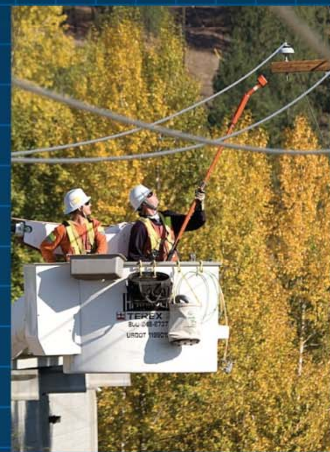
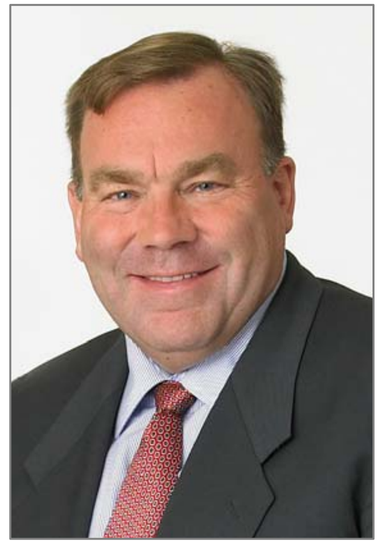
FORTIS INC.

Third Quarter 2010



Dear Shareholder:



Fortis achieved third quarter net earnings attributable to common equity shareholders of $45 million, or $0.26 per common share, up $9 million from earnings of $36 million, or $0.21 per common share, for the third quarter of 2009. Year-to-date net earnings attributable to common equity shareholders were $200 million, or $1.16 per common share, up $19 million from earnings of $181 million, or $1.06 per common share, for the same period last year.

Performance for the quarter was driven by the regulated electric utilities in western Canada and non-regulated hydroelectric generation operations.

Canadian Regulated Electric Utilities contributed earnings of $43 million, up $7 million from the third quarter of 2009, associated with higher contributions from FortisAlberta, FortisBC and Newfoundland Power. The $4 million increase in earnings at FortisAlberta was associated with the higher allowed rate of return on common equity ("ROE"), the higher equity component of total capital structure, growth in electrical infrastructure investment and an increase in customers, partially offset by lower net transmission revenue. Earnings at FortisBC increased $2 million, mainly as a result of the higher allowed ROE and growth in electrical infrastructure investment, partially offset by a weather-related decrease in electricity sales. The approximate $1 million improvement in earnings at Newfoundland Power related to increased electricity sales and growth in electrical infrastructure investment, partially offset by higher operating expenses associated with repairing damage from Hurricane Igor in September 2010.

The Terasen Gas companies incurred a loss of $5 million for the third quarter of 2010 compared to a loss of $3 million for the same quarter last year. The third quarter is normally a period of lower customer demand due to warmer temperatures. The higher loss quarter over quarter largely related to increased operating and maintenance expenses at Terasen Gas Inc. ("TGI") that were approved by the British Columbia Utilities Commission ("BCUC") as part of the recent Negotiated Settlement Agreement. 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.

Caribbean Regulated Electric Utilities contributed $8 million to earnings, up $1 million from the third quarter of 2009, largely driven by the deferral, for future collection in customer rates, of previously expensed business taxes at Belize Electricity.

Non-Regulated Fortis Generation contributed $9 million to earnings, up $5 million from the third quarter of 2009, mainly attributable to increased hydroelectric production in Belize, driven by higher rainfall and the commissioning of the Vaca hydroelectric generating facility in March 2010, and lower finance charges.

In October, Fortis, in partnership with Columbia Power Corporation and Columbia Basin Trust, concluded definitive agreements to construct a 335-megawatt hydroelectric generating facility (the "Waneta Expansion") at an estimated cost of approximately $900 million. The facility is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia. Fortis owns a 51 per cent interest in the Waneta Expansion and will operate and maintain the non-regulated investment when the facility comes into service, which is expected in spring 2015. Construction is anticipated to start in November 2010.

Fortis Properties delivered earnings of $9 million, consistent with earnings for the third quarter of 2009.

Corporate and other expenses were $19 million compared to $17 million for the same quarter last year. The increase in dividends associated with the First Preference Shares, Series H issued in January 2010 was partially offset by lower finance charges.

In October, DBRS upgraded the Corporation's debt credit rating to A(low) from BBB(high). The credit rating upgrade by DBRS was mainly due to the Corporation's low business-risk profile, reasonable credit metrics, significant reduction in external debt at Terasen Inc. and the Corporation's demonstrated ability to acquire and integrate stable utility businesses financed on a conservative basis. In October, DBRS also upgraded the debt credit rating of FortisBC to A(low) from BBB(high).

Consolidated capital expenditures, before customer contributions, were $703 million year to date compared to $763 million for the same period last year.

Cash flow from operating activities was $582 million year to date, up $15 million from $567 million for the same period last year.

Our 2010 capital program is estimated at $1.1 billion, the largest annual capital program ever undertaken by Fortis. Planning is also well underway for utility capital work that will be undertaken in 2011 and beyond to ensure we continue to meet our customers' needs. Over the next five years our capital program, including work related to the Waneta Expansion Project, is expected to approach $5.5 billion, driving growth in earnings and dividends.

Fortis continues to pursue acquisitions to build on this organic growth, focusing on regulated electric and natural gas utilities in the United States and Canada.

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

Interim Management Discussion and Analysis

For the three and nine months ended September 30, 2010
Dated November 5, 2010

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FORWARD-LOOKING STATEMENT

The following analysis 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 nine months ended September 30, 2010 and the Management Discussion and Analysis ("MD&A") and audited consolidated financial statements for the year ended December 31, 2009 included in the Corporation's 2009 Annual Report. This material has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations* relating to MD&As. Financial information in this material 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 the implementation of new and final customer rates at FortisAlberta as a result of the regulatory decision on the 2010 and 2011 revenue requirements application; the expected increase in the total capital cost of the Fraser River South Bank South Arm Rehabilitation project at Terasen Gas Inc.; the expected total capital cost of FortisAlberta's automated meter reading technology project; the expected total capital cost for the construction of the 335-megawatt Waneta hydroelectric generating facility and its expected completion date; expected consolidated gross capital expenditures for 2010 and in total over the five-year period from 2011 through 2015; the expectation that the Corporation's significant capital program should drive growth in earnings and dividends; the expected increase in average annual energy production from the Macal River in Belize by the Vaca hydroelectric generating facility; expected consolidated long-term debt maturities and repayments on average annually over the next five years; the expectation of no material adverse credit rating actions in the near term; expected sources of financing for the subsidiaries' capital expenditure programs; and except for debt at Belize Electricity and Exploits River Hydro Partnership ("Exploits Partnership"), the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants during 2010. 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 continued ability to maintain the gas and electricity systems to ensure their continued performance; no significant decline in capital spending in 2010; 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 continued 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; no material decrease in market energy sales prices; 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; economic conditions; capital resources and liquidity risk; capital project budget overruns and financing risk in the Corporation's non-regulated business; 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 Terasen Gas (Vancouver Island) Inc. franchise; the Government of British Columbia's Energy Plan; environmental risks; insurance coverage risk; loss of licences and permits; loss of service area; market energy sales prices; changes in the current assumptions and expectations associated with the transition to International Financial Reporting Standards; 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 nine months ended September 30, 2010 and for the year ended December 31, 2009.*

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.

COMPANY OVERVIEW AND FINANCIAL HIGHLIGHTS

Fortis is the largest investor-owned distribution utility in Canada, serving approximately 2,100,000 gas and electricity customers. Its regulated holdings include electric utilities in five Canadian provinces and three Caribbean countries and a natural gas utility in British Columbia. Fortis owns and operates non-regulated generation assets 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 September 30, 2010, the Corporation's electricity distribution systems met a combined peak demand of approximately 5,034 megawatts ("MW") and its gas distribution system met a peak day demand of 1,006 terajoules ("TJ"). For additional information on the Corporation's business segments, refer to Note 1 to the Corporation's 2009 annual audited consolidated financial statements.

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 to customers at the lowest reasonable cost and conduct business in an environmentally responsible manner. The Corporation's main business, utility operations, is highly regulated. It is segmented by franchise area and, depending on regulatory requirements, by the nature of the assets.

Fortis has adopted a strategy of profitable growth with earnings per common share as the primary measure of performance. Key financial highlights, including earnings by reportable segment, for the third quarter and year-to-date periods ended September 30, 2010 and September 30, 2009 are provided in the following tables.

Financial Highlights (Unaudited)	Quarter			Year-to-date		
Periods Ended September 30	**2010**	2009	Variance	**2010**	2009	Variance
Revenue *($ millions)*	**720**	665	55	**2,627**	2,623	4
Cash Flow from Operating Activities *($ millions)*	**129**	63	66	**582**	567	15
Net Earnings Attributable to Common Equity Shareholders *($ millions)*	**45**	36	9	**200**	181	19
Basic Earnings per Common Share *($)*	**0.26**	0.21	0.05	**1.16**	1.06	0.10
Diluted Earnings per Common Share *($)*	**0.26**	0.21	0.05	**1.15**	1.05	0.10
Weighted Average Number of Common Shares Outstanding *(millions)*	**173.2**	170.4	2.8	**172.4**	170.0	2.4

Segmented Net Earnings Attributable to Common Equity Shareholders (Unaudited)
Periods Ended September 30

($ millions)	Quarter **2010**	Quarter 2009	Quarter Variance	Year-to-date **2010**	Year-to-date 2009	Year-to-date Variance
Regulated Gas Utilities - Canadian						
Terasen Gas Companies (1)	**(5)**	(3)	(2)	**85**	69	16
Regulated Electric Utilities - Canadian						
FortisAlberta	***19***	*15*	*4*	***51***	*45*	*6*
FortisBC (2)	***11***	*9*	*2*	***33***	*29*	*4*
Newfoundland Power	***8***	*7*	*1*	***26***	*24*	*2*
Other Canadian (3)	***5***	*5*	*-*	***14***	*13*	*1*
	43	36	7	**124**	111	13
Regulated Electric - Caribbean (4)	**8**	7	1	**19**	20	(1)
Non-Regulated - Fortis Generation (5)	**9**	4	5	**14**	14	-
Non-Regulated - Fortis Properties (6)	**9**	9	-	**19**	19	-
Corporate and Other (7)	**(19)**	(17)	(2)	**(61)**	(52)	(9)
Net Earnings Attributable to Common Equity Shareholders	**45**	36	9	**200**	181	19

(1) Comprised of Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGWI")

(2) 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

(3) Includes Maritime Electric and FortisOntario. FortisOntario mainly includes Canadian Niagara Power, Cornwall Electric and, from October 2009, Algoma Power Inc. ("Algoma Power")

(4) Includes Belize Electricity, in which Fortis holds an approximate 70 per cent controlling interest; Caribbean Utilities on Grand Cayman, Cayman Islands, in which Fortis holds an approximate 59 per cent controlling interest; and wholly owned Fortis Turks and Caicos

(5) Includes the financial results of non-regulated assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State, with a combined generating capacity of 139 megawatts ("MW"), mainly hydroelectric. Results reflect contribution from the Vaca hydroelectric generating facility in Belize, from March 2010 when the facility was commissioned. Prior to May 1, 2009, the financial results of Fortis reflected earnings' contribution associated with the Corporation's 75-MW water-right entitlement on the Niagara River in Ontario related to the Rankine hydroelectric generating facility. The water rights expired on April 30, 2009, at the end of a 100-year term. Additionally, prior to February 12, 2009, the financial results of the hydroelectric generation operations in central Newfoundland were consolidated in the financial statements of Fortis. Effective February 12, 2009, the Corporation discontinued the consolidation method of accounting for the generation operations in central Newfoundland due to the Corporation no longer having control over the operations and cash flows, as a result of the expropriation of the assets of the Exploits River Hydro Partnership by the Government of Newfoundland and Labrador. For a further discussion of this matter, refer to the "Critical Accounting Estimates - Contingencies" section of the MD&A for the year ended December 31, 2009.

