated dividends classified as finance charges. Under US GAAP, the Series C and Series E First Preference Shares do not meet the criteria for recognition as a financial liability. Therefore, upon adoption of US GAAP, the Corporation will reclassify the Series C and Series E First Preference Shares from long-term debt to shareholders' equity. The associated dividends will be recorded as earnings attributable to preference equity shareholders.

Corporate income taxes: Under Canadian GAAP, the Corporation has calculated and recognized corporate income taxes using substantially enacted corporate income tax rates. Under US GAAP, the Corporation is required to calculate and record corporate income taxes based on enacted corporate income tax rates. Therefore, upon adoption of US GAAP, the Corporation will be required to recognize the impact of the difference between enacted tax rates and substantially enacted tax rates related to the calculation of the Part VI.1 tax deduction associated with preference share dividends. The retroactive adjustment to recognize the Part VI.1 tax deduction based on enacted corporate income tax rates under US GAAP will result in a reduction in opening retained earnings and annual earnings thereafter. However, the amount of the adjustments are not expected to be material and will reverse once pending Canadian federal legislation is passed resulting in the enactment of the proposed corporate income tax rate changes.

The above items do not represent a complete list of expected differences between US GAAP and Canadian GAAP. Analysis remains ongoing and additional areas where the Corporation's financial statements may be materially impacted could be identified prior to the Corporation's voluntary preparation and filing, in accordance with US GAAP, of its annual audited consolidated financial statements for the year ending December 31, 2011. Any additional areas where significant adjustments may be required will be disclosed as they are determined. As previously indicated, no material adjustments to the Corporation's consolidated earnings under US GAAP are currently expected due to the Corporation's continued ability to apply rate-regulated accounting policies.

The quantification and reconciliation of the Corporation's consolidated financial statements from Canadian GAAP to US GAAP for 2010 is scheduled for completion by September 30, 2011. The quantification and reconciliation of the Corporation's consolidated financial statements from Canadian GAAP to US GAAP for 2011 interim and annual reporting periods is scheduled for completion by March 31, 2012.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's interim unaudited consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Additionally, certain estimates and judgments are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period they become known.

Interim financial statements may also employ a greater use of estimates than the annual financial statements. There were no material changes in the nature of the Corporation's critical accounting estimates during the first half of 2011 from those disclosed in the MD&A for the year ended December 31, 2010.

Contingencies: The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with ordinary course business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's consolidated financial position or results of operations. There were no material changes in the Corporation's contingent liabilities from those disclosed in the MD&A for the year ended December 31, 2010.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended September 30, 2009 through June 30, 2011. The quarterly information has been obtained from the Corporation's interim unaudited consolidated financial statements which, in the opinion of management, have been prepared in accordance with Canadian GAAP and as required by utility regulators. The timing of the recognition of certain assets, liabilities, revenue and expenses, as a result of regulation, may differ from that otherwise expected using Canadian GAAP for non-regulated entities. The differences and nature of regulation are disclosed in Notes 2, 3 and 5 to the Corporation's 2010 annual audited consolidated financial statements. The quarterly financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results (Unaudited)		**Net Earnings Attributable to Common Equity**		
	Revenue	**Shareholders**	**Earnings per Common Share**	
Quarter Ended	*($ millions)*	*($ millions)*	**Basic** *($)*	**Diluted** *($)*
June 30, 2011	850	58	0.33	0.33
March 31, 2011	1,164	117	0.67	0.65
December 31, 2010	1,036	85	0.49	0.47
September 30, 2010	720	45	0.26	0.26
June 30, 2010	835	55	0.32	0.32
March 31, 2010	1,073	100	0.58	0.56
December 31, 2009	1,020	81	0.48	0.46
September 30, 2009	665	36	0.21	0.21

A summary of the past eight quarters reflects the Corporation's continued organic growth and growth from acquisitions, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of gas and electricity demand and water flows, as well as the timing and recognition of regulatory decisions. Revenue is also affected by the cost of fuel and purchased power and the commodity cost of natural gas, which are flowed through to customers without markup. Given the diversified nature of the Fortis subsidiaries, seasonality may vary. Most of the annual earnings of the FortisBC Energy companies are realized in the first and fourth quarters. Financial results from June 20, 2011 reflect the discontinuance of the consolidation method of accounting for the financial results of Belize Electricity. For further information refer to the "Corporate Overview" section of this MD&A. Financial results for the third quarter ended September 30, 2010 reflected the favourable cumulative retroactive impact associated with a 2010-2011 regulatory rate decision for FortisAlberta. The commissioning of the Vaca hydroelectric generating facility in March 2010 has favourably impacted financial results since that date. Financial results for the fourth quarter ended December 31, 2009 reflected the favourable cumulative retroactive impact, from January 1, 2009, associated with an increase in the allowed ROE and equity component of capital structure for FortisAlberta. To a lesser degree, financial results from October 2009 have been favourably impacted by the acquisition of Algoma Power.

June 2011/June 2010: Net earnings attributable to common equity shareholders were $58 million, or $0.33 per common share, for the second quarter of 2011 compared to earnings of $55 million, or $0.32 per common share, for the second quarter of 2010. A discussion of the variances between the financial results for the second quarter of 2011 and the second quarter of 2010 is provided in the "Financial Highlights" section of this MD&A.

March 2011/March 2010: Net earnings attributable to common equity shareholders were $117 million, or $0.67 per common share, for the first quarter of 2011 compared to earnings of $100 million, or $0.58 per common share, for the first quarter of 2010. The increase was mainly due to improved performance at the regulated utilities in western Canada driven by overall growth in infrastructure investment, higher energy sales at FortisBC Electric and FortisAlberta, the timing of recording of the cumulative impact of FortisAlberta's and FEWI's 2010 revenue requirements decisions and a $1 million gain on the sale of property, partially offset by the timing of and regulator-approved increase in certain operating expenses at the FortisBC Energy companies. Earnings also increased due to lower corporate business development costs and higher non-regulated hydroelectric generation in Belize during the first quarter of 2011.

December 2010/December 2009: Net earnings attributable to common equity shareholders were $85 million, or $0.49 per common share, for the fourth quarter of 2010 compared to earnings of $81 million, or $0.48 per common share, for the fourth quarter of 2009. The increase was mainly due to improved performance at Canadian Regulated Electric Utilities, non-regulated hydroelectric generation operations in Belize and lower effective corporate income taxes at Fortis Properties, partially offset by lower earnings from the FortisBC Energy companies and Caribbean Regulated Electric Utilities. Improved performance at Canadian Regulated Electric Utilities was driven by overall growth in electrical infrastructure investment, combined with customer growth at FortisAlberta and the higher allowed ROE at FortisBC Electric. Earnings were lower quarter over quarter at the

FortisBC Energy companies, as a result of higher regulator-approved operating expenses and the timing of the recognition of these increased expenses, and at Caribbean Regulated Electric Utilities, mainly due to lower electricity sales associated with cooler-than-normal temperatures experienced in the region and the inability of Belize Electricity to earn a fair and reasonable return due to regulatory challenges. Earnings for the fourth quarter of 2009 were reduced by $5 million related to the expensing of the project cost overrun associated with the conversion of Whistler customer appliances from propane to natural gas, but were favourably impacted by a one-time $3 million tax adjustment at FortisOntario.

September 2010/September 2009: Net earnings attributable to common equity shareholders were $45 million, or $0.26 per common share, for the third quarter of 2010 compared to earnings of $36 million, or $0.21 per common share, for the third quarter of 2009. The increase in earnings was mainly due to improved performance at the regulated electric utilities in western Canada and non-regulated hydroelectric generation operations, partially offset by a higher loss incurred at the FortisBC Energy companies and higher corporate expenses. Improved performance at the regulated electric utilities in western Canada was due to higher allowed ROEs and/or equity component of capital structure, growth in electrical infrastructure investment combined with an increase in the number of customers at FortisAlberta, partially offset by a weather-related decrease in electricity sales at FortisBC Electric and lower net transmission revenue at FortisAlberta. The increase in earnings' contribution from non-regulated hydroelectric generation operations was the result of increased production in Belize, driven by higher rainfall and the commissioning of the Vaca hydroelectric generating facility in March 2010, and lower finance charges. The higher loss at the FortisBC Energy companies quarter over quarter largely related to increased operating and maintenance expenses at FEI that were approved by the BCUC as part of the recent NSA. The loss in the third quarter of 2010, however, was reduced by $4 million (after tax) related to the BCUC-approved reversal of most of the project cost overrun previously expensed in the fourth quarter of 2009 associated with the conversion of Whistler customer appliances from propane to natural gas. The increase in corporate expenses was associated with higher preference share dividends, partially offset by lower finance charges.

SUBSEQUENT EVENTS

On July 11, 2011, the Board of Directors of Central Vermont Public Service Corporation ("CVPS") determined that the unsolicited acquisition proposal from Gaz Métro Limited Partnership was a "Superior Proposal", as that term is defined in the Merger Agreement between Fortis and CVPS announced on May 30, 2011 (the "Merger Agreement") and that CVPS elected to terminate the Merger Agreement in accordance with its terms. Prior to such termination taking effect, the Merger Agreement provided Fortis the right to require CVPS to negotiate with Fortis for at least five business days with respect to any changes to the terms of the Merger Agreement proposed by Fortis. Fortis agreed to waive such right in exchange for the prompt payment by CVPS to Fortis of the US$17.5 million termination fee plus US$2.0 million for expenses as set forth in the Merger Agreement, thereby resulting in the termination of the Merger Agreement. Fortis received the $18.8 million (US$19.5 million) payment on July 12, 2011.