(6) Fortis Properties owns and operates 21 hotels, comprised of more than 4,100 rooms, in eight Canadian provinces and approximately 2.8 million square feet of commercial office and retail space primarily in Atlantic Canada.

(7) Includes Fortis net corporate expenses, net expenses of non-regulated Terasen Inc. ("Terasen") corporate-related activities and the financial results of Terasen's 30 per cent ownership interest in CustomerWorks Limited Partnership ("CWLP") and of Terasen's non-regulated wholly owned subsidiary Terasen Energy Services Inc. ("TES")

SEGMENTED RESULTS OF OPERATIONS

REGULATED GAS UTILITIES - CANADIAN

TERASEN GAS COMPANIES

Gas Volumes by Major Customer Category (Unaudited)						
Periods Ended September 30		**Quarter**			**Year-to-date**	
(TJ)	**2010**	2009	Variance	**2010**	2009	Variance
Core – Residential and Commercial	**12,342**	12,050	292	**76,600**	82,537	(5,937)
Industrial	**840**	762	78	**3,708**	4,379	(671)
Total Sales Volumes	**13,182**	12,812	370	**80,308**	86,916	(6,608)
Transportation Volumes	**11,383**	10,396	987	**41,963**	43,130	(1,167)
Throughput under Fixed Revenue Contracts	**2,771**	4,601	(1,830)	**10,897**	12,184	(1,287)
Total Gas Volumes	**27,336**	27,809	(473)	**133,168**	142,230	(9,062)

Factors Contributing to Net Negative Quarterly Gas Volumes Variance

Unfavourable
- Lower volumes under fixed revenue contracts, due to a large customer changing its gas supply requirements from peak demand to emergency demand

Favourable
- Higher average gas consumption by residential and commercial customers as a result of cooler temperatures quarter over quarter
- Higher transportation volumes as a result of the favourable impact of improving economic conditions in the third quarter of 2010 in the forestry sector

Factors Contributing to Negative Year-to-Date Gas Volumes Variance

Unfavourable
- Lower average gas consumption by residential and commercial customers as a result of warmer average temperatures in the first quarter of 2010 compared to the same quarter in 2009, partially offset by the impact of cooler temperatures in the third quarter of 2010 compared to the same quarter in 2009
- Lower transportation volumes as a result of warmer average temperatures period over period and the impact of unfavourable economic conditions negatively affecting the forestry sector mainly in the first quarter of 2010
- Lower volumes under fixed revenue contracts, mainly for the reason discussed above for the quarter

Net customer additions were 3,460 year-to-date 2010 compared to 743 for the same period last year. Gross customer additions increased period over period due to increased building activity and customer reconnections were higher period over period due to cooler temperatures in the third quarter of 2010 compared to the same quarter last year.

Because of natural gas consumption patterns, earnings of the Terasen Gas companies are highest in the first and fourth quarters. As a result of seasonality, interim earnings are not indicative of annual earnings.

The Terasen Gas 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 forecasted to set gas rates do not materially affect earnings.

Financial Highlights (Unaudited)						
Periods Ended September 30	**Quarter**			**Year-to-date**		
($ millions)	**2010**	2009	Variance	**2010**	2009	Variance
Revenue	**206**	208	(2)	**1,067**	1,166	(99)
Energy Supply Costs	**90**	98	(8)	**586**	722	(136)
Operating Expenses	**66**	60	6	**201**	189	12
Amortization	**27**	25	2	**81**	76	5
Finance Charges	**28**	30	(2)	**84**	91	(7)
Corporate Tax (Recovery) Expense	**-**	(2)	2	**30**	19	11
Earnings	**(5)**	(3)	(2)	**85**	69	16

Factors Contributing to Net Negative Quarterly Revenue Variance

Unfavourable
- Lower commodity cost of natural gas charged to customers

Favourable
- Higher average gas consumption by residential and commercial customers
- Increased customer delivery rates, effective January 1, 2010, which included: (i) the impact of the increase in the allowed rate of return on common shareholder's equity ("ROE") to 9.50 per cent from 8.47 per cent for Terasen Gas Inc. ("TGI") and to 10.00 per cent for each of Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas Whistler Inc. ("TGWI") from 9.17 per cent and 8.97 per cent, respectively; (ii) the increase in the deemed common equity component of the total capital structure ("equity component") for TGI to 40 per cent from 35 per cent; and (iii) higher forecasted regulatory approved operating expenses and amortization cost

Factors Contributing to Net Negative Year-to-Date Revenue Variance

Unfavourable
- Lower average gas consumption by residential and commercial customers
- Lower commodity cost of natural gas charged to customers

Favourable
- The increase in customer delivery rates, effective January 1, 2010

Factors Contributing to Net Negative Quarterly Earnings Variance

Unfavourable
- Higher operating expenses driven by: (i) increased labour and employee-benefit costs; (ii) new initiatives agreed to in the regulator-approved Negotiated Settlement Agreement ("NSA") related to 2010 and 2011 revenue requirements resulting in higher planned maintenance and operating activities in 2010 compared to 2009; (iii) the expensing of asset removal costs to operating expenses, effective January 1, 2010, as a result of the NSA; and (iv) lower capitalized overhead costs, due to a reduction in the capitalization rate, also as a result of the NSA. The asset removal costs and higher expensed overhead costs were approved for collection in current customer delivery rates. Prior to 2010, asset removal costs were recorded against accumulated amortization.
- Increased amortization cost due to higher amortization rates period over period and continued investment in utility capital assets. The new amortization rates were determined and approved by the regulator upon review of a current depreciation study. The increase in amortization is being collected in current customer delivery rates.
- A higher effective corporate income tax rate period over period, mainly due to lower deductions from income for income tax purposes compared to accounting purposes in 2010 compared to 2009

Favourable

- The increase in customer delivery rates, effective January 1, 2010
- The reversal of approximately $5 million ($4 million after tax) of operating expenses in the third quarter of 2010 related to 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. During the third quarter of 2010, the Company received approval from the British Columbia Utilities Commission ("BCUC") to collect most of the additional costs in future customer rates.
- Lower finance charges due to lower average credit facility borrowings period over period

Factors Contributing to Net Positive Year-to-Date Earnings Variance

Year-to-date 2010, earnings at the Terasen Gas companies were favourably impacted by the same factors as discussed above for the quarter, partially offset by the same unfavourable factors also as discussed above for the quarter.

For a discussion of the nature of regulation and material regulatory decisions and applications pertaining to the Terasen Gas companies, refer to the "Regulatory Highlights" section of this MD&A.

REGULATED ELECTRIC UTILITIES - CANADIAN

FORTISALBERTA

Financial Highlights (Unaudited)	**Quarter**			**Year-to-date**		
Periods Ended September 30	**2010**	2009	Variance	**2010**	2009	Variance
Energy Deliveries *(gigawatt hours ("GWh"))*	**3,778**	3,819	(41)	**11,611**	11,736	(125)
($ millions)						
Revenue	**109**	84	25	**289**	245	44
Operating Expenses	**33**	33	-	**104**	98	6
Amortization	**45**	25	20	**94**	70	24
Finance Charges	**12**	12	-	**40**	36	4
Corporate Tax Recovery	**-**	(1)	1	**-**	(4)	4
Earnings	**19**	15	4	**51**	45	6

Factors Contributing to Net Negative Quarterly Energy Deliveries Variance

Unfavourable

- Decreased energy deliveries to farm and irrigation, and other industrial customers, mainly due to lower average consumption resulting from relatively milder temperatures. Energy deliveries to irrigation customers were also negatively impacted by continued heavy rainfall during the third quarter of 2010.

Favourable

- Increased energy deliveries associated with an increase in the number of residential and commercial customers

Factors Contributing to Net Negative Year-to-Date Energy Deliveries Variance

Unfavourable

- The same factors as discussed above for the quarter

Favourable

- Increased energy deliveries associated with an increase in the number of residential, commercial and oil and gas customers

As at September 30, 2010, the total number of customers at FortisAlberta increased 11,000 year over year.

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. Revenues are a function of numerous variables, many of which are independent of actual energy deliveries.

Factors Contributing to Net Positive Quarterly and Year-to-Date Revenue Variance

Favourable

- An approximate $22 million and $27 million electricity rate revenue accrual for the quarter and year to date, respectively, associated with the impact of the 2010-2011 regulatory rate decision. The rate revenue accrual was primarily associated with regulatory approved increased amortization, operating expenses and finance charges and, therefore, did not have a significant impact on earnings. Approximately $14 million of the accrual in the third quarter related to the first half of 2010.
- An interim 7.5 per cent average increase in base customer electricity distribution rates, effective January 1, 2010
- A rate revenue accrual of approximately $1 million and $3 million for the quarter and year to date, respectively, to reflect an allowed ROE of 9.00 per cent, compared to an interim allowed ROE of 8.51 per cent as reflected in revenue year-to-date 2009 and an increase in the equity component to 41 per cent from 37 per cent as reflected in revenue year-to-date 2009
- Customer growth

Collection of the revenue accruals is expected to begin with new final customer rates and riders, effective January 1, 2011.

Unfavourable

- Lower net transmission revenue. Effective January 1, 2010, as a result of the 2010-2011 regulatory rate decision, the impact of volume risk on transmission costs is deferred to be recovered from, or refunded to, customers in future rates
- Lower miscellaneous revenue

Factors Contributing to Net Positive Quarterly and Year-to-Date Earnings Variance

Favourable

- The increase in electricity distribution rate revenue related to the increase in the allowed ROE and equity component, ongoing investment in electrical infrastructure, customer growth and higher forecasted regulatory approved expenses

Unfavourable

- Increased amortization cost associated with higher overall amortization rates, as approved in the 2010-2011 regulatory rate decision, and continued investment in utility capital assets, partially offset by the impact of the commencement, in 2010, of the capitalization of amortization for vehicles and tools used in the construction of other assets, as approved by the regulator
- Increased operating expenses year to date, mainly due to higher labour costs and general operating expenses, partially offset by lower contracted labour costs
- Increased finance charges year to date, due to higher debt levels in support of the Company's significant capital expenditure program, partially offset by lower average credit facility borrowings, increased capitalized allowance for funds used during construction and the impact of lower interest rates on the credit facility borrowings
- Lower net transmission revenue for the reason discussed above
- Lower corporate tax recovery in 2010, due to lower future income tax recoveries associated with changes in net customer deferrals subject to future income tax recoveries and a favourable adjustment to current income taxes of approximately $2 million during the second quarter of 2009

For a discussion of the nature of regulation and material regulatory decisions and applications pertaining to FortisAlberta, refer to the "Regulatory Highlights" section of this MD&A.