On July 15, 2011, the underwriters of the Corporation's June 2011 $300 million public offering of 9.1 million common shares exercised their over-allotment option and purchased an additional 1.24 million common shares of Fortis for gross proceeds of approximately $41 million.

OUTLOOK

The Corporation's significant capital expenditure program, which is expected to be approximately $5.7 billion over the five-year period 2011 through 2015, should drive growth in earnings and dividends.

The Corporation continues to pursue acquisitions for profitable growth, focusing on regulated electric and natural gas utilities in the United States and Canada. Fortis will also pursue growth in its non-regulated businesses in support of its regulated utility growth strategy.

OUTSTANDING SHARE DATA

As at August 2, 2011, the Corporation had issued and outstanding 186.3 million common shares; 5.0 million First Preference Shares, Series C; 8.0 million First Preference Shares, Series E; 5.0 million First Preference Shares, Series F; 9.2 million First Preference Shares, Series G; and 10.0 million First Preference Shares, Series H. Only the common shares of the Corporation have voting rights.

The number of common shares of Fortis that would be issued if all outstanding stock options, convertible debt and First Preference Shares, Series C and E were converted as at August 2, 2011 is as follows:

Conversion of Securities into Common Shares (Unaudited) As at August 2, 2011 **Security**	**Number of Common Shares** *(millions)*
Stock Options	**4.9**
Convertible Debt	**1.4**
First Preference Shares, Series C	**4.2**
First Preference Shares, Series E	**6.7**
Total	**17.2**

Additional information, including the Fortis 2010 Annual Information Form, Management Information Circular and Annual Report, is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisinc.com.

FORTIS INC.

Interim Consolidated Financial Statements
For the three and six months ended June 30, 2011 and 2010
(Unaudited)

Fortis Inc.
Consolidated Balance Sheets (Unaudited)
As at
(in millions of Canadian dollars)

	June 30, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	$ 298	$ 109
Accounts receivable (Note 20)	589	655
Prepaid expenses	23	17
Regulatory assets (Note 5)	196	241
Inventories (Note 6)	108	168
Future income taxes	21	14
	1,235	1,204
Assets held for sale (Note 7)	45	45
Other assets (Note 8)	277	168
Regulatory assets (Note 5)	889	831
Future income taxes	13	16
Utility capital assets	8,286	8,202
Income producing properties	557	560
Intangible assets	327	324
Goodwill	1,548	1,553
	$ 13,177	$ 12,903
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings (Note 20)	$ 157	$ 358
Accounts payable and accrued charges	847	953
Dividends payable	57	54
Income taxes payable	39	30
Regulatory liabilities (Note 5)	71	60
Current installments of long-term debt and capital lease obligations (Note 9)	321	56
Future income taxes	3	6
	1,495	1,517
Other liabilities	313	308
Regulatory liabilities (Note 5)	522	467
Future income taxes	640	623
Long-term debt and capital lease obligations (Note 9)	5,379	5,609
Preference shares	320	320
	8,669	8,844
Shareholders' equity		
Common shares (Note 10)	2,915	2,578
Preference shares	592	592
Contributed surplus	13	12
Equity portion of convertible debentures	5	5
Accumulated other comprehensive loss (Note 12)	(69)	(94)
Retained earnings	874	804
	4,330	3,897
Non-controlling interests	178	162
	4,508	4,059
	$ 13,177	$ 12,903

Contingent Liabilities and Commitments (Note 21)
See accompanying Notes to Interim Consolidated Financial Statements

Fortis Inc.
Consolidated Statements of Earnings (Unaudited)
For the periods ended June 30
(in millions of Canadian dollars, except per share amounts)

	Quarter Ended		Six Months Ended	
	2011	2010	**2011**	2010
Revenue	**$ 850**	$ 835	**$ 2,014**	$ 1,908
Expenses				
Energy supply costs	**358**	367	**961**	919
Operating	**213**	202	**425**	404
Amortization	**103**	97	**206**	191
	674	666	**1,592**	1,514
Operating income	**176**	169	**422**	394
Finance charges (Note 14)	**92**	88	**183**	178
Earnings before corporate taxes	**84**	81	**239**	216
Corporate taxes (Note 15)	**15**	15	**45**	43
Net earnings	**$ 69**	$ 66	**$ 194**	$ 173
Net earnings attributable to:				
Non-controlling interests	**$ 3**	$ 3	**$ 4**	$ 4
Preference equity shareholders	**8**	8	**15**	14
Common equity shareholders	**58**	55	**175**	155
	$ 69	$ 66	**$ 194**	$ 173
Earnings per common share (Note 10)				
Basic	**$ 0.33**	$ 0.32	**$ 1.00**	$ 0.90
Diluted	**$ 0.33**	$ 0.32	**$ 0.99**	$ 0.88

See accompanying Notes to Interim Consolidated Financial Statements

Fortis Inc.
Consolidated Statements of Retained Earnings (Unaudited)
For the periods ended June 30
(in millions of Canadian dollars)

	Quarter Ended		Six Months Ended	
	2011	2010	**2011**	2010
Balance at beginning of period	**$ 870**	$ 767	**$ 804**	$ 763
Net earnings attributable to common and preference equity shareholders	**66**	63	**190**	169
	936	830	**994**	932
Dividends on common shares	**(54)**	(49)	**(105)**	(145)
Dividends on preference shares classified as equity	**(8)**	(8)	**(15)**	(14)
Balance at end of period	**$ 874**	$ 773	**$ 874**	$ 773

See accompanying Notes to Interim Consolidated Financial Statements

Fortis Inc.
Consolidated Statements of Comprehensive Income (Unaudited)
For the periods ended June 30
(in millions of Canadian dollars)

	Quarter Ended		Six Months Ended	
	2011	2010	**2011**	2010
Net earnings	**$ 69**	$ 66	**$ 194**	$ 173
Other comprehensive (loss) income				
Unrealized foreign currency translation (losses) gains on net investments in self-sustaining foreign operations	**(3)**	28	**(18)**	8
Gains (losses) on hedges of net investments in self-sustaining foreign operations	**4**	(19)	**18**	(5)
Corporate tax (recovery) expense	**(1)**	3	**(3)**	1
Unrealized foreign currency translation gains (losses), net of hedging activities and tax (Note 12)	**-**	12	**(3)**	4
Comprehensive income	**$ 69**	$ 78	**$ 191**	$ 177
Comprehensive income attributable to:				
Non-controlling interests	**$ 3**	$ 3	**$ 4**	$ 4
Preference equity shareholders	**8**	8	**15**	14
Common equity shareholders	**58**	67	**172**	159
	$ 69	$ 78	**$ 191**	$ 177

See accompanying Notes to Interim Consolidated Financial Statements

Fortis Inc.

Consolidated Statements of Cash Flows (Unaudited)
For the periods ended June 30
(in millions of Canadian dollars)

	Quarter Ended		Six Months Ended	
	2011	2010	**2011**	2010
		(Note 23)		(Note 23)
Operating activities				
Net earnings	**$ 69**	$ 66	**$ 194**	$ 173
Items not affecting cash:				
Amortization - utility capital assets and income producing properties	**94**	87	**188**	170
Amortization - intangible assets	**10**	9	**20**	20
Amortization - other	**(1)**	1	**(2)**	1
Future income taxes	**1**	2	**(1)**	(1)
Other	**7**	-	**5**	2
Change in long-term regulatory assets and liabilities	**-**	(4)	**18**	-
	180	161	**422**	365
Change in non-cash operating working capital	**48**	43	**105**	40
	228	204	**527**	405
Investing activities				
Change in other assets and other liabilities	**(2)**	1	**(5)**	3
Capital expenditures - utility capital assets	**(268)**	(234)	**(487)**	(413)
Capital expenditures - income producing properties	**(6)**	(3)	**(9)**	(9)
Capital expenditures - intangible assets	**(12)**	(7)	**(23)**	(10)
Contributions in aid of construction	**19**	14	**31**	24
Proceeds on sale of utility capital assets and income producing properties	**1**	-	**6**	-
	(268)	(229)	**(487)**	(405)
Financing activities				
Change in short-term borrowings	**(102)**	55	**(200)**	(126)
Proceeds from long-term debt, net of issue costs	**30**	-	**30**	-
Repayments of long-term debt and capital lease obligations	**(18)**	(196)	**(22)**	(212)
Net borrowings under committed credit facilities	**58**	186	**73**	157
Advances from non-controlling interests	**40**	1	**57**	1
Issue of common shares, net of costs and dividends reinvested	**290**	3	**301**	11
Issue of preference shares, net of costs	**-**	-	**-**	242
Dividends				
Common shares, net of dividends reinvested	**(36)**	(36)	**(71)**	(69)
Preference shares	**(8)**	(8)	**(15)**	(14)
Subsidiary dividends paid to non-controlling interests	**(2)**	(2)	**(4)**	(4)
	252	3	**149**	(14)
Effect of exchange rate changes on cash and cash equivalents	**-**	1	**-**	-
Change in cash and cash equivalents	**212**	(21)	**189**	(14)
Cash and cash equivalents, beginning of period	**86**	92	**109**	85
Cash and cash equivalents, end of period	**$ 298**	$ 71	**$ 298**	$ 71

Supplementary Information to Consolidated Statements of Cash Flows (Note 17)
See accompanying Notes to Interim Consolidated Financial Statements

1. DESCRIPTION OF THE BUSINESS

Nature of Operations

Fortis Inc. ("Fortis" or the "Corporation") is principally an international distribution utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation assets, and commercial office and retail space and hotels, which are treated as two separate segments. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each reporting segment operates as an autonomous unit, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following outlines each of the Corporation's reportable segments and is consistent with the basis of segmentation as disclosed in the Corporation's 2010 annual audited consolidated financial statements.