FORTISBC

Financial Highlights (Unaudited)	Quarter			Year-to-date		
Periods Ended September 30	**2010**	2009	Variance	**2010**	2009	Variance
Electricity Sales *(GWh)*	**709**	720	(11)	**2,199**	2,298	(99)
($ millions)						
Revenue	**62**	57	5	**193**	184	9
Energy Supply Costs	**16**	15	1	**50**	50	-
Operating Expenses	**17**	16	1	**53**	51	2
Amortization	**10**	9	1	**31**	28	3
Finance Charges	**7**	8	(1)	**23**	23	-
Corporate Taxes	**1**	-	1	**3**	3	-
Earnings	**11**	9	2	**33**	29	4

Factors Contributing to Net Negative Quarterly and Year-to-Date Electricity Sales Variance

Unfavourable
- Lower average consumption primarily due to unfavourable weather conditions

Favourable
- Residential and general service customer growth
- Increased industrial customer loads

Factors Contributing to Net Positive Quarterly and Year-to-Date Revenue Variance

Favourable
- A 6.0 per cent increase in customer electricity rates, effective January 1, 2010, reflecting an increase in the allowed ROE to 9.90 per cent for 2010, up from 8.87 per cent for 2009, and ongoing investment in electrical infrastructure
- A 2.9 per cent interim, refundable increase in customer electricity rates, effective September 1, 2010, as a result of the flow through to customers of increased power purchase costs charged by BC Hydro
- Increased performance-based rate-setting ("PBR") incentive adjustments receivable from customers
- Higher revenue contribution from non-regulated operating, maintenance and management services year to date

Unfavourable
- The 1.5 per cent and 4.3 per cent decrease in electricity sales for the quarter and year to date, respectively, compared to the same periods last year

Factors Contributing to Net Positive Quarterly Earnings Variance

Favourable
- The increases in customer electricity rates, effective January 1, 2010 and September 1, 2010
- Increased PBR incentive adjustments
- Lower finance charges, primarily due to an increase in capitalized interest and lower bank fees, partially offset by higher debt levels in support of the Company's capital expenditure program and higher interest rates

Unfavourable
- Higher energy supply costs associated with a higher proportion of purchased power versus energy generated from Company-owned hydroelectric generating facilities and the impact of higher average prices for purchased power, partially offset by the impact of decreased electricity sales
- Increased amortization cost associated with continued investment in utility capital assets
- Decreased electricity sales

Factors Contributing to Net Positive Year-to-Date Earnings Variance

Favourable
- The same factors as discussed above for the quarter
- Slightly lower energy supply costs associated with decreased electricity sales and a lower proportion of purchased power versus energy generated from Company-owned hydroelectric generating facilities, offset by the impact of higher average prices for purchased power

Unfavourable
- Increased property taxes and water fees, partially offset by a decrease in certain other operating expenses due to the timing of operating and maintenance projects in 2010 and their related expenditures
- Increased amortization cost, for the reason discussed above for the quarter
- Decreased electricity sales

For a discussion of the nature of regulation and material regulatory decisions and applications pertaining to FortisBC, refer to the "Regulatory Highlights" section of this MD&A.

NEWFOUNDLAND POWER

Financial Highlights (Unaudited)		**Quarter**			**Year-to-date**	
Periods Ended September 30	**2010**	2009	Variance	**2010**	2009	Variance
Electricity Sales *(GWh)*	**916**	885	31	**3,931**	3,825	106
($ millions)						
Revenue	**99**	93	6	**403**	381	22
Energy Supply Costs	**50**	50	-	**256**	246	10
Operating Expenses	**16**	12	4	**47**	39	8
Amortization	**12**	11	1	**35**	34	1
Finance Charges	**9**	9	-	**27**	26	1
Corporate Taxes	**4**	4	-	**12**	12	-
Earnings	**8**	7	1	**26**	24	2

Factors Contributing to Positive Quarterly and Year-to-Date Electricity Sales Variance

Favourable
- Customer growth and higher average consumption

Factors Contributing to Positive Quarterly and Year-to-Date Revenue Variance

Favourable
- An average 3.5 per cent increase in customer electricity rates, effective January 1, 2010, reflecting an increase in the allowed ROE to 9.00 per cent for 2010, up from 8.95 per cent for 2009, ongoing investment in electrical infrastructure and higher forecasted regulatory approved expenses, including pension costs
- A 3.5 per cent and 2.8 per cent increase in electricity sales for the quarter and year to date, respectively, compared to the same periods last year

Factors Contributing to Net Positive Quarterly Earnings Variance

Favourable
- The average 3.5 per cent increase in customer electricity rates, effective January 1, 2010
- Increased electricity sales

Unfavourable
- Additional operating costs of approximately $2 million incurred in the third quarter of 2010 as a result of Hurricane Igor. The hurricane affected over half of the Company's service territory on September 21, 2010.
- Higher pension costs and inflationary and wage increases
- Higher operating labour costs due to timing. Operating labour costs were lower than anticipated in the first half of 2010 as better weather allowed for an earlier start to capital projects.
- Increased amortization cost associated with continued investment in utility capital assets

Factors Contributing to Net Positive Year-to-Date Earnings Variance

Favourable
- The same factors as discussed above for the quarter

Unfavourable
- Operating costs associated with Hurricane Igor
- Higher retirement and severance expenses, increased conservation and pension costs and wage increases
- Increased amortization cost for the reason discussed above for the quarter
- Higher finance charges associated with interest expense on the $65 million 6.606% bonds issued in May 2009, partially offset by the impact of lower average credit facility borrowings

For a discussion of the nature of regulation and material regulatory decisions and applications pertaining to Newfoundland Power, refer to the "Regulatory Highlights" section of this MD&A.

OTHER CANADIAN ELECTRIC UTILITIES (1)

Financial Highlights (Unaudited)	Quarter			Year-to-date		
Periods Ended September 30	**2010**	2009	Variance	**2010**	2009	Variance
Electricity Sales *(GWh)*	**583**	514	69	**1,750**	1,613	137
($ millions)						
Revenue	**87**	70	17	**244**	205	39
Energy Supply Costs	**57**	46	11	**156**	133	23
Operating Expenses	**11**	8	3	**33**	25	8
Amortization	**7**	5	2	**18**	14	4
Finance Charges	**5**	4	1	**16**	13	3
Corporate Taxes	**2**	2	-	**7**	7	-
Earnings	**5**	5	-	**14**	13	1

(1) Includes Maritime Electric and FortisOntario. FortisOntario includes financial results of Algoma Power from October 8, 2009, the date of acquisition.

Factors Contributing to Positive Quarterly Electricity Sales Variance

Favourable
- Electricity sales at Algoma Power Inc. ("Algoma Power") of 39 gigawatt hours ("GWh") during the third quarter of 2010. Algoma Power was acquired by FortisOntario in October 2009. Excluding electricity sales at Algoma Power, electricity sales increased 5.8 per cent quarter over quarter
- Higher average consumption mainly due to warmer temperatures experienced on Prince Edward Island and in Ontario quarter over quarter

Factors Contributing to Net Positive Year-to-date Electricity Sales Variance

Favourable
- Electricity sales at Algoma Power of 131 GWh year-to-date 2010. Excluding electricity sales at Algoma Power, electricity sales increased less than 1 per cent period over period
- Higher average consumption mainly due to warmer temperatures experienced in Ontario during the third quarter of 2010 compared to the same quarter last year

Unfavourable
- Lower average consumption on Prince Edward Island mainly due to more moderate temperatures experienced during the first quarter of 2010, combined with the impact of conservation initiatives and the economic downturn, partially offset by higher average consumption on Prince Edward Island during the third quarter of 2010 for the reason discussed above for the quarter

Factors Contributing to Positive Quarterly Revenue Variance

Favourable
- Revenue contribution of approximately $8 million from Algoma Power during the third quarter of 2010
- The 5.8 per cent increase in electricity sales, excluding electricity sales at Algoma Power

- An increase at Maritime Electric, effective August 1, 2010, in the base amount of energy-related costs being expensed and collected from customers and recorded in revenue through the basic rate component of customer billings

Factors Contributing to Positive Year-to-Date Revenue Variance

Favourable
- Revenue contribution of approximately $26 million from Algoma Power year-to-date 2010
- The flow through in customer electricity rates of higher energy supply costs at FortisOntario
- An increase at Maritime Electric, effective August 1, 2010, in the base amount of energy-related costs being expensed and collected from customers and recorded in revenue through the basic rate component of customer billings
- The increases in the base component of customer electricity distribution rates at Fort Erie, Gananoque and Port Colborne in Ontario effective May 1, 2009 and May 1, 2010

Factors Contributing to Quarterly and Net Positive Year-to-Date Earnings Variance

Favourable
- Lower finance charges at Maritime Electric due to lower short-term borrowing rates and the repayment of a maturing $15 million first mortgage bond in May 2010 which carried a 12% interest rate.
- Algoma Power contributed approximately $0.5 million to earnings year-to-date 2010

For a discussion of the nature of regulation and material regulatory decisions and applications pertaining to Maritime Electric and FortisOntario, refer to the “Regulatory Highlights” section of this MD&A.

REGULATED ELECTRIC UTILITIES - CARIBBEAN [(1)]

Financial Highlights (Unaudited)	**Quarter**			**Year-to-date**		
Periods Ended September 30	**2010**	2009	Variance	**2010**	2009	Variance
Average US:CDN Exchange Rate [(2)]	**1.04**	1.10	(0.06)	**1.04**	1.16	(0.12)
Electricity Sales *(GWh)*	**318**	312	6	**880**	849	31
($ millions)						
Revenue	**92**	90	2	**251**	255	(4)
Energy Supply Costs	**57**	52	5	**149**	142	7
Operating Expenses	**12**	14	(2)	**35**	42	(7)
Amortization	**9**	9	-	**27**	30	(3)
Finance Charges	**4**	4	-	**13**	12	1
Corporate Tax (Recovery) Expense	**(1)**	-	(1)	**1**	1	-
	11	11	-	**26**	28	(2)
Non-Controlling Interests	**3**	4	(1)	**7**	8	(1)
Earnings	**8**	7	1	**19**	20	(1)

(1) Includes Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos

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

Factors Contributing to Net Positive Quarterly Electricity Sales Variance

Favourable
- Higher average temperatures experienced in Belize and the Turks and Caicos Islands period over period, which increased air-conditioning load
- Customer growth at Belize Electricity and Caribbean Utilities
- Incremental load associated with a new system-connected medical facility and condominium complex in the Turks and Caicos Islands
- Improving tourism activity in the Turks and Caicos Islands, which is favourably impacting large hotel electricity sales
- In July 2010, Fortis Turks and Caicos achieved new record peak load of 31 MW

Unfavourable
- Lower average temperatures and higher rainfall on Grand Cayman quarter over quarter, which decreased air-conditioning load
- Reduced residential customer base at Fortis Turks and Caicos, due to expatriate workers, previously employed in the construction sector, now leaving the Islands
- Continued weak economic conditions tempering growth mainly at Caribbean Utilities

Factors Contributing to Net Positive Year-to-Date Electricity Sales Variance

Favourable
- The same factors as discussed above for the quarter
- Higher average temperatures experienced on Grand Cayman period over period

Unfavourable
- Reduced residential customer base at Fortis Turks and Caicos, for the reason discussed above for the quarter
- Continued weak economic conditions tempering growth mainly at Caribbean Utilities

Factors Contributing to Net Positive Quarterly Revenue Variance

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 1.9 per cent overall increase in electricity sales

Unfavourable
- Approximately $5 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 period over period

Factors Contributing to Net Negative Year-to-Date Revenue Variance

Unfavourable
- Approximately $29 million associated with unfavourable foreign currency translation
- Revenue during the first quarter of 2009 included approximately $1 million associated with a favourable court of appeal judgment at Fortis Turks and Caicos related to a customer rate classification matter.