REGULATED UTILITIES

The Corporation's interests in regulated gas and electric utilities in Canada and the Caribbean by utility are as follows:

a. *Regulated Gas Utilities - Canadian:* Includes the FortisBC Energy companies, which is comprised of FortisBC Energy Inc. ("FEI") (formerly Terasen Gas Inc.), FortisBC Energy (Vancouver Island) Inc. ("FEVI") (formerly Terasen Gas (Vancouver Island) Inc.) and FortisBC Energy (Whistler) Inc. (formerly Terasen Gas (Whistler) Inc.).

b. *Regulated Electric Utilities - Canadian:* Includes FortisAlberta; FortisBC Electric (formerly referred to as FortisBC); Newfoundland Power; and Other Canadian Electric Utilities, which includes Maritime Electric and FortisOntario. FortisOntario mainly includes Canadian Niagara Power Inc., Cornwall Street Railway, Light and Power Company, Limited and Algoma Power Inc.

c. *Regulated Electric Utilities - Caribbean:* Includes Caribbean Utilities, in which Fortis holds an approximate 59% controlling ownership interest; wholly owned Fortis Turks and Caicos, which includes FortisTCI Limited (formerly P.P.C. Limited) and Atlantic Equipment & Power (Turks and Caicos) Ltd.; and Belize Electricity, in which Fortis held an approximate 70% controlling ownership interest up to June 20, 2011. Effective June 20, 2011, the Government of Belize enacted legislation leading to the expropriation of the Corporation's investment in Belize Electricity and, as a result of no longer exercising control over the operations of the utility, Fortis discontinued the consolidation method of accounting for the financial results of Belize Electricity (Note 8).

NON-REGULATED - FORTIS GENERATION

Fortis Generation includes the financial results of non-regulated assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State.

NON-REGULATED - FORTIS PROPERTIES

Fortis Properties owns and operates 21 hotels, comprised of more than 4,100 rooms, in eight Canadian provinces and approximately 2.7 million square feet of commercial office and retail space primarily in Atlantic Canada.

CORPORATE AND OTHER

The Corporate and Other segment includes Fortis net corporate expenses, net expenses of non-regulated FortisBC Holdings Inc. ("FHI") (formerly Terasen Inc.) corporate-related activities, and the financial results of FHI's 30% ownership interest in CustomerWorks Limited Partnership and of FHI's non-regulated wholly owned subsidiary FortisBC Alternative Energy Services Inc. (formerly Terasen Energy Services Inc.).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These interim consolidated financial statements do not include all of the information and disclosures required in the annual consolidated financial statements and should be read in conjunction with the Corporation's 2010 annual audited consolidated financial statements. Interim results will fluctuate due to the seasonal nature of gas and electricity demand and water flows, as well as the timing and recognition of regulatory decisions. Because of natural gas consumption patterns, most of the annual earnings of the FortisBC Energy companies are realized in the first and fourth quarters. Given the diversified group of companies, seasonality may vary.

All amounts are presented in Canadian dollars unless otherwise stated.

These interim consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") for interim financial statements, following the same accounting policies and methods as those used in preparing the Corporation's 2010 annual audited consolidated financial statements, except as described below.

Effective January 1, 2011, as approved by the regulator, the cost of other post-employment benefit ("OPEB") plans at Newfoundland Power is being expensed and recovered in customer rates based on the accrual method of accounting for OPEBs. Additionally, the Company's transitional regulatory OPEB asset of $53 million as at December 31, 2010 is being amortized on a straight-line basis over 15 years. During the three and six months ended June 30, 2011, operating expenses increased by approximately $2 million and $4 million, respectively, as a result of this change in accounting treatment. Prior to January 1, 2011, the cost of OPEB plans at Newfoundland Power was being expensed and recovered in customer rates based on the cash payments made.

3. FUTURE ACCOUNTING CHANGES

Effective January 1, 2012, the Corporation will be required to adopt a new set of accounting standards. Publicly accountable enterprises in Canada were required to adopt International Financial Reporting Standards ("IFRS") effective January 1, 2011; however, qualifying entities with rate-regulated activities were granted an optional one-year deferral for the adoption of IFRS, due to continued uncertainty around the timing and adoption of a rate-regulated accounting standard by the International Accounting Standards Board ("IASB"). As a qualifying entity with rate-regulated activities, Fortis has elected to opt for the one-year deferral and, therefore, will continue to prepare its consolidated financial statements in accordance with Part V of the Canadian Institute of Chartered Accountants Handbook for all interim and annual periods ending on or before December 31, 2011.

Due to continued uncertainty around the timing and adoption of a rate-regulated accounting standard by the IASB, Fortis has evaluated the option of adopting United States generally accepted accounting principles ("US GAAP"), as opposed to IFRS, and has decided to adopt US GAAP effective January 1, 2012. Canadian securities rules allow a reporting issuer to prepare and file its financial statements in accordance with US GAAP by qualifying as a U.S. Securities and Exchange Commission ("SEC") Issuer. An SEC Issuer is defined under the Canadian rules as an issuer that: (i) has a class of securities registered with the SEC under Section 12 of the *U.S. Securities Exchange Act of 1934*, as amended (the "Exchange Act"); or (ii) is required to file reports under Section 15(d) of the Exchange Act. The Corporation is not currently an SEC Issuer. Therefore, on June 6, 2011, the Corporation filed an application with the Ontario Securities Commission (the "OSC") seeking relief, pursuant to National Policy 11-203 – *Process for Exemptive Relief Applications in Multiple Jurisdictions,* to permit the Corporation and its reporting issuer subsidiaries to prepare their financial statements in accordance with US GAAP without qualifying as SEC Issuers ("the Exemption"). On June 9, 2011, the OSC issued its decision and granted the Exemption for financial years commencing on or after January 1, 2012 but before January 1, 2015, and interim periods therein. The Exemption will terminate in respect of financial statements for annual and interim periods commencing on or after the earlier of: (a) January 1, 2015; or (b) the date on which the Corporation ceases to have activities subject to rate regulation.

3. FUTURE ACCOUNTING CHANGES (cont'd)

The Corporation's application of Canadian GAAP currently relies on US GAAP for guidance on accounting for rate-regulated activities. The adoption of US GAAP in 2012 is, therefore, expected to result in fewer significant changes to the Corporation's accounting policies as compared to accounting policy changes that may have resulted from the adoption of IFRS. US GAAP guidance on accounting for rate-regulated activities allows the economic impact of rate-regulated activities to be recognized in the consolidated financial statements in a manner consistent with the timing by which amounts are reflected in customer rates. Fortis believes that the continued application of rate-regulated accounting, and the associated recognition of regulatory assets and liabilities under US GAAP, accurately reflects the impact that rate regulation has on the Corporation's consolidated financial position and results of operations.

4. USE OF ESTIMATES

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Additionally, certain estimates and judgments are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they become known.

Interim financial statements may also employ a greater use of estimates than the annual financial statements. There were no material changes in the nature of the Corporation's critical accounting estimates during the three and six months ended June 30, 2011.

5. REGULATORY ASSETS AND LIABILITIES

A summary of the Corporation's regulatory assets and liabilities is provided below. A detailed description of the nature of the Corporation's regulatory assets and liabilities is provided in Note 5 to the Corporation's 2010 annual audited consolidated financial statements.