Favourable
- The flow through in customer electricity rates of higher energy supply costs at Caribbean Utilities, for the reason discussed above for the quarter
- A 2.4 per cent increase in basic customer electricity rates at Caribbean Utilities, effective June 1, 2009
- A 3.7 per cent overall increase in electricity sales

Factors Contributing to Net Positive Quarterly Earnings Variance

Favourable
- The deferral during the third quarter of 2010, for future collection in customer rates, of previously expensed business taxes at Belize Electricity of approximately $1 million
- Lower operating expenses, excluding the impact of foreign exchange, due to a delay in Caribbean Utilities' maintenance program resulting from increased concentration on the utility's capital program, and lower provision for bad debts at Fortis Turks and Caicos, partially offset by increased legal, employee and contractor costs at Belize Electricity
- Increased electricity sales

Unfavourable
- Approximately $0.5 million associated with unfavourable foreign currency translation
- The favourable impact on energy supply costs during the third quarter of 2009, due to a change in the methodology for calculating the cost of fuel recoverable from customers at Fortis Turks and Caicos

Factors Contributing to Net Negative Year-to-Date Earnings Variance

Unfavourable

- Approximately $2.5 million associated with unfavourable foreign currency translation
- Higher finance charges, excluding the impact of foreign exchange, mainly associated with interest expense on the US$40 million 7.5% unsecured notes issued in May 2009 and July 2009 at Caribbean Utilities, and lower capitalized allowance for funds used during construction, combined with higher interest expense on regulatory liabilities at Belize Electricity
- The favourable impact on energy supply costs year-to-date 2009 at Fortis Turks and Caicos, for the reason discussed above for the quarter
- Revenue during the first quarter of 2009 included approximately $1 million associated with the favourable court of appeal judgment at Fortis Turks and Caicos.

Favourable

- Lower operating expenses, excluding the impact of foreign exchange, for the reasons discussed above for the quarter, combined with higher capitalized general and administrative expenses and efforts to control discretionary costs at Caribbean Utilities, partially offset by increased legal, employee and contractor costs at Belize Electricity
- Increased electricity sales
- The 2.4 per cent increase in basic customer electricity rates at Caribbean Utilities, effective June 1, 2009

For additional information on the nature of regulation and material regulatory decisions and applications pertaining to Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos, refer to the "Regulatory Highlights" section of this MD&A.

NON-REGULATED - FORTIS GENERATION [1]

Financial Highlights (Unaudited)	**Quarter**			**Year-to-date**		
Periods Ended September 30	**2010** [2]	2009	Variance	**2010** [2]	2009 [3]	Variance
Energy Sales *(GWh)*	**134**	98	36	**290**	496	(206)
($ millions)						
Revenue	**13**	8	5	**26**	34	(8)
Energy Supply Costs	**-**	-	-	**1**	2	(1)
Operating Expenses	**2**	2	-	**6**	8	(2)
Amortization	**1**	1	-	**3**	4	(1)
Finance Charges	**-**	1	(1)	**-**	3	(3)
Corporate Taxes	**1**	-	1	**2**	2	-
	9	4	5	**14**	15	(1)
Non-Controlling Interests	**-**	-	-	**-**	1	(1)
Earnings	**9**	4	5	**14**	14	-

[1] Includes the results of non-regulated assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State

[2] Results reflect contribution from the Vaca hydroelectric generating facility in Belize, from March 2010 when the facility was commissioned.

[3] Results reflect contribution from the Rankine hydroelectric generating facility in Ontario until April 30, 2009. On April 30, 2009, the Rankine water rights expired at the end of a 100-year term.

Factors Contributing to Net Positive Quarterly Energy Sales Variance

Favourable

- Higher rainfall and the commissioning of the Vaca hydroelectric generating facility in Belize in March 2010. The facility is expected to increase average annual energy production from the Macal River in Belize by approximately 80 GWh. Production by the facility was 35 GWh for the third quarter of 2010.

Unfavourable

- Lower production in Upper New York State due to lower rainfall

Factors Contributing to Net Negative Year-to-Date Energy Sales Variance

Unfavourable

- The expiration on April 30, 2009 of the water rights of the Rankine hydroelectric generating facility in Ontario. Energy sales year-to-date 2009 included approximately 215 GWh related to Rankine.
- Lower production in Upper New York State due to lower rainfall
- Lower energy sales year to date related to central Newfoundland operations. Energy sales for the first quarter of 2009 included 19 GWh related to central Newfoundland operations up until February 12, 2009, at which time the consolidation method of accounting for these operations was discontinued as a consequence of the actions of the Government of Newfoundland and Labrador related to expropriation of the assets of the Exploits River Hydro Partnership (the “Exploits Partnership”).

Favourable

- The same factors as discussed above for the quarter. Production by the Vaca hydroelectric generating facility was 55 GWh year-to-date 2010.

Factors Contributing to Positive Quarterly Revenue Variance

Favourable

- Higher production in Belize

Factors Contributing to Net Negative Year-to-Date Revenue Variance

Unfavourable

- The loss of revenue subsequent to the expiration of the Rankine water rights in April 2009
- The discontinuance of the consolidation method of accounting for the financial results of the Exploits Partnership on February 12, 2009
- Approximately $2 million unfavourable foreign exchange associated with the translation of US dollar-denominated revenue, due to the weakening of the US dollar relative to the Canadian dollar period over period

Favourable

- Higher production in Belize

Factors Contributing to Net Positive Quarterly Earnings Variance

Favourable

- Higher production in Belize
- Reduced finance charges, excluding the impact of foreign exchange, as a result of higher interest revenue associated with inter-company lending to regulated operations in Ontario, partially offset by higher interest expense associated with inter-company lending to finance the construction of the Vaca hydroelectric generating facility. Coincident with the commissioning of the facility in March 2010, capitalization of interest during construction ended.

Unfavourable

- Approximately $1 million associated with unfavourable foreign currency translation

Factors Contributing to Year-to-Date Earnings Variance

Favourable

- The same factors as discussed above for the quarter

Unfavourable

- The expiration of the Rankine water rights. Earnings’ contribution associated with the Rankine hydroelectric generating facility was approximately $3.5 million year-to-date 2009.
- Approximately $2 million associated with unfavourable foreign currency translation

NON-REGULATED - FORTIS PROPERTIES

Financial Highlights (Unaudited) Periods Ended September 30 *($ millions)*	**Quarter** **2010**	 2009	 Variance	**Year-to-date** **2010**	 2009	 Variance
Hospitality Revenue	**44**	44	-	**120**	117	3
Real Estate Revenue	**16**	16	-	**49**	48	1
Total Revenue	**60**	60	-	**169**	165	4
Operating Expenses	**38**	37	1	**113**	109	4
Amortization	**5**	4	1	**13**	12	1
Finance Charges	**6**	6	-	**18**	17	1
Corporate Taxes	**2**	4	(2)	**6**	8	(2)
Earnings	**9**	9	-	**19**	19	-

Factors Contributing to Quarterly Revenue Variance

Favourable

- Higher revenue contribution from hotel properties in central Canada, offset by lower revenue contribution from hotel properties in western and Atlantic Canada
- A 0.6 per cent increase in revenue per available room ("RevPAR") at the Hospitality Division to $89.54 for the third quarter of 2010 from $89.02 for the same quarter in 2009. RevPAR increased due to an overall 0.9 per cent increase in average room rates, partially offset by an overall 0.3 per cent decrease in hotel occupancy. Average room rates at operations in western and central Canada increased, while rates at operations in Atlantic Canada decreased. Hotel occupancy at operations in western Canada decreased, while occupancy at operations in central and Atlantic Canada increased.

Unfavourable

- A decrease in the occupancy rate at the Real Estate Division to 93.7 per cent as at September 30, 2010 from 96.2 per cent as at September 30, 2009, driven by operations in Newfoundland and New Brunswick

Factors Contributing to Net Positive Year-to-Date Revenue Variance

Favourable

- Revenue contribution from the Holiday Inn Select Windsor, acquired in April 2009, combined with higher revenue contribution from hotel properties in Atlantic and central Canada, partially offset by lower revenue contribution from hotel properties in western Canada
- Revenue growth in the Atlantic Canada region of the Real Estate Division, with the most significant increase being in Nova Scotia, mainly due to rent increases
- A $0.2 million gain on sale of land in central Newfoundland during the first quarter of 2010

Unfavourable

- A 0.4 per cent decrease in RevPAR at the Hospitality Division to $78.89 year-to-date 2010 from $79.19 year-to-date 2009. RevPAR decreased due to an overall 2.1 per cent decrease in hotel occupancy, partially offset by an overall 1.7 per cent increase in average room rates. Hotel occupancy at operations in western Canada decreased, while occupancy at operations in central and Atlantic Canada increased. Average room rates at operations in western and Atlantic Canada increased, while rates at operations in central Canada decreased.
- Decreased occupancy rate at the Real Estate Division, as discussed above for the quarter

Factors Contributing to Quarterly Earnings Variance

Favourable

- The impact of a lower effective income tax rate, due to higher deductions taken for tax purposes compared to accounting purposes combined with a lower statutory income tax rate

Unfavourable

- Lower occupancies at hotel operations in western Canada, driven by the continued impact of the economic downturn
- Higher amortization cost, mainly due to capital expansions and improvements

Factors Contributing to Year-to-Date Earnings Variance

Favourable
- The same factor as discussed above for the quarter
- Contribution from the Holiday Inn Select Windsor from April 2009

Unfavourable
- The same factors as discussed above for the quarter
- Increased finance charges due to higher debt levels and interest rates

CORPORATE AND OTHER [(1)]

Financial Highlights (Unaudited) Periods Ended September 30 *($ millions)*	**Quarter** 2010	2009	Variance	**Year-to-date** 2010	2009	Variance
Revenue	**8**	8	-	**23**	21	2
Operating Expenses	**3**	2	1	**13**	9	4
Amortization	**1**	2	(1)	**5**	6	(1)
Finance Charges [(2)]	**20**	21	(1)	**58**	58	-
Corporate Tax Recovery	**(4)**	(5)	1	**(13)**	(14)	1
	(12)	(12)	-	**(40)**	(38)	(2)
Preference Share Dividends	**7**	5	2	**21**	14	7
Net Corporate and Other Expenses	**(19)**	(17)	(2)	**(61)**	(52)	(9)

[(1)] Includes Fortis net corporate expenses, net expenses of non-regulated Terasen corporate-related activities and the financial results of Terasen's 30 per cent ownership interest in CWLP and of Terasen's non-regulated wholly owned subsidiary TES
[(2)] Includes dividends on preference shares classified as long-term liabilities

Factors Contributing to Net Negative Quarterly Net Corporate and Other Expenses Variance

Unfavourable
- Higher preference share dividends, due to the issuance of First Preference Shares, Series H in January 2010. For additional information, see the "Liquidity and Capital Resources" section of this MD&A.

Favourable
- Lower finance charges, mainly due to the repayment of higher interest-bearing debt in 2010, partially offset by the impact of higher average credit facility borrowings. In April 2010, Terasen redeemed its $125 million 8.0% Capital Securities with proceeds from borrowings under the Corporation's committed credit facility.

Factors Contributing to Net Negative Year-to-Date Net Corporate and Other Expenses Variance

Unfavourable
- Higher preference share dividends, as discussed above for the quarter
- Higher operating expenses primarily due to higher business development costs, partially offset by higher recovery of costs from subsidiary companies
- Higher finance charges, excluding the impact of foreign exchange, driven by interest expense on the 30-year $200 million 6.51% unsecured debentures issued in July 2009 and higher average credit facility borrowings, were partially offset by the repayment of higher interest-bearing debt in 2010.

Favourable
- Increased revenue due to interest income on higher inter-company lending to Fortis Properties to finance the Company's maturing external debt
- A favourable foreign exchange impact of approximately $2 million associated with the translation of US dollar-denominated interest expense, due to the weakening of the US dollar relative to the Canadian dollar period over period

REGULATORY HIGHLIGHTS

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

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%) 2008	2009	2010	Supportive Features Future or Historical Test Year Used to Set Customer Rates
			ROE			Cost of Service ("COS")/ROE
TGI	BCUC	40 (1)	8.62	8.47 (2) /9.50 (3)	9.50	TGI: 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
TGVI	BCUC	40	9.32	9.17 (2) /10.00 (3)	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	BCUC	40	9.02	8.87	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 (4)	8.75	9.00	9.00	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	8.95 +/- 50 bps	9.00 +/- 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	10.00	9.75	9.75	COS/ROE
						Future Test Year

Nature of Regulation (cont'd)

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%) 2008	2009	2010	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]	9.00	8.01	8.01	Algoma Power – COS/ROE and subject to Rural Rate Protection Subsidy program
	Algoma Power	50	N/A	8.57	8.57/9.85 [6]	Cornwall Electric - Price cap with commodity cost flow through
	Franchise Agreement Cornwall Electric					Canadian Niagara Power – 2004 historical test year for 2008; 2009 test year for 2009 and 2010 Algoma Power – 2007 historical test year for 2009; 2010 test year for 2010
			ROA [7]			
Belize Electricity	Public Utilities Commission ("PUC")	N/A	10.00	10.00	- [8]	Four-year COS/ ROA agreements Additional costs in the event of a hurricane would be deferred and the Company may apply for future recovery in customer rates.
						Future Test Year
Caribbean Utilities	Electricity Regulatory Authority ("ERA")	N/A	9.00 - 11.00	9.00 - 11.00	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 Caicos	Utilities make annual filings with the Government	N/A	17.50 [9]	17.50 [9]	17.50 [9]	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 2008 and 2009, the allowed deemed equity component of the capital structure was 35 per cent.
(2) Pre-July 1, 2009
(3) Effective July 1, 2009
(4) Effective January 1, 2009. For 2008, the allowed deemed equity component of the capital structure was 37 per cent.
(5) Effective May 1, 2010. For 2009, effective May 1, the allowed deemed equity component of the capital structure was 43.3 per cent.
(6) Proposed at 9.85 per cent effective July 1, 2010, subject to regulatory approval
(7) Rate of return on rate base assets
(8) Allowed ROA to be settled once regulatory matters are resolved
(9) Amount provided under licence. Actual ROAs achieved in 2008 and 2009 were materially lower than the ROA allowed under the licence due to significant investment occurring at the utility.