	As at	
($ millions)	**June 30, 2011**	December 31, 2010
Regulatory assets		
Future income taxes	**595**	568
Rate stabilization accounts - FortisBC Energy companies	**101**	146
Rate stabilization accounts - electric utilities	**56**	44
Regulatory OPEB plan assets	**65**	66
Replacement energy deferral - Point Lepreau [(1)]	**47**	44
Deferred energy management costs	**27**	23
Deferred losses on disposal of utility capital assets	**21**	16
Alberta Electric System Operator ("AESO") charges deferral	**20**	19
2010 accrued distribution revenue adjustment rider	**18**	36
Income taxes recoverable on OPEB plans	**18**	18
Deferred operating costs	**16**	11
Deferred development costs for capital	**11**	11
Deferred costs - smart meters	**8**	8
Deferred lease costs	**6**	6
Deferred pension costs	**4**	5
Other regulatory assets	**72**	51
Total regulatory assets	**1,085**	1,072
Less: current portion	**(196)**	(241)
Long-term regulatory assets	**889**	831

[(1)] New Brunswick Power Point Lepreau Nuclear Generating Station

	As at	
($ millions)	**June 30, 2011**	December 31, 2010
Regulatory liabilities		
Asset removal and site restoration provision	**348**	339
Rate stabilization accounts - FortisBC Energy companies	**138**	60
Rate stabilization accounts - electric utilities	**28**	45
AESO charges deferral	**12**	9
Performance-based rate-setting incentive liabilities	**8**	8
Deferred interest	**8**	7
Southern Crossing Pipeline deferral	**7**	5
Unrecognized net gains on disposal of utility capital assets	**6**	8
2010 FEI revenue surplus	**3**	7
Unbilled revenue liability	**-**	5
Other regulatory liabilities	**35**	34
Total regulatory liabilities	**593**	527
Less: current portion	**(71)**	(60)
Long-term regulatory liabilities	**522**	467

6. INVENTORIES

	As at	
($ millions)	**June 30, 2011**	December 31, 2010
Gas in storage	**89**	148
Materials and supplies	**19**	20
	108	168

6. INVENTORIES (cont'd)

During the three and six months ended June 30, 2011, inventories of $170 million and $514 million, respectively, were expensed and reported in energy supply costs on the interim consolidated statement of earnings ($191 million and $496 million for the three and six months ended June 30, 2010, respectively). Inventories expensed to operating expenses were $4 million and $7 million for the three and six months ended June 30, 2011, respectively ($4 million and $7 million for the three and six months ended June 30, 2010, respectively). Included in inventories expensed to operating expenses was food and beverage costs at Fortis Properties of $3 million and $5 million for the three and six months ended June 30, 2011, respectively ($3 million and $5 million for the three and six months ended June 30, 2010, respectively).

7. ASSETS HELD FOR SALE

The closing of the sale of joint-use poles from Newfoundland Power to Bell Aliant Inc. (the "Purchaser") is subject to certain closing conditions, including approval by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB"), which were to be met by June 30, 2011 or either party could choose to terminate the new support structure arrangements. Newfoundland Power filed an application with the PUB in February 2011 seeking approval for the proposed sale. On July 22, 2011, the PUB issued an order that denied Newfoundland Power's application requesting approval of the proposed sale. The PUB indicated that there was lack of evidence to support the customer benefits of this transaction. The Company is presently reviewing the order and its options, including whether to appeal the PUB decision or file further evidence to support the PUB's reconsideration of the proposed sale. The purchase price continues to be held in escrow and Newfoundland Power is negotiating with the Purchaser to facilitate the successful completion of the transaction. In the event of termination of the sale, the rights and recourses under the original Joint-Use Facilities Partnership Agreement will remain in effect for both parties.

8. OTHER ASSETS

	As at	
($ millions)	**June 30, 2011**	December 31, 2010
Deferred pension costs	**138**	140
Other asset - Belize Electricity	**112**	-
Long-term accounts receivable	**9**	9
Other	**18**	19
	277	168

As a result of no longer exercising control over the operations of Belize Electricity, Fortis discontinued the consolidation method of accounting for the financial results of the Company, effective June 20, 2011. The book value of Corporation's previously 70% controlled foreign net investment in self-sustaining Belize Electricity has been recorded in other assets. The asset is denominated in US dollars and has been translated at the exchange rate prevailing at the balance sheet date. Effective June 20, 2011, the former investment in Belize Electricity does not qualify for hedge accounting and, as a result, from June 20, 2011, foreign exchange gains and losses on the translation of the asset are required to be recognized in earnings. As at June 20, 2011, approximately $28 million of unrealized foreign currency translation losses, related to the Corporation's previous foreign net investment in self-sustaining Belize Electricity, were reclassified to other assets from accumulated other comprehensive loss (Note 12).

9. LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS

($ millions)	As at June 30, 2011	December 31, 2010
Long-term debt and capital lease obligations	**5,449**	5,489
Long-term classification of committed credit facilities (Note 20)	**292**	218
Deferred debt financing costs	**(41)**	(42)
Total long-term debt and capital lease obligations	**5,700**	5,665
Less: Current installments of long-term debt and capital lease obligations	**(321)**	(56)
	5,379	5,609

10. COMMON SHARES

Authorized: an unlimited number of common shares without nominal or par value.

Issued and Outstanding	As at June 30, 2011 Number of Shares *(in thousands)*	June 30, 2011 Amount *($ millions)*	December 31, 2010 Number of Shares *(in thousands)*	December 31, 2010 Amount *($ millions)*
Common shares	**185,059**	**2,915**	174,393	2,578

Common shares issued during the period were as follows:

	Quarter Ended June 30, 2011 Number of Shares *(in thousands)*	Quarter Ended June 30, 2011 Amount *($ millions)*	Year-to-Date June 30, 2011 Number of Shares *(in thousands)*	Year-to-Date June 30, 2011 Amount *($ millions)*
Balance, beginning of period	**175,422**	**2,607**	**174,393**	**2,578**
Public offering	**9,100**	**291**	**9,100**	**291**
Dividend Reinvestment Plan	**454**	**15**	**969**	**32**
Consumer Share Purchase Plan	**11**	**-**	**24**	**1**
Stock Option Plans	**72**	**2**	**573**	**13**
Balance, end of period	**185,059**	**2,915**	**185,059**	**2,915**

In June 2011 Fortis issued 9.1 million common shares for $33.00 per common share. The common share issue resulted in gross proceeds of approximately $300 million, or approximately $291 million net of after-tax expenses.

Earnings per Common Share

The Corporation calculates earnings per common share ("EPS") on the weighted average number of common shares outstanding.

Diluted EPS is calculated using the treasury stock method for options and the "if-converted" method for convertible securities.

10. COMMON SHARES (cont'd)

Earnings per Common Share (cont'd)

EPS were as follows:

	Quarter Ended June 30					
	2011			2010		
	Earnings *($ millions)*	**Weighted Average Shares *(in millions)***	**EPS**	Earnings *($ millions)*	Weighted Average Shares *(in millions)*	EPS
Basic EPS	**58**	**177.1**	**$ 0.33**	55	172.4	$ 0.32
Effect of potential dilutive securities:						
Stock Options	**-**	**1.2**		-	0.9	
Preference Shares (Note 14)	**4**	**10.1**		4	11.9	
Convertible Debentures	**1**	**1.4**		1	1.4	
	63	**189.8**		60	186.6	
Deduct anti-dilutive impacts:						
Preference Shares	**(4)**	**(10.1)**		(4)	(11.9)	
Convertible Debentures	**(1)**	**(1.4)**		(1)	(1.4)	
Diluted EPS	**58**	**178.3**	**$ 0.33**	55	173.3	$ 0.32

	Year-to-Date June 30					
	2011			2010		
	Earnings *($ millions)*	**Weighted Average Shares *(in millions)***	**EPS**	Earnings *($ millions)*	Weighted Average Shares *(in millions)*	EPS
Basic EPS	**175**	**175.8**	**$ 1.00**	155	172.0	$ 0.90
Effect of potential dilutive securities:						
Stock Options	**-**	**1.2**		-	0.9	
Preference Shares (Note 14)	**8**	**10.1**		8	11.9	
Convertible Debentures	**1**	**1.4**		1	1.4	
	184	**188.5**		164	186.2	
Deduct anti-dilutive impacts:						
Preference Shares	**(8)**	**(10.1)**		-	-	
Diluted EPS	**176**	**178.4**	**$ 0.99**	164	186.2	$ 0.88

11. STOCK-BASED COMPENSATION PLANS

In January 2011 27,070 Deferred Share Units were granted to the Corporation's Board of Directors, representing the equity component of the Directors' annual compensation and, where opted, their annual retainers in lieu of cash. Each Deferred Share Unit ("DSU") represents a unit with an underlying value equivalent to the value of one common share of the Corporation. In March 2011 31,821 DSUs were paid out, upon the death of a Board member, at $33.06 per DSU, for a total of approximately $1.1 million.

In March 2011 45,000 Performance Share Units were granted to the President and Chief Executive Officer ("CEO") of the Corporation. Each Performance Share Unit ("PSU") represents a unit with an underlying value equivalent to the value of one common share of the Corporation. The maturation period of the March 2011 PSU grant is three years, at which time a cash payment may be made to the President and CEO after evaluation by the Human Resources Committee of the Board of Directors of the achievement of payment requirements. In March 2011 37,079 PSUs were paid out to the President and CEO of the Corporation at $33.11 per PSU, for a total of approximately $1.2 million.

11. STOCK-BASED COMPENSATION PLANS (cont'd)

The payout was made upon the three-year maturation period in respect of the PSU grant made in February 2008 and the President and CEO satisfying the payment requirements, as determined by the Human Resources Committee of the Board of Directors.

In March 2011 the Corporation granted 828,512 options to purchase common shares under its 2006 Stock Option Plan at the five-day volume weighted average trading price of $32.95 immediately preceding the date of grant. The options vest evenly over a four-year period on each anniversary of the date of grant. The options expire seven years after the date of grant. The fair value of each option granted was $4.57 per option.

The fair value was estimated at the date of grant using the Black-Scholes fair value option-pricing model and the following assumptions:

Dividend yield (%)	3.68
Expected volatility (%)	23.1
Risk-free interest rate (%)	2.00
Weighted average expected life (years)	4.5

As at June 30, 2011, 4.9 million stock options were outstanding and 2.8 million stock options were vested.