Material Regulatory Decisions and Applications

Regulated Utility	Summary Description
TGI / TGVI / TGWI	• TGI and TGVI review with the BCUC natural gas and propane commodity rates every three months and mid-stream rates annually 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 or storage capacity. The commodity cost of natural gas and mid-stream costs are flowed through to customers without markup. Effective January 1, 2010, the BCUC approved an increase in mid-stream rates for natural gas and kept commodity rates for natural gas unchanged for customers in the Lower Mainland, Fraser Valley, Interior, North and the Kootenay service areas. Effective April 1, 2010, the BCUC approved an increase in commodity rates for natural gas for customers in the Lower Mainland, Fraser Valley, Interior, North and the Kootenay service areas, while rates for natural gas customers on Vancouver Island and in Whistler and Fort Nelson remained unchanged. Effective July 1, 2010, the BCUC approved decreases in commodity rates for natural gas and propane customers in the Lower Mainland, Fraser Valley, Interior, North and the Kootenay service areas while rates for natural gas customers on Vancouver Island and in Whistler and Fort Nelson remain unchanged. Effective October 2010, commodity rates remained unchanged for all regions. • In November and December 2009, the BCUC approved: (i) NSAs pertaining to the 2010 and 2011 Revenue Requirements Applications for TGI and TGVI; (ii) an increase in TGI's equity component, effective January 1, 2010, to 40 per cent from 35 per cent; (iii) an increase in TGI's allowed ROE, effective July 1, 2009, to 9.50 per cent from 8.47 per cent; and (iv) an increase in the allowed ROE to 10.00 per cent for each of TGVI and TGWI, effective July 1, 2009, from 9.17 per cent and 8.97 per cent, respectively. In its decision on the Return on Equity and Capital Structure Application, the BCUC maintained TGI as a benchmark utility for calculating the allowed ROE for certain utilities regulated by the BCUC. The BCUC also determined that the former automatic adjustment formula used to establish the ROE annually will no longer apply and the allowed ROEs as determined in the BCUC decision will apply until reviewed further by the BCUC. The BCUC-approved NSA for TGI did not include a provision to allow the continued use of a PBR mechanism after the expiry, on December 31, 2009, of TGI's previous PBR agreement. The approved mid-year rate base at TGI is $2,540 million for 2010 and $2,634 million for 2011, and the approved mid-year rate base at TGVI is approximately $555 million for 2010 and $729 million for 2011. The impact at TGI of the approved NSA, the increase in the allowed ROE, the higher equity component and the increase in mid-stream costs was in an increase in customer rates of approximately 10 per cent, effective January 1, 2010, for residential customers in the Lower Mainland, Fraser Valley, Interior, North and Kootenay service areas. Customer rates for TGVI's sales customers, however, will remain unchanged for the two-year period beginning January 1, 2010, as provided in the BCUC-approved NSA for TGVI. • In February 2010, the BCUC approved TGI's application for the in-sourcing of core elements of its customer care services and implementation of a new customer information system, upon the Company accepting a cost risk-sharing condition, whereby TGI would share equally with customers any costs or savings outside a band of plus or minus 10 per cent of the approved total project cost of approximately $116 million, including deferral of certain operating and maintenance expenses. • TGI, TGVI and TGWI are considering an 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. While a decision to proceed with an amalgamation has not yet been made, the Terasen Gas companies are contemplating bringing forth an application during 2011.
FortisBC	• In December 2009, the BCUC approved an NSA pertaining to FortisBC's 2010 Revenue Requirements Application. The result was a general customer electricity rate increase of 6.0 per cent, effective January 1, 2010. The rate increase was primarily the result of the Company's ongoing investment in electrical infrastructure, increasing energy supply costs and the higher cost of capital. FortisBC's allowed ROE has increased to 9.90 per cent, effective January 1, 2010, from 8.87 per cent in 2009 as a result of the BCUC decision to increase the allowed ROE of TGI, the benchmark utility in British Columbia. The BCUC-approved NSA assumes a mid-year rate base of approximately $975 million for 2010. • In June 2010, FortisBC applied to the BCUC for approval of the Company's 2011 Capital Expenditure Plan totalling approximately $114 million, before customer contributions of approximately $11 million, and including approximately $6 million associated with demand side management programs. • In August 2010, FortisBC received BCUC approval for a 2.9 per cent interim, refundable increase in customer rates, effective September 2010. The increase was due to higher power purchase costs being charged to the Company by BC Hydro. • In October 2010, FortisBC filed its Preliminary 2011 Revenue Requirements Application requesting a general customer electricity rate increase of 5.9 per cent, effective January 1, 2011. The requested rate increase is due to the Company's ongoing investment in electrical infrastructure and increasing power purchases driven by customer growth and increased electricity demand.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisBC (cont'd)	• In November 2010, FortisBC received Board of Directors approval to enter into an agreement ("the Waneta Expansion Capacity Agreement") to purchase capacity output from a 335-MW hydroelectric generating facility (the "Waneta Expansion"). The Waneta Expansion Capacity Agreement was accepted by the BCUC in September 2010 and will allow FortisBC to purchase capacity for 40 years, commencing in 2015. For further information on the Waneta Expansion, refer to the "Subsequent Events" section of this MD&A.
FortisAlberta	• In November 2009, the AUC issued its decision on the 2009 Generic Cost of Capital Proceeding ("2009 GCOC Decision") establishing a generic allowed ROE of 9.00 per cent for 2009, 2010, and for 2011 on an interim basis, for all Alberta utilities regulated by the AUC. The allowed ROE of 9.00 per cent is up from the interim allowed ROE of 8.51 per cent for FortisAlberta in 2009. The ROE automatic adjustment formula will no longer apply until reviewed further by the AUC. The AUC also increased FortisAlberta's equity component to 41 per cent from 37 per cent, effective January 1, 2009. The $4.1 million favourable 2009 annual impact of the 2009 GCOC Decision was accrued as revenue in the fourth quarter of 2009 and is expected to be collected in customer electricity rates in 2011. • In December 2009, the AUC approved, on an interim basis, a 7.5 per cent average increase in FortisAlberta's base customer electricity distribution rates, effective January 1, 2010. • In July 2010, the AUC issued a decision on the Company's comprehensive two-year Distribution Tariff Application ("DTA") for 2010 and 2011, which was originally filed in June 2009. The Company has reflected the impact of the decision, retroactive from January 1, 2010, in its third quarter results and has accrued the increased revenue requirements for collection in customer base distribution electricity rates and rate riders expected to begin effective January 1, 2011 for billing implementation. The resulting required increase in customer rates reflects the Company's ongoing investment in electrical infrastructure, to support customer growth and to maintain and upgrade the electricity system, higher forecasted regulatory approved expenses and the impact of the 2009 GCOC Decision. There was no material impact on third quarter 2010 earnings associated with recording the retroactive effects of the rate decision pertaining to the first half of 2010. As normal course, the Company submitted a Compliance Filing in August 2010 in relation to the AUC decision, requesting forecast revenue requirements of $347 million for 2010 and $371 million for 2011. Also included in the Compliance Filing was: (i) forecast operating expenses of $141 million for each of 2010 and 2011; (ii) forecast amortization cost of $125 million for 2010 and $142 million for 2011; (iii) forecast capital expenditures of $290 million for 2010 and $246 million for 2011 and, in addition, forecast Alberta Electric System Operator ("AESO") transmission capital contributions of $54 million for 2010 and $42 million for 2011; and (iv) forecast mid-year rate base of $1,570 million for 2010 and $1,735 million for 2011. Included in the Compliance Filing, as a placeholder, was a successful outcome of the Company's Review and Variance Application and Leave to Appeal, as further discussed below. • In its DTA for 2010 and 2011, FortisAlberta had requested an update in the forecast capital cost of its Automatic Meter Reading ("AMR") Project, bringing the total project cost to $126 million (excluding the cost of the pilot program of $15 million), up from an original project cost of $104 million. The AUC reached the conclusion, however, that the capital cost of the AMR Project of $104 million (excluding the pilot program) had formed part of the Company's 2008/2009 NSA, which had been approved in 2008. The Company has filed a Review and Variance Application with the AUC and a Leave to Appeal with the Alberta Court of Queen's Bench regarding this conclusion. • 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 distribution service rates as early as July 1, 2012. FortisAlberta is currently assessing PBR and will participate fully in the AUC process.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
Newfoundland Power	• In December 2009, the PUB issued a decision on Newfoundland Power's 2010 General Rate Application ("2010 GRA"), resulting in an overall average increase in customer electricity rates of approximately 3.5 per cent, effective January 1, 2010. The rate increase reflects the impact of an increase in the allowed ROE to 9.00 per cent from 8.95 per cent in 2009, as set by the PUB for 2010, ongoing investment in electrical infrastructure and higher forecasted regulatory approved expenses, including pension costs. The PUB decision assumes a mid-year rate base of approximately $869 million for 2010. The PUB also ordered that Newfoundland Power's allowed ROE for each of 2011 and 2012 be determined using the ROE automatic adjustment formula. • In April 2010, the PUB approved the Company's application, as filed, to change the existing ROE automatic adjustment formula. *Consensus Forecasts* will now be used in determining the risk-free rate for calculating the forecast cost of equity to be used in the formula for 2011 and 2012. The previous approach used a ten-day observation of long-term Canada Bond yields as the forecast risk-free rate. • Under the terms of a Joint-Use Facilities Partnership Agreement ("JUFPA") between Newfoundland Power and Bell Aliant (previously, Aliant Telecom Inc.), Newfoundland Power received notice in June 2010 of Bell Aliant's intention to not renew the JUFPA with Newfoundland Power, which expires December 31, 2010, and to repurchase 40 per cent of all joint-use poles from Newfoundland Power for a book-based value. Under the JUFPA, Newfoundland Power acquired approximately 70,000 joint-use distribution poles from Bell Aliant in 2001 for a book-based value of approximately $40 million. Bell Aliant has been renting space on these poles from Newfoundland Power since 2001. The disposition of joint-use poles back to Bell Aliant will require regulatory approval. Upon purchase of the poles, Bell Aliant will also have the obligation to install and maintain 40 per cent of the jointly used poles on an ongoing basis. Once the final terms and conditions have been negotiated between Newfoundland Power and Bell Aliant, Newfoundland Power will be able to assess the impact of the above transaction on its future results of operations, cash flows and financial position. • Newfoundland Power submitted a proposal to the PUB in June 2010 relating to the accounting for, and recovery of, other post-employment benefit ("OPEB") costs. The Company recommended that it: (i) adopt the accrual method of accounting for OPEB costs, effective January 1, 2011; (ii) recover the transitional balance, or regulatory asset, associated with adoption of accrual accounting over a 15-year period; and (iii) adopt a deferral account to capture differences in OPEB costs arising from changes in assumptions associated with the valuation of OPEB obligations. The regulatory asset associated with OPEBs was approximately $47 million as at December 31, 2009. The proposal is currently under review by the PUB. • In July 2010, Newfoundland Power filed an application with the PUB requesting approval for its 2011 Capital Expenditure Plan totaling approximately $73 million, net of customer contributions. • Effective July 1, 2010, there was an overall average increase in electricity rates charged to Newfoundland Power customers of approximately 1.7 per cent. The increase was a result of 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 the electricity that Newfoundland Hydro sells to Newfoundland Power are captured and flowed through to Newfoundland Power customers through the operation of the Rate Stabilization Plan. The increase in customer rates will have no impact on earnings of Newfoundland Power. • In August 2010, Newfoundland Power filed an application with the PUB requesting the deferred recovery of expected increased costs in 2011 of $2.4 million, due to expiring regulatory amortizations. • Newfoundland Power is currently assessing the necessary regulatory action to respond to the additional costs resulting from Hurricane Igor.
Maritime Electric	• In July 2010, IRAC approved Maritime Electric's 2010/2011 Rate Application providing for: (i) an increase in the reference cost of energy in basic electricity rates, effective August 1, 2010; (ii) the amortization of the replacement energy costs incurred during the refurbishment of the New Brunswick Power Point Lepreau Nuclear Generating Station ("Point Lepreau") over the extended life of the unit; and (iii) an allowed ROE of 9.75 per cent for both 2010 and 2011, unchanged from 2009. • In July 2010, Maritime Electric filed its 2011 Capital Budget requesting approval for $23 million in capital expenditures. A decision is expected from IRAC during the fourth quarter of 2010. • In August 2010, the Company filed a Demand-Side Management Plan for 2011-2015 outlining the Company's plan to achieve energy peak reduction required under the *Renewable Energy Act*. • The refurbishment of Point Lepreau continues to be delayed and the station is not expected to return into service until fall 2012. The Government of New Brunswick has stated that it will be seeking mediation with the Government of Canada for the significant incremental cost of replacement energy during the refurbishment.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisOntario	• In April 2010, FortisOntario received Decisions and Orders from the OEB with respect to Third-Generation Incentive Rate Mechanism ("IRM") electricity distribution rate applications for harmonized rates for Fort Erie and Gananoque and rates for Port Colborne, effective May 1, 2010. In non-rebasing years, customer electricity rates are set using inflationary factors less an efficiency target under the OEB's Third-Generation IRM. The resulting increase in base electricity rates, effective May 1, 2010, was minimal, with an inflationary increase of 1.3 per cent partially offset by a 1.12 per cent efficiency target. The approved electricity rates were also based on a deemed capital structure containing 40 per cent equity and reflect an allowed ROE of 8.01 per cent. • In June 2010, FortisOntario filed a new cost of service electricity distribution rate application for Algoma Power for rates, effective July 1, 2010 and January 1, 2011, based on 2010 and 2011 test years, respectively. The application proposed an approximate 14.6 per cent increase in electricity distribution rates in 2010 and an approximate 7.4 per cent increase in rates in 2011. The application is based on a deemed capital structure containing 40 per cent equity and a currently estimated allowed ROE of 9.85 per cent. • During the third quarter of 2010, Algoma Power participated in a settlement conference and submitted a settlement agreement to the OEB for electricity distribution rates, effective December 1, 2010, based on a 2011 test year. The settlement agreement effectively yields approximately 97 per cent of the requested 2011 revenue requirement. A decision on the settlement agreement is expected from the OEB in the fourth quarter of 2010. • In August 2010, FortisOntario notified the OEB that it would not be filing cost of service applications for 2011 electricity distribution rates for Fort Erie, Gananoque and Port Colborne. Rather, the Company has filed Third-Generation IRM electricity distribution rate applications for rates to be effective May 1, 2011 for these areas. FortisOntario does, however, expect to file cost of service applications in April 2011 for harmonized electricity distribution rates for Fort Erie and Gananoque and rates for Port Colborne, effective January 1, 2012, using a 2012 future test year.
Belize Electricity	• Changes made in electricity legislation by the Government of Belize and the PUC, and the PUC's June 2008 Final Decision on Belize Electricity's 2008/2009 Rate Application (the "June 2008 Final Decision") and the PUC's amendment to the June 2008 Final Decision, which were based on the changed legislation, have been judicially challenged by Belize Electricity in several proceedings. The judicial process is ongoing with interim rulings, judgments and appeals. The timing or likely final outcome of the proceedings is indeterminable at this time. In response to an application from Belize Electricity, the Supreme Court of Belize issued an order in June 2010 prohibiting the PUC from carrying out any rate-setting review proceedings, changing any rates and taking any enforcement or penal steps against Belize Electricity until further order of the Supreme Court. • The evidentiary portion of the trial of Belize Electricity's appeal of the PUC's June 2008 Final Decision was heard in October 2010. Closing arguments are expected to be completed in early December 2010 so that the case will be closed pending judgment of the Court.
Caribbean Utilities	• In February 2010, the ERA approved Caribbean Utilities' 2010 Capital Investment Plan ("CIP") at US$21 million for non-generation expansion expenditures. Additional generation needs are subject to a competitive bid process. • In May 2010, Caribbean Utilities submitted its annual RCAM calculations to the ERA as set out in the utility's transmission and distribution licence. The RCAM, which permits base electricity rates to move with inflation, yielded no rate adjustment as of June 1, 2010, as the slight inflation in the US price index was offset by deflation in the Cayman Islands price index for calendar year 2009.
Fortis Turks and Caicos	• In March 2010, Fortis Turks and Caicos submitted its 2009 annual regulatory filing outlining the Company's performance in 2009 and its capital expansion plans for 2010. • In March 2010, Fortis Turks and Caicos filed an Electricity Rate Review with the Ministry of Works, Housing and Utilities of the Government of the Turks and Caicos Islands in accordance with Section 34 of the *Electricity Ordinance*. The filing requested an average 7 per cent increase in base customer electricity rates, effective May 31, 2010. The rate increase would have been the first rate increase implemented by Fortis Turks and Caicos since its inception. The objectives of the Electricity Rate Review included setting rates for the various classes of customers through an Allocated Cost of Service Study, introducing uniformity in the rate structure throughout the service territory of Fortis Turks and Caicos and enabling the utility to start to recover its December 31, 2009 accumulated regulatory shortfall in achieving its allowable profit. • In June 2010, Fortis Turks and Caicos received notice from the Governor of the Turks and Caicos Islands that the Company's Electricity Rate Review filing was not accepted because of concern of the impact that the proposed rate increase might have on key sectors of the Islands' economy. Fortis Turks and Caicos is continuing discussions with the Government and has requested the Governor to appoint an outside, independent consultant to review the filing and the current rate-setting mechanism and make recommendations regarding both.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between September 30, 2010 and December 31, 2009.

Significant Changes in the Consolidated Balance Sheets (Unaudited) between September 30, 2010 and December 31, 2009

Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Accounts receivable	(152)	The decrease was primarily due to the impact of a seasonal decrease in sales, driven by the Terasen Gas companies and Newfoundland Power, partially offset by higher revenue accruals at FortisAlberta.
Regulatory assets - current and long-term	158	The increase was driven by deferrals at the Terasen Gas companies associated with: (i) an $82 million change in the fair market value of the natural gas derivatives; and (ii) the drawdown of the Commodity Cost Reconciliation Account and the Gas Cost Variance Account at TGI and TGVI, respectively, as amounts are being refunded to customers in current commodity rates, partially offset by a reduction in the Midstream Cost Reconciliation Account, as amounts collected in customer rates were in excess of actual mid-stream gas-delivery costs.
Inventories	24	The increase was driven by the normal seasonal increase of gas in storage at the Terasen Gas companies, partially offset by lower natural gas commodity prices.
Utility capital assets	350	The increase primarily related to $672 million invested in electricity and gas systems, partially offset by amortization and customer contributions year-to-date 2010, and the impact of foreign exchange on the translation of foreign currency-denominated utility capital assets.
Short-term borrowings	(74)	The decrease was driven by the reclassification of $70 million borrowed under TGVI's credit facility to long-term debt upon renegotiation of the Company's committed credit facility, the repayment of short-term borrowings by TGI with proceeds from an equity injection from Fortis, and lower borrowings at the Terasen Gas companies due to seasonality of its operations. The decrease was partially offset by higher borrowings at Maritime Electric to finance $15 million of maturing long-term debt, and at Caribbean Utilities to finance capital expenditures.
Accounts payable and accrued charges	(26)	The decrease was driven by lower amounts owing for purchased natural gas at the Terasen Gas companies and purchased power at Newfoundland Power, due to seasonality of operations and lower commodity cost of natural gas at the Terasen Gas companies, and the timing of payment of property taxes and franchise fees at the Terasen Gas companies. The decrease was partially offset by an $82 million change in the fair market value of the natural gas derivatives at the Terasen Gas companies.
Dividends payable	49	The increase was due to the timing of the declaration of common share dividends for the first quarter of 2010.
Regulatory liabilities – current and long-term	23	The increase was mainly due to an increase in the Rate Stabilization Deferral Account at TGVI, reflecting the accumulation of over-recovered costs of providing service to customers year-to-date 2010, an increase in the provision for asset removal and site restoration costs at FortisAlberta and an increase in the Rate Stabilization Account at Belize Electricity, partially offset by a reduction in the Revenue Stabilization Adjustment Mechanism account at TGI, as natural gas consumption volumes were lower than forecast year-to-date 2010.
Long-term debt and capital lease obligations (including current portion)	34	The increase was driven by a net $193 million increase in committed credit facility borrowings classified as long-term and the reclassification of $70 million of committed credit facility borrowings by TGVI from short-term borrowings. The increase was partially offset by regularly scheduled debt repayments, including the repayment of maturing $15 million 12% debentures at Maritime Electric with proceeds from short-term borrowings, the redemption of the $125 million 8.0% Capital Securities at Terasen with proceeds from borrowings under the Corporation's committed credit facility, the repayment of approximately $47 million of maturing debt at Fortis Properties with proceeds from borrowings under the Corporation's committed credit facility, and the impact of foreign exchange on the translation of foreign currency-denominated long-term debt.

Significant Changes in the Consolidated Balance Sheets (Unaudited) between September 30, 2010 and December 31, 2009 (cont'd)

Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Future income tax liabilities – current and long-term	27	The increase was driven by tax timing differences related to capital expenditures at FortisAlberta and FortisBC.
Shareholders' equity	306	The increase was driven by the issuance of $250 million five-year fixed rate reset preference shares in January 2010. The remainder of the increase was due to net earnings attributable to common equity shareholders year-to-date 2010, less common share dividends, and the issuance of common shares under the Corporation's share purchase, dividend reinvestment and stock option plans.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Consolidated Cash Flows: The table below outlines the Corporation's consolidated sources and uses of cash for the three and nine months ended September 30, 2010, as compared to the same periods in 2009, followed by a discussion of the nature of the variances in cash flows.

Summary of Consolidated Cash Flows (Unaudited)						
Periods Ended September 30		**Quarter**			**Year-to-date**	
($ millions)	**2010**	2009	Variance	**2010**	2009	Variance
Cash, Beginning of Period	**71**	137	(66)	**85**	66	19
Cash Provided by (Used in):						
Operating Activities	**129**	63	66	**582**	567	15
Investing Activities	**(253)**	(251)	(2)	**(658)**	(733)	75
Financing Activities	**117**	159	(42)	**55**	209	(154)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**-**	(2)	2	**-**	(3)	3
Cash, End of Period	**64**	106	(42)	**64**	106	(42)

Operating Activities: Cash flow from operating activities, after working capital adjustments, was $66 million higher quarter over quarter, mainly due to higher earnings, the collection from customers of increased amortization costs driven by the Terasen Gas companies and favourable working capital changes at the Terasen Gas companies, reflecting differences in the commodity cost of natural gas and the cost of natural gas charged to customers quarter over quarter and the differing effects of seasonality.

Cash flow from operating activities, after working capital adjustments, was $15 million higher year to date compared to the same period in 2009. The favourable impact of: (i) higher earnings; (ii) the collection from customers of increased amortization costs driven by the Terasen Gas companies; (iii) favourable changes in the AESO charges deferral account at FortisAlberta; (iv) the timing of property tax and other payments at FortisBC; (v) a decrease in the amount of corporate taxes paid at the Terasen Gas companies and Newfoundland Power; and (vi) the timing of the declaration of common share dividends for the first quarter of 2010 were partially offset by otherwise unfavourable working capital changes at the Terasen Gas companies. The unfavourable working capital changes were due to differences in the commodity cost of natural gas and the cost of natural gas charged to customers period over period and the differing effects of seasonality.

Investing Activities: Cash used in investing activities was comparable quarter over quarter. Cash used in investing activities was $75 million lower year to date compared to the same period in 2009, driven by lower gross capital expenditures at FortisAlberta, mainly due to lower demand for new residential services, irrigation and farm services and lower spending related to equipment, facilities and AESO transmission capital projects. Lower gross capital expenditures at Regulated Electric Utilities – Caribbean were largely offset by higher gross capital expenditures at FortisBC.

Financing Activities: Cash provided by financing activities was $42 million lower quarter over quarter, driven by: (i) lower proceeds from long-term debt; (ii) lower net proceeds from short-term borrowings; and (iii) higher common and preference share dividends, partially offset by: (i) higher proceeds from net borrowings under committed credit facilities; (ii) lower repayments of long-term debt; and (iii) higher proceeds from the issuance of common shares.

Cash provided by financing activities was $154 million lower year to date compared to the same period in 2009, driven by: (i) lower proceeds from long-term debt; (ii) higher repayments of long-term debt; and (iii) higher common and preference share dividends, partially offset by: (i) higher proceeds from net borrowings under committed credit facilities; (ii) lower net repayments of short-term borrowings; and (iii) higher proceeds from the issuance of preference and common shares.

Net proceeds from short-term borrowings were $46 million lower quarter over quarter and net repayments of short-term borrowings were $67 million lower year to date compared to the same period in 2009. The changes in short-term borrowings mainly related to the Terasen Gas companies associated with working capital and capital expenditure requirements, and repayments with cash from operations and, in January 2010, with proceeds from an equity injection by the Corporation.

Proceeds from long-term debt, net of issue costs, repayments of long-term debt and capital lease obligations and net borrowings (repayments) 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 September 30	Quarter			Year-to-date		
($ millions)	**2010**	2009	Variance	**2010**	2009	Variance
Terasen Gas Companies	**-**	-	-	**-**	99 [(1)]	(99)
FortisAlberta	**-**	-	-	**-**	99 [(2)]	(99)
FortisBC	**-**	-	-	**-**	104 [(3)]	(104)
Newfoundland Power	**-**	-	-	**-**	65 [(4)]	(65)
Caribbean Utilities	**-**	11 [(5)]	(11)	**-**	45 [(5)]	(45)
Corporate	**-**	198 [(6)]	(198)	**-**	198 [(6)]	(198)
Total	**-**	209	(209)	**-**	610	(610)

(1) Issued February 2009, 30-year $100 million 6.55% unsecured debentures by TGI. The net proceeds were used to repay credit facility borrowings and repay $60 million 10.75% unsecured debentures that matured in June 2009.

(2) Issued February 2009, 30-year $100 million 7.06% unsecured debentures. The net proceeds were used to repay committed credit facility borrowings and for general corporate purposes.

(3) Issued June 2009, 30-year $105 million 6.10% unsecured debentures. The net proceeds were used to repay committed credit facility borrowings, for general corporate purposes, including financing capital expenditures and working capital requirements, and to help repay $50 million 6.75% debentures that matured in July 2009.

(4) Issued May 2009, 30-year $65 million 6.606% first mortgage sinking fund bonds. The net proceeds were used to repay committed credit facility borrowings and for general corporate purposes, including financing capital expenditures.

(5) Issued May 2009 and July 2009, 15-year US$30 million and US$10 million, respectively, 7.50% unsecured notes. The net proceeds were used to repay short-term borrowings and finance capital expenditures.

(6) Issued July 2009, 30-year $200 million 6.51% unsecured debentures. The net proceeds were used to repay, in full, the indebtedness outstanding under the Corporation’s committed credit facility and for general corporate purposes.

Repayments of Long-Term Debt and Capital Lease Obligations (Unaudited)

Periods Ended September 30	Quarter			Year-to-date		
($ millions)	**2010**	2009	Variance	**2010**	2009	Variance
Terasen Gas Companies	**-**	-	-	**(1)**	(63)	62
FortisBC	**-**	(51)	51	**(1)**	(51)	50
Maritime Electric	**-**	-	-	**(15)**	-	(15)
Caribbean Utilities	**-**	-	-	**(15)**	(16)	1
Fortis Properties	**(1)**	(6)	5	**(53)**	(11)	(42)
Corporate - Terasen	**-**	-	-	**(125)** [1]	-	(125)
Other	**(2)**	-	(2)	**(5)**	(7)	2
Total	**(3)**	(57)	54	**(215)**	(148)	(67)

[1] In April 2010, Terasen redeemed in full for cash its $125 million 8.0% Capital Securities with proceeds from borrowings under the Corporation's committed credit facility.

Net Borrowings (Repayments) Under Committed Credit Facilities (Unaudited)

Periods Ended September 30	Quarter			Year-to-date		
($ millions)	**2010**	2009	Variance	**2010**	2009	Variance
FortisAlberta	**22**	36	(14)	**82**	37	45
FortisBC	**15**	2	13	**27**	(29)	56
Newfoundland Power	**(18)**	(5)	(13)	**(5)**	(32)	27
Corporate	**17**	(144)	161	**89**	(30)	119
Total	**36**	(111)	147	**193**	(54)	247

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.