12. ACCUMULATED OTHER COMPREHENSIVE LOSS

Accumulated other comprehensive loss includes unrealized foreign currency translation gains and losses, net of hedging activities, and gains and losses on discontinued cash flow hedging activities as described in Note 3 to the Corporation's 2010 annual audited consolidated financial statements.

	Quarter Ended June 30					
	2011			2010		
($ millions)	**Opening balance April 1**	**Net change**	**Ending balance June 30**	Opening balance April 1	Net change	Ending balance June 30
Unrealized foreign currency translation (losses) gains, net of hedging activities and tax	**(93)**	**28**	**(65)**	(86)	12	(74)
Net losses on derivative instruments previously discontinued as cash flow hedges, net of tax	**(4)**	**-**	**(4)**	(5)	-	(5)
Accumulated other comprehensive (loss) income	**(97)**	**28**	**(69)**	(91)	12	(79)

	Year-to-Date June 30					
	2011			2010		
($ millions)	**Opening balance January 1**	**Net change**	**Ending balance June 30**	Opening balance January 1	Net change	Ending balance June 30
Unrealized foreign currency translation (losses) gains, net of hedging activities and tax	**(90)**	**25**	**(65)**	(78)	4	(74)
Net losses on derivative instruments previously discontinued as cash flow hedges, net of tax	**(4)**	**-**	**(4)**	(5)	-	(5)
Accumulated other comprehensive (loss) income	**(94)**	**25**	**(69)**	(83)	4	(79)

12. ACCUMULATED OTHER COMPREHENSIVE LOSS (cont'd)

The net change in accumulated other comprehensive loss for the three and six months ended June 30, 2011 includes the reclassification of approximately $28 million of unrealized foreign currency translation losses, related to the Corporation's previous foreign net investment in self-sustaining Belize Electricity, to other assets from accumulated other comprehensive loss as at June 30, 2011 (Note 8). As at June 20, 2011, unrealized after-tax foreign currency translation gains of approximately $11 million on corporately issued US dollar borrowings previously designated as an effective hedge of the Corporation's previous foreign net investment in self-sustaining Belize Electricity, remained in accumulated other comprehensive loss.

13. EMPLOYEE FUTURE BENEFITS

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, OPEB plans, defined contribution pension plans and group registered retirement savings plans ("RRSPs") for its employees. The cost of providing the defined benefit arrangements was $15 million for the quarter ended June 30, 2011 ($9 million for the quarter ended June 30, 2010) and $30 million year-to-date June 30, 2011 ($18 million year-to-date June 30, 2010). The cost of providing the defined contribution arrangements and group RRSPs for the quarter ended June 30, 2011 was $4 million ($3 million for the quarter ended June 30, 2010) and $8 million year-to-date June 30, 2011 ($7 million year-to-date June 30, 2010).

14. FINANCE CHARGES

	Quarter Ended June 30		**Year-to-Date June 30**	
($ millions)	**2011**	2010	**2011**	2010
Interest - Long-term debt and capital lease obligations	**88**	88	**179**	176
- Short-term borrowings and other	**5**	1	**9**	3
Interest charged during construction	**(5)**	(5)	**(13)**	(9)
Dividends on preference shares classified as debt (Note 10)	**4**	4	**8**	8
	92	88	**183**	178

15. CORPORATE TAXES

Corporate taxes differ from the amount that would be expected to be generated by applying the enacted combined Canadian federal and provincial statutory tax rate to earnings before corporate taxes. The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

	Quarter Ended June 30		Year-to-Date June 30	
($ millions, except as noted)	**2011**	2010	**2011**	2010
Combined Canadian federal and provincial statutory income tax rate	**30.5%**	32.0%	**30.5%**	32.0%
Statutory income tax rate applied to earnings before corporate taxes	**26**	26	**73**	69
Preference share dividends	**2**	2	**3**	3
Difference between Canadian statutory rate and rates applicable to foreign subsidiaries	**(6)**	(5)	**(8)**	(7)
Difference in Canadian provincial statutory rates applicable to subsidiaries in different Canadian jurisdictions	**1**	(2)	**(5)**	(6)
Items capitalized for accounting purposes but expensed for income tax purposes	**(12)**	(8)	**(28)**	(20)
Difference between capital cost allowance and amounts claimed for accounting purposes	**3**	1	**6**	1
Other	**1**	1	**4**	3
Corporate taxes	**15**	15	**45**	43
Effective tax rate	**17.9%**	18.5%	**18.8%**	19.9%

As at June 30, 2011, the Corporation had approximately $88 million (December 31, 2010 - $95 million) in non-capital and capital loss carryforwards, of which $18 million (December 31, 2010 - $18 million) has not been recognized in the consolidated financial statements. The non-capital loss carryforwards expire between 2014 and 2031.

16. SEGMENTED INFORMATION

Information by reportable segment is as follows:

	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
Quarter Ended June 30, 2011 *($ millions)*	**FortisBC Energy Companies - Canadian**	Fortis Alberta	FortisBC Electric	Newfoundland Power	Other Canadian	**Total Electric Canadian**	**Electric Caribbean [1]**	**Fortis Generation [2]**	**Fortis Properties**	**Corporate and Other**	**Inter-segment eliminations**	**Consolidated**
Revenue	**320**	104	64	133	78	**379**	**87**	**7**	**60**	**8**	**(11)**	**850**
Energy supply costs	**170**	-	11	80	47	**138**	**53**	**1**	**-**	**-**	**(4)**	**358**
Operating expenses	**74**	36	21	17	11	**85**	**11**	**1**	**40**	**3**	**(1)**	**213**
Amortization	**27**	33	12	11	6	**62**	**8**	**1**	**4**	**1**	**-**	**103**
Operating income	**49**	35	20	25	14	**94**	**15**	**4**	**16**	**4**	**(6)**	**176**
Finance charges	**30**	16	9	9	5	**39**	**4**	**1**	**6**	**18**	**(6)**	**92**
Corporate tax expense (recovery)	**4**	-	2	5	3	**10**	**1**	**1**	**3**	**(4)**	**-**	**15**
Net earnings (loss)	**15**	19	9	11	6	**45**	**10**	**2**	**7**	**(10)**	**-**	**69**
Non-controlling interests	**-**	-	-	-	-	**-**	**3**	**-**	**-**	**-**	**-**	**3**
Preference share dividends	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**8**	**-**	**8**
Net earnings (loss) attributable to common equity shareholders	**15**	19	9	11	6	**45**	**7**	**2**	**7**	**(18)**	**-**	**58**
Goodwill	**908**	227	221	-	63	**511**	**129**	**-**	**-**	**-**	**-**	**1,548**
Identifiable assets	**4,235**	2,239	1,291	1,212	650	**5,392**	**683**	**453**	**580**	**685**	**(399)**	**11,629**
Total assets	**5,143**	2,466	1,512	1,212	713	**5,903**	**812**	**453**	**580**	**685**	**(399)**	**13,177**
Gross capital expenditures [3]	**65**	86	23	17	11	**137**	**19**	**59**	**6**	**-**	**-**	**286**
Quarter Ended June 30, 2010 *($ millions)*												
Revenue	**336**	92	59	126	75	**352**	**83**	**8**	**60**	**9**	**(13)**	**835**
Energy supply costs	**191**	-	13	75	46	**134**	**47**	**1**	**-**	**-**	**(6)**	**367**
Operating expenses	**65**	36	19	15	11	**81**	**11**	**2**	**39**	**6**	**(2)**	**202**
Amortization	**28**	25	11	12	6	**54**	**9**	**1**	**4**	**1**	**-**	**97**
Operating income	**52**	31	16	24	12	**83**	**16**	**4**	**17**	**2**	**(5)**	**169**
Finance charges	**29**	14	8	9	5	**36**	**4**	**-**	**6**	**18**	**(5)**	**88**
Corporate tax expense (recovery)	**6**	-	-	4	3	**7**	**2**	**1**	**3**	**(4)**	**-**	**15**
Net earnings (loss)	**17**	17	8	11	4	**40**	**10**	**3**	**8**	**(12)**	**-**	**66**
Non-controlling interests	**-**	-	-	-	-	**-**	**3**	**-**	**-**	**-**	**-**	**3**
Preference share dividends	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**8**	**-**	**8**
Net earnings (loss) attributable to common equity shareholders	**17**	17	8	11	4	**40**	**7**	**3**	**8**	**(20)**	**-**	**55**
Goodwill	**908**	227	221	-	63	**511**	**143**	**-**	**-**	**-**	**-**	**1,562**
Identifiable assets	**4,073**	1,977	1,189	1,190	626	**4,982**	**820**	**195**	**581**	**560**	**(444)**	**10,767**
Total assets	**4,981**	2,204	1,410	1,190	689	**5,493**	**963**	**195**	**581**	**560**	**(444)**	**12,329**
Gross capital expenditures [3]	**60**	89	37	19	13	**158**	**19**	**2**	**4**	**1**	**-**	**244**

(1) Reflects the discontinuance of the consolidation method of accounting for the financial results of Belize Electricity from June 20, 2011

(2) Results reflect contribution from the Vaca hydroelectric generating facility in Belize, which was commissioned in March 2010, and the Waneta Partnership, which was established in October 2010.

(3) Relates to cash payments to acquire or construct utility capital assets, including amounts for AESO transmission-related capital projects, income producing properties and intangible assets, as reflected on the consolidated statement of cash flows

16. SEGMENTED INFORMATION (cont'd)

	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
Year-to-Date June 30, 2011 *($ millions)*	**FortisBC Energy Companies - Canadian**	Fortis Alberta	FortisBC Electric	Newfoundland Power	Other Canadian	**Total Electric Canadian**	**Electric Caribbean (1)**	**Fortis Generation (2)**	**Fortis Properties**	**Corporate and Other**	**Inter-segment eliminations**	**Consolidated**
Revenue	**895**	207	148	316	169	**840**	**162**	**14**	**110**	**15**	**(22)**	**2,014**
Energy supply costs	**514**	-	34	214	107	**355**	**99**	**1**	**-**	**-**	**(8)**	**961**
Operating expenses	**151**	71	39	37	23	**170**	**22**	**4**	**77**	**4**	**(3)**	**425**
Amortization	**53**	66	23	21	12	**122**	**17**	**2**	**9**	**3**	**-**	**206**
Operating income	**177**	70	52	44	27	**193**	**24**	**7**	**24**	**8**	**(11)**	**422**
Finance charges	**59**	29	18	18	11	**76**	**9**	**1**	**12**	**37**	**(11)**	**183**
Corporate tax expense (recovery)	**27**	1	6	8	4	**19**	**1**	**1**	**3**	**(6)**	**-**	**45**
Net earnings (loss)	**91**	40	28	18	12	**98**	**14**	**5**	**9**	**(23)**	**-**	**194**
Non-controlling interests	**-**	-	-	-	-	**-**	**4**	**-**	**-**	**-**	**-**	**4**
Preference share dividends	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**15**	**-**	**15**
Net earnings (loss) attributable to common equity shareholders	**91**	40	28	18	12	**98**	**10**	**5**	**9**	**(38)**	**-**	**175**
Goodwill	**908**	227	221	-	63	**511**	**129**	**-**	**-**	**-**	**-**	**1,548**
Identifiable assets	**4,235**	2,239	1,291	1,212	650	**5,392**	**683**	**453**	**580**	**685**	**(399)**	**11,629**
Total assets	**5,143**	2,466	1,512	1,212	713	**5,903**	**812**	**453**	**580**	**685**	**(399)**	**13,177**
Gross capital expenditures (3)	**114**	171	53	31	19	**274**	**40**	**82**	**9**	**-**	**-**	**519**

Year-to-Date June 30, 2010 *($ millions)*												
Revenue	**862**	180	131	304	157	**772**	**159**	**13**	**109**	**15**	**(22)**	**1,908**
Energy supply costs	**496**	-	34	206	99	**339**	**92**	**1**	**-**	**-**	**(9)**	**919**
Operating expenses	**135**	71	36	31	22	**160**	**23**	**4**	**75**	**10**	**(3)**	**404**
Amortization	**55**	49	21	23	11	**104**	**18**	**2**	**8**	**4**	**-**	**191**
Operating income	**176**	60	40	44	25	**169**	**26**	**6**	**26**	**1**	**(10)**	**394**
Finance charges	**56**	28	15	18	12	**73**	**9**	**-**	**12**	**38**	**(10)**	**178**
Corporate tax expense (recovery)	**30**	-	3	8	4	**15**	**2**	**1**	**4**	**(9)**	**-**	**43**
Net earnings (loss)	**90**	32	22	18	9	**81**	**15**	**5**	**10**	**(28)**	**-**	**173**
Non-controlling interests	**-**	-	-	-	-	**-**	**4**	**-**	**-**	**-**	**-**	**4**
Preference share dividends	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**14**	**-**	**14**
Net earnings (loss) attributable to common equity shareholders	**90**	32	22	18	9	**81**	**11**	**5**	**10**	**(42)**	**-**	**155**
Goodwill	**908**	227	221	-	63	**511**	**143**	**-**	**-**	**-**	**-**	**1,562**
Identifiable assets	**4,073**	1,977	1,189	1,190	626	**4,982**	**820**	**195**	**581**	**560**	**(444)**	**10,767**
Total assets	**4,981**	2,204	1,410	1,190	689	**5,493**	**963**	**195**	**581**	**560**	**(444)**	**12,329**
Gross capital expenditures (3)	**110**	153	63	36	21	**273**	**36**	**3**	**9**	**1**	**-**	**432**

(1) Reflects the discontinuance of the consolidation method of accounting for the financial results of Belize Electricity from June 20, 2011

(2) Results reflect contribution from the Vaca hydroelectric generating facility in Belize, which was commissioned in March 2010, and the Waneta Partnership, which was established in October 2010.

(3) Relates to cash payments to acquire or construct utility capital assets, including amounts for AESO transmission-related capital projects, income producing properties and intangible assets, as reflected on the consolidated statement of cash flows

16. SEGMENTED INFORMATION (cont'd)

Inter-segment transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant inter-segment transactions primarily related to: (i) the sale of energy from Fortis Generation to Belize Electricity, up to June 20, 2011, and FortisOntario; (ii) electricity sales from Newfoundland Power to Fortis Properties; and (iii) finance charges on inter-segment borrowings. The significant inter-segment transactions for the three and six months ended June 30, 2011 and 2010 were as follows:

Significant Inter-Segment Transactions	**Quarter Ended June 30**		**Year-to-Date June 30**	
($ millions)	**2011**	2010	**2011**	2010
Sales from Fortis Generation to Regulated Electric Utilities - Caribbean	**3**	5	**7**	8
Sales from Fortis Generation to Other Canadian Electric Utilities	**1**	1	**1**	1
Sales from Newfoundland Power to Fortis Properties	**1**	1	**2**	2
Inter-segment finance charges on borrowings from:				
Corporate to Regulated Electric Utilities - Canadian	**1**	-	**1**	-
Corporate to Regulated Electric Utilities - Caribbean	**1**	1	**2**	2
Corporate to Fortis Generation	**-**	1	**1**	2
Corporate to Fortis Properties	**3**	3	**6**	5

The significant inter-segment asset balances were as follows:

	As at June 30	
($ millions)	**2011**	2010
Inter-segment borrowings from:		
Corporate to Regulated Electric Utilities - Canadian	**50**	75
Corporate to Regulated Electric Utilities - Caribbean	**68**	59
Corporate to Fortis Generation	**50**	60
Corporate to Fortis Properties	**225**	232
Other inter-segment assets	**6**	18
Total inter-segment eliminations	**399**	444

17. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

	Quarter Ended June 30		**Year-to-Date June 30**	
($ millions)	**2011**	2010	**2011**	2010
Interest paid	**100**	97	**181**	178
Income taxes paid	**21**	13	**45**	37

18. CAPITAL MANAGEMENT

The Corporation's principal businesses of regulated gas and electricity distribution require ongoing access to capital to allow the utilities to fund the maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. Fortis generally finances a significant portion of acquisitions at the corporate level with proceeds from common share, preference share and long-term debt issues. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 40% equity, including preference shares, and 60% debt, as well as investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in the utilities' customer rates.

18. CAPITAL MANAGEMENT (cont'd)

The consolidated capital structure of Fortis is presented in the following table.

	As at			
	June 30, 2011		December 31, 2010	
	($ millions)	***(%)***	*($ millions)*	*(%)*
Total debt and capital lease obligations (net of cash) [(1)]	**5,559**	**54.5**	5,914	58.4
Preference shares [(2)]	**912**	**8.9**	912	9.0
Common shareholders' equity	**3,738**	**36.6**	3,305	32.6
Total [(3)]	**10,209**	**100.0**	10,131	100.0

(1) Includes long-term debt and capital lease obligations, including current portion, and short-term borrowings, net of cash
(2) Includes preference shares classified as both long-term liabilities and equity
(3) Excludes amounts related to non-controlling interests

Certain of the Corporation's long-term debt obligations have covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 70% of the Corporation's consolidated capital structure, as defined by the long-term debt agreements. In addition, one of the Corporation's long-term debt obligations contains a covenant which provides that Fortis shall not declare or pay any dividends, other than stock dividends or cumulative preferred dividends on preference shares not issued as stock dividends, or make any other distribution on its shares or redeem any of its shares or prepay subordinated debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75% of its total consolidated capitalization.

As at June 30, 2011, the Corporation and its subsidiaries, except for the Exploits River Hydro Partnership ("Exploits Partnership"), as described below, were in compliance with their debt covenants.

As the hydroelectric assets and water rights of the Exploits Partnership had been provided as security for the Exploits Partnership term loan, the expropriation of such assets and rights by the Government of Newfoundland and Labrador constituted an event of default under the loan. The term loan is without recourse to Fortis and was approximately $57 million as at June 30, 2011 (December 31, 2010 - $58 million). The lenders of the term loan have not demanded accelerated repayment. The scheduled repayments under the term loan are being made by Nalcor Energy, a Crown corporation, acting as agent for the Government of Newfoundland and Labrador with respect to expropriation matters. For further information refer to Note 30 to the Corporation's 2010 annual audited consolidated financial statements.

The Corporation's credit ratings and consolidated credit facilities are discussed further under "Liquidity Risk" in Note 20.

19. FINANCIAL INSTRUMENTS

Fair Values

There has been no change during the six months ended June 30, 2011 in the designation of the Corporation's financial instruments from that disclosed in the Corporation's 2010 annual audited consolidated financial statements.

The carrying values of the Corporation's consolidated financial instruments approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments, except as noted in the following table.

19. FINANCIAL INSTRUMENTS (cont'd)

	As at			
	June 30, 2011		December 31, 2010	
	Carrying	**Estimated**	Carrying	Estimated
($ millions)	**Value**	**Fair Value**	Value	Fair Value
Waneta Partnership promissory note [(1) (2)]	**43**	**41**	42	40
Long-term debt, including current portion [(3) (4)]	**5,700**	**6,427**	5,669	6,431
Preference shares, classified as debt [(3) (5)]	**320**	**346**	320	344

(1) Included in other long-term liabilities on the consolidated balance sheet
(2) Carrying value is a discounted present value.
(3) Carrying value is measured at amortized cost using the effective interest rate method.
(4) Carrying value as at June 30, 2011 excludes unamortized deferred financing costs of $41 million (December 31, 2010 - $42 million) and capital lease obligations of $41 million (December 31, 2010 - $38 million).
(5) Preference shares classified as equity do not meet the definition of a financial instrument; however, the estimated fair value of the Corporation's $592 million preference shares classified as equity was $612 million as at June 30, 2011 (December 31, 2010 – $615 million).

Excluded from the above table is the $112 million asset as at June 30, 2011 related to the Corporation's previous investment in Belize Electricity. The fair value of this financial asset is not determinable at this time.

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, as is the case with the Waneta Expansion Limited Partnership promissory note, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a market credit risk premium equal to that of issuers of similar credit quality. Since, the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs. The fair value of the Corporation's preference shares is determined using quoted market prices.

From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and fuel and natural gas prices through the use of derivative financial instruments. The Corporation and its subsidiaries do not hold or issue derivative financial instruments for trading purposes. The following table summarizes the valuation of the Corporation's consolidated derivative financial instruments.

	As at					
	June 30, 2011				December 31, 2010	
	Term to	**Number**	**Carrying**	**Estimated**	Carrying	Estimated
	Maturity	**of**	**Value**	**Fair Value**	Value	Fair Value
Liability	***(years)***	**Contracts**	***($ millions)***	***($ millions)***	*($ millions)*	*($ millions)*
Foreign exchange forward contracts [(1) (2)]	**< 1**	**2**	**-**	**-**	-	-
Fuel option contracts [(1) (2)]	**< 1**	**2**	**(1)**	**(1)**	-	-
Natural gas derivatives: [(1) (2)]						
Swaps and options	**Up to 4**	**183**	**(117)**	**(117)**	(162)	(162)
Gas purchase contract premiums	**Up to 3**	**50**	**(3)**	**(3)**	(5)	(5)

(1) The fair value measurements are Level 2, based on the three levels that distinguish the level of pricing observability utilized in measuring fair value.
(2) The fair values of the derivatives were recorded in accounts payable as at June 30, 2011 and as at December 31, 2010.

The fair values of the Corporation's financial instruments, including derivatives, reflect point-in-time estimates based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows.

20. FINANCIAL RISK MANAGEMENT

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit Risk	Risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument.
Liquidity Risk	Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.
Market Risk	Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices. The Corporation is exposed to foreign exchange risk, interest rate risk and commodity price risk.

Credit Risk

For cash and cash equivalents, trade and other accounts receivable, and other long-term receivables, the Corporation's credit risk is limited to the carrying value on the consolidated balance sheet. The Corporation generally has a large and diversified customer base, which minimizes the concentration of credit risk. The Corporation and its subsidiaries have various policies to minimize credit risk, which include requiring customer deposits, prepayments and/or credit checks for certain customers and performing disconnections and/or using third-party collection agencies for overdue accounts.

FortisAlberta has a concentration of credit risk as a result of its distribution service billings being to a relatively small group of retailers. As at June 30, 2011, its gross credit risk exposure was approximately $133 million, representing the projected value of retailer billings over a 60-day period. The Company has reduced its exposure to approximately $8 million by obtaining from the retailers either a cash deposit, bond, letter of credit or an investment-grade credit rating from a major rating agency, or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating.

The FortisBC Energy companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments. To help mitigate credit risk, the FortisBC Energy companies deal with high credit-quality institutions in accordance with established credit-approval practices. The counterparties with which the FortisBC Energy companies have significant transactions are A-rated entities or better. The FortisBC Energy companies use netting arrangements to reduce credit risk and net settle payments with counterparties where net settlement provisions exist.

The aging analysis of the Corporation's consolidated trade and other accounts receivable, net of an allowance for doubtful accounts of $16 million as at June 30, 2011 (March 31, 2011 - $18 million; December 31, 2010 - $16 million; June 30, 2010 - $17 million) was as follows:

	As at			
($ millions)	**June 30, 2011**	March 31, 2011	December 31, 2010	June 30, 2010
Not past due	**488**	601	584	442
Past due 0-30 days	**67**	76	56	49
Past due 31-60 days	**20**	15	9	14
Past due 61 days and over	**14**	8	6	11
	589	700	655	516

As at June 30, 2011, other long-term receivables of $14 million (included in other assets) will be received over the next five years and thereafter, with $3 million expected to be received over years 2 and 3, $1 million over years 4 and 5 and $10 million due after 5 years.

20. FINANCIAL RISK MANAGEMENT (cont'd)

Liquidity Risk

The Corporation's consolidated financial position could be adversely affected if it, or one of its subsidiaries, fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the consolidated results of operations and financial position of the Corporation and its subsidiaries, conditions in capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To help mitigate liquidity risk, the Corporation and its larger regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements.

The Corporation's committed credit facility is available for interim financing of acquisitions and for general corporate purposes. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends. As at June 30, 2011, average annual consolidated long-term debt maturities and repayments over the next five years are expected to be approximately $260 million. The combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

As at June 30, 2011, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.1 billion, of which $1.5 billion was unused. The credit facilities are syndicated almost entirely with the seven largest Canadian banks, with no one bank holding more than 25% of these facilities.

The following table outlines the credit facilities of the Corporation and its subsidiaries.

				As at	
($ millions)	Corporate and Other	Regulated Utilities	Fortis Properties	**June 30, 2011**	December 31, 2010
Total credit facilities	645	1,436	13	**2,094**	2,109
Credit facilities utilized:					
Short-term borrowings	-	(154)	(3)	**(157)**	(358)
Long-term debt (Note 9) [(1)]	(191)	(101)	-	**(292)**	(218)
Letters of credit outstanding	(1)	(120)	-	**(121)**	(124)
Credit facilities unused	453	1,061	10	**1,524**	1,409

[(1)] As at June 30, 2011, credit facility borrowings classified as long-term included $246 million (December 31, 2010 - $16 million) that was included in current installments of long-term debt and capital lease obligations on the consolidated balance sheet.

As at June 30, 2011 and December 31, 2010, certain borrowings under the Corporation's and subsidiaries' credit facilities were classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

In February 2011 Maritime Electric renewed its unsecured committed revolving credit facility, which matures annually in March. The unsecured committed revolving credit facility was reduced from $60 million to $50 million.

In April 2011 FortisBC Electric renegotiated and amended its credit facility agreement resulting in an extension to the maturity of the Company's $150 million unsecured committed revolving credit facility with $100 million now maturing in May 2014 and $50 million now maturing in May 2012.

20. FINANCIAL RISK MANAGEMENT (cont'd)

Liquidity Risk (cont'd)

In April 2011 FHI extended the maturity date of its $30 million unsecured committed revolving credit facility to May 2012.

In June 2011 Newfoundland Power renegotiated and amended its $100 million unsecured committed credit facility obtaining an extension to the maturity of the facility to August 2015 from August 2013. The amended credit facility agreement reflects a decrease in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

The Corporation and its currently rated utilities target investment-grade credit ratings to maintain capital market access at reasonable interest rates. As at June 30, 2011, the Corporation's credit ratings were as follows:

Standard & Poor's	A- (long-term corporate and unsecured debt credit rating)
DBRS	A(low) (unsecured debt credit rating)

The credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level, the Corporation's reasonable credit metrics and its demonstrated ability and continued focus on acquiring and integrating stable regulated utility businesses financed on a conservative basis.

The following is an analysis of the contractual maturities of the Corporation's consolidated financial liabilities as at June 30, 2011.

Financial Liabilities *($ millions)*	Due within 1 year	Due in years 2 and 3	Due in years 4 and 5	Due after 5 years	**Total**
Short-term borrowings	157	-	-	-	**157**
Trade and other accounts payable	726	-	-	-	**726**
Natural gas derivatives [(1)]	70	38	3	-	**111**
Fuel option contracts [(2)]	1	-	-	-	**1**
Foreign exchange forward contracts [(3)]	5	-	-	-	**5**
Dividends payable	57	-	-	-	**57**
Customer deposits [(4)]	-	3	1	2	**6**
Waneta Partnership promissory note [(5)]	-	-	-	72	**72**
Long-term debt, including current portion [(6)]	318	289	695	4,398	**5,700**
Interest obligations on long-term debt	344	672	592	4,901	**6,509**
Preference shares, classified as debt	-	123	-	197	**320**
Dividend obligations on preference shares, classified as finance charges	17	28	20	2	**67**
	1,695	1,153	1,311	9,572	**13,731**

(1) Amounts disclosed are on a gross cash flow basis. The derivatives were recorded in accounts payable at fair value as at June 30, 2011 at $120 million.
(2) Amounts disclosed are on a gross cash flow basis. The contracts were recorded in accounts payable at fair value as at June 30, 2011 at $1 million.
(3) Amounts disclosed are on a gross cash flow basis. The contracts were recorded in accounts payable at fair value as at June 30, 2011 at less than $1 million.
(4) Customer deposits were recorded in other long-term liabilities as at June 30, 2011.
(5) Amounts disclosed are on a gross cash flow basis. The promissory note was recorded in other long-term liabilities at present value as at June 30, 2011 at $43 million.
(6) Excludes deferred debt financing costs of $41 million and capital lease obligations of $41 million

20. FINANCIAL RISK MANAGEMENT (cont'd)

Market Risk

Foreign Exchange Risk
The Corporation's earnings from, and net investments in, self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. Foreign exchange gains and losses on the translation of US dollar-denominated interest expense partially offsets the foreign exchange losses and gains on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of Caribbean Utilities, Fortis Turks and Caicos, FortisUS Energy Corporation and Belize Electric Company Limited is the US dollar.

As at June 30, 2011, US$529 million of the US$594 million corporately issued long-term debt (December 31, 2010 - US$590 million of US$590 million) had been designated as an effective hedge of the Corporation's net investments in self-sustaining foreign subsidiaries. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar borrowings designated as effective hedges are recognized in other comprehensive income and help offset unrealized foreign currency exchange gains and losses on the net investments in self-sustaining foreign subsidiaries, which are also recognized in other comprehensive income.

Effective June 20, 2011, the Corporation's asset associated with Belize Electricity (Note 8) does not qualify for hedge accounting as Belize Electricity is no longer a self-sustaining foreign subsidiary of Fortis. As a result, approximately US$65 million of corporately issued debt that previously hedged the former investment in Belize Electricity is no longer an effective hedge. Effective June 20, 2011, foreign exchange gains and losses on the translation of the asset associated with Belize Electricity and the corporately issued US dollar denominated debt that previously qualified as a hedge of the investment are required to be recognized in earnings. This change in accounting treatment is not expected to have a material impact on consolidated earnings of Fortis. As at June 30, 2011, all of the Corporation's net investments in self-sustaining foreign subsidiaries were hedged (December 31, 2010 - 99%).

FEI and FEVI's US dollar payments under contracts for the implementation of a customer information system and the construction of a liquefied natural gas storage facility, respectively, expose the utilities to fluctuations in the US dollar-to-Canadian dollar exchange rate. FEI and FEVI have entered into foreign exchange forward contracts to hedge this exposure and any increase or decrease in the fair value of the foreign exchange forward contracts is deferred for recovery from, or refund to, customers in future rates, subject to regulatory approval.

Interest Rate Risk
The Corporation and its subsidiaries are exposed to interest rate risk associated with short-term borrowings and floating-rate debt. The Corporation and its subsidiaries may enter into interest rate swap agreements to help reduce this risk.

The FortisBC Energy companies and FortisBC Electric have regulatory approval to defer any increase or decrease in interest expense resulting from fluctuations in interest rates associated with variable-rate debt for recovery from, or refund to, customers in future rates.

Commodity Price Risk
The FortisBC Energy companies are exposed to commodity price risk associated with changes in the market price of natural gas. This risk is minimized from time to time by entering into natural gas derivatives that effectively fix the price of natural gas purchases. The natural gas derivatives are recognized on the consolidated balance sheet at fair value and any change in the fair value is deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates.

20. FINANCIAL RISK MANAGEMENT (cont'd)

Market Risk (cont'd)

Commodity Price Risk (cont'd)
The price risk-management strategy of the FortisBC Energy companies aims to improve the likelihood that natural gas prices remain competitive with electricity rates, temper gas price volatility on customer rates and reduce the risk of regional price discrepancies. On an annual basis, FEI and FEVI each file a Price Risk-Management Plan ("PRMP") that seeks approval for the natural gas commodity hedging plan for the next three years for FEI and the next five years for FEVI. During the third quarter of 2010, the BCUC denied the PRMP application filed by the FortisBC Energy companies earlier in 2010 and directed the Companies to undertake a review of the primary objectives of the PRMP. In January 2011 the FortisBC Energy companies reviewed the PRMP objectives with the BCUC related to their gas commodity hedging plan and FEI submitted a 2011–2014 PRMP. In June 2011 FEVI filed a 2012-2013 hedging request application. In July 2011 the BCUC denied FEI's 2011-2014 PRMP with the exception of certain elements related to basis swaps. The existing hedging contracts are expected to continue in effect through to their maturity and the gas utilities' ability to fully recover the commodity cost of gas in customer rates remains unchanged.

Caribbean Utilities is exposed to commodity price risk associated with changes in the market price of fuel. The Company has a Fuel Price Volatility Management Program, as approved by the regulator, to reduce the impact of volatility of fuel prices on customer rates. The derivatives are recognized on the consolidated balance sheet at fair value and any change in the fair value is deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates. In April 2011 Caribbean Utilities entered into two fuel option contracts.

21. CONTINGENT LIABILITIES AND COMMITMENTS

Contingent Liabilities

The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with ordinary course business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's consolidated financial position or results of operations. There were no material changes in the Corporation's contingencies from those disclosed in the Corporation's 2010 annual audited consolidated financial statements.

Commitments

There were no material changes in the nature and amount of the Corporation's commitments from the commitments disclosed in the Corporation's 2010 annual audited consolidated financial statements, except as described below.

As a result of Belize Electricity no longer being consolidated in the Corporation's financial statements effective June 20, 2011, the power purchase obligations associated with Belize Electricity's operations are no longer included in the Corporation's consolidated commitments.

During the six months ended June 30, 2011, the actuarial valuation of the defined benefit pension plans at FortisBC Energy, covering unionized employees, and at FortisBC Electric were completed. As a result of the actuarial valuations and other revised actuarial estimates, the total estimate of consolidated defined benefit pension funding contributions over the next five years, net of payments made year-to-date June 30, 2011, has increased by approximately $45 million from that disclosed in the Corporation's 2010 annual audited consolidated financial statements. The increase in funding contributions is expected to be recovered from customers in future rates.

As at June 30, 2011, $20 million of FEVI government loans were reclassified from utility capital assets to current portion of long-term debt as a result of an expected repayment within one year.

22. SUBSEQUENT EVENTS

On July 11, 2011, the Board of Directors of Central Vermont Public Service Corporation ("CVPS") determined that the unsolicited acquisition proposal from Gaz Métro Limited Partnership was a "Superior Proposal", as that term is defined in the Merger Agreement between Fortis and CVPS announced on May 30, 2011 (the "Merger Agreement") and that CVPS elected to terminate the Merger Agreement in accordance with its terms. Prior to such termination taking effect, the Merger Agreement provided Fortis the right to require CVPS to negotiate with Fortis for at least five business days with respect to any changes to the terms of the Merger Agreement proposed by Fortis. Fortis agreed to waive such right in exchange for the prompt payment by CVPS to Fortis of the US$17.5 million termination fee plus US$2.0 million for expenses as set forth in the Merger Agreement, thereby resulting in the termination of the Merger Agreement. Fortis received the $18.8 million (US$19.5 million) payment on July 12, 2011.

On July 15, 2011, the underwriters of the Corporation's June 2011 $300 million public offering of 9.1 million common shares exercised their over-allotment option and purchased an additional 1.24 million common shares of Fortis for gross proceeds of approximately $41 million.

23. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to comply with current period presentation. The most significant changes related to: (i) a $48 million decrease for the six months ended June 30, 2010 in cash from operating activities associated with changes in non-cash operating working capital and a corresponding decrease in cash used in financing activities associated with dividends on common shares; and (ii) a $13 million and $28 million decrease for the three and six months ended June 30, 2010, respectively, in cash from financing activities associated with the issuance of common shares and a corresponding decrease in cash used in financing activities associated with dividends paid on common shares.

Dates – Dividends* and Earnings

Expected Earnings Release Dates

November 3, 2011	February 9, 2012
May 2, 2012	August 1, 2012

Dividend Record Dates

August 12, 2011	November 14, 2011
February 10, 2012	May 11, 2012

Dividend Payment Dates

September 1, 2011	December 1, 2011
March 1, 2012	June 1, 2012

* *The declaration and payment of dividends are subject to Board of Directors' approval.*

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Share Listings

The Common Shares, First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G and First Preference Shares, Series H of Fortis Inc. are traded on the Toronto Stock Exchange under the symbols FTS, FTS.PR.C, FTS.PR.E, FTS.PR.F, FTS.PR.G and FTS.PR.H, respectively.

Fortis Common Shares ($) Quarter Ended June 30		
	2011	**2010**
High	**33.85**	**29.24**
Low	**30.79**	**21.60**
Close	**32.35**	**27.18**