Proceeds from the issuance of common shares increased $11 million quarter over quarter and $26 million year to date compared to the same period in 2009, reflecting the impact of the participation by shareholders in the Corporation's Dividend Reinvestment and Share Purchase Plan. The plan provides participating common shareholders a 2 per cent discount on the purchase of common shares, issued from treasury, with reinvested dividends.

In January 2010, Fortis completed a $250 million offering of five-year fixed rate reset 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 to fund an equity injection into TGI.

Common share dividends were $48 million for the third quarter, up $3 million from the same quarter in 2009, due mainly to an increase in the quarterly common share dividend. Common share dividends were $193 million year to date, up $60 million from the same period in 2009. The increase was primarily due to the timing of the declaration of common share dividends for the first quarter of 2010 and an increase in the quarterly common share dividends. The dividend declared per common share in each of the first, second and third quarters of 2010 was $0.28, while the dividend declared per common share in each of the first, second and third quarters of 2009 was $0.26.

Preference share dividends increased $2 million quarter over quarter and $7 million year to date compared to the same period in 2009, as a result of the dividends associated with the 10 million First Preference Shares, Series H that were issued in January 2010.

Contractual Obligations: Consolidated contractual obligations of Fortis with external third parties over the next five years and for periods thereafter, as of September 30, 2010, are outlined in the following table. A detailed description of the nature of the obligations is provided below and in the MD&A for the year ended December 31, 2009.

Contractual Obligations (Unaudited) As at September 30, 2010 *($ 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	**5,534**	155	594	839	3,946
Brilliant Terminal Station	**60**	3	5	5	47
Gas purchase contract obligations (1)	**660**	394	189	77	-
Power purchase obligations					
FortisBC (2)	**2,932**	43	90	81	2,718
FortisOntario	**471**	32	96	169	174
Maritime Electric	**45**	26	2	2	15
Belize Electricity	**181**	20	38	43	80
Capital cost	**417**	19	36	32	330
Joint-use asset and shared service agreements (3)	**64**	4	7	7	46
Office lease – FortisBC	**18**	1	3	3	11
Operating lease obligations	**138**	17	30	27	64
Equipment purchase – Fortis Turks and Caicos	**3**	3	-	-	-
Defined benefit pension funding contributions (4)	**40**	20	16	2	2
Other (5)	**21**	5	9	6	1
Total	**10,584**	742	1,115	1,293	7,434

(1) Based on index prices as at September 30, 2010

(2) During the first quarter of 2010, FortisBC entered into a contract with Powerex Corp., a wholly owned subsidiary of BC Hydro, for fixed-price winter capacity purchases through to February 2016 in an aggregate amount of approximately US$16 million. If FortisBC brings any new resources, such as capital or contractual projects, on-line prior to the expiry of this agreement, FortisBC may terminate this contract any time after July 1, 2013 with a minimum of three-months' written notice to Powerex Corp.

(3) In September 2010, FortisAlberta and an Alberta transmission service provider renewed shared-service agreements for an additional five years for a total of approximately $4 million.

(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 the above 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, 2010	Terasen (covering unionized employees) and FortisBC
December 31, 2011	Newfoundland Power

The estimate of defined pension funding contributions above includes the impact of the outcome of the December 31, 2009 actuarial valuation, finalized during the third quarter of 2010, associated with the defined benefit pension plan covering non-unionized employees at Terasen.

(5) Other contractual obligations include capital lease obligations, operating building leases, and asset-retirement obligations at FortisBC.

Other Contractual Obligations:

In prior years, TGVI received non-interest bearing repayable loans from the federal and provincial governments of $50 million and $25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. The government loans are repayable in any fiscal year prior to 2012 under certain circumstances and subject to the ability of TGVI to obtain non-government subordinated debt financing on reasonable commercial terms. As the loans are repaid and replaced with non-government loans, utility capital assets and long-term debt will increase in accordance with TGVI's approved capital structure, as will TGVI's rate base, which is used in determining customer rates. The repayment criteria were met in 2009 and TGVI made an approximate $4 million repayment on the loans during the second quarter of 2010. As at September 30, 2010, the outstanding balance of the repayable government loans was approximately $49 million, with approximately $4 million classified as current portion of long-term debt. Repayments of the government loans are not included in the contractual obligations table above as the amount and timing of the repayments are dependent upon the ability of TGVI to replace the government loans with non-government subordinated debt financing on reasonable commercial terms. TGVI, however, estimates making payments under the loans of $20 million in 2012, $14 million over 2013 and 2014 and $15 million thereafter.

Caribbean Utilities has a primary fuel supply contract with a major supplier and is committed to purchase 80 per cent of the Company's fuel requirements from this supplier for the operation of Caribbean Utilities' diesel-powered generating plant. The initial contract was for three years and terminated in April 2010. Caribbean Utilities continues to operate within the terms of the initial contract. The contract contains an automatic renewal clause for years 2010 through 2012. Should any party choose to terminate the contract within that two-year period, notice must be given a minimum of one year in advance of the desired termination date. No such termination notice has been given by either party to date. As such, the contract is effectively renewed until 2011. The quantity of fuel to be purchased under the contract for 2010 is approximately 25 million imperial gallons.

Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

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. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 40 per cent equity, including preference shares, and 60 per cent 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 utility's customer rates.

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

Capital Structure (Unaudited)	**As at**			
	September 30, 2010		December 31, 2009	
	($ millions)	***(%)***	*($ millions)*	*(%)*
Total debt and capital lease obligations (net of cash) [1]	**5,811**	**58.2**	5,830	60.2
Preference shares [2]	**912**	**9.2**	667	6.9
Common shareholders' equity	**3,255**	**32.6**	3,193	32.9
Total [3]	**9,978**	**100.0**	9,690	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 issuance of $250 million preference shares in January 2010 and increased common shares outstanding, reflecting the impact of the Corporation's Dividend Reinvestment and Share Purchase Plan. Repayments of long-term debt and capital lease obligations year-to-date 2010 were largely offset by an increase in committed credit facility borrowings.

Credit Ratings: The Corporation's credit ratings are as follows:

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

In October 2010, DBRS upgraded the Corporation's unsecured debt credit rating to A(low) from BBB(high). In May 2010, S&P confirmed its existing debt credit rating for Fortis at A-(stable). These credit ratings, and the recent upgrade by DBRS, 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 and the significant reduction in external debt at Terasen, the Corporation's strong credit metrics, and the Corporation's demonstrated ability and continued focus of acquiring and integrating stable regulated utility businesses financed on a conservative basis.

Capital Program: The Corporation's principal businesses of regulated gas and electricity distribution are capital intensive. 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.

Year-to-date 2010, gross consolidated capital expenditures were $703 million. A breakdown of gross consolidated capital expenditures by segment year-to-date 2010 is provided in the following table.

Gross Consolidated Capital Expenditures (Unaudited) [(1)]
Year-to-date September 30, 2010
($ millions)

Terasen Gas Companies	Fortis Alberta [(2)]	FortisBC	Newfoundland Power	Other Regulated Electric Utilities - Canadian	**Total Regulated Utilities - Canadian**	**Regulated Electric Utilities - Caribbean**	**Non-Regulated - Utility** [(3)]	**Fortis Properties**	**Total**
182	258	99	56	33	**628**	**53**	**8**	**14**	**703**

(1) Relates to utility capital assets, income producing properties and intangible assets and includes capital expenditures associated with assets under construction. Includes asset removal and site restoration expenditures, net of salvage proceeds, for those utilities where such expenditures are permissible in rate base in 2010. 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 capital projects
(3) Includes non-regulated generation and corporate capital expenditures

There has been no material change in forecast gross consolidated capital expenditures for 2010 from the approximate $1.1 billion forecast as was disclosed in the MD&A for the year ended December 31, 2009. 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 are no significant updates 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, 2009, except as described below.

During 2010, TGI's Fraser River South Bank South Arm Rehabilitation Project experienced difficulties with one of the directional drills and the project is now expected to be in service in 2011, rather than in 2010. The project is now expected to cost approximately $36 million, increased from the $27 million forecast as at December 31, 2009.

During 2010, FortisAlberta has continued with the replacement of conventional customer meters with AMR technology. The capital cost of the AMR project is now expected to be approximately $126 million (excluding $15 million for the pilot program), a decrease from the $140 million (excluding the pilot program) forecast as at December 31, 2009. In July 2010, the AUC limited the project cost to $104 million, which was the original amount provided in the AUC-approved 2008/2009 NSA. As of the end of October 2010, approximately $106 million has been incurred on this project. For further information, refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

In May 2010, Fortis Turks and Caicos received delivery of one of two diesel-powered generating units that have a combined generating capacity of approximately 18 MW. Commissioning of the first unit began in October 2010 and the unit is expected to come into service in January 2011. The delivery of the second unit is anticipated in January 2011.

In October 2010, the Corporation, in partnership with Columbia Power Corporation and Columbia Basin Trust ("CPC/CBT"), concluded definitive agreements to construct the Waneta Expansion, at an estimated cost of approximately $900 million. Construction is expected to start in November 2010. For additional information, refer to the "Subsequent Events" section of this MD&A.

Over the five-year period 2011 through 2015, consolidated gross capital expenditures are expected to approach $5.5 billion, including work on the Waneta Expansion Project. Of the capital spending, approximately 63 per cent is expected to be incurred at the Regulated Electric Utilities, driven by FortisAlberta and FortisBC, 21 per cent is expected to be incurred at the Regulated Gas Utilities and 16 per cent is expected to be incurred at the non-regulated operations. Capital expenditures at the Regulated Utilities are subject to regulatory approval.

Cash Flow Requirements: At the operating subsidiary level, it is expected that operating expenses and interest costs will generally be paid out of subsidiary 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.

Over the next five years, as at September 30, 2010, management expects consolidated long-term debt maturities and repayments to average approximately $320 million annually. 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 a result of the regulator's Final Decision on Belize Electricity's 2008/2009 Rate Application in June 2008, Belize Electricity does not meet certain debt covenant financial ratios related to loans with the International Bank for Reconstruction and Development and the Caribbean Development Bank totalling $5 million (BZ$10 million) as at September 30, 2010.

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 $58 million as at September 30, 2010 (December 31, 2009 - $59 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.

Except for the debt at Belize Electricity and the Exploits Partnership, as discussed above, Fortis and its subsidiaries were in compliance with debt covenants as at September 30, 2010 and are expected to remain compliant throughout 2010.

Credit Facilities: As at September 30, 2010, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.1 billion, of which $1.2 billion was unused, including $386 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 per cent of these facilities. Approximately $2.0 billion of the total credit facilities are committed facilities, most of which have maturities between 2011 and 2013.

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	**September 30, 2010**	December 31, 2009
Total credit facilities	645	1,453	13	**2,111**	2,153
Credit facilities utilized:					
Short-term borrowings	-	(340)	(1)	**(341)**	(415)
Long-term debt (including current portion)	(214)	(244)	-	**(458)**	(208)
Letters of credit outstanding	(1)	(111)	-	**(112)**	(100)
Credit facilities unused	430	758	12	**1,200**	1,430

As at September 30, 2010 and December 31, 2009, 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 2010, Maritime Electric renewed its $50 million unsecured committed revolving credit facility, which matures annually in March. During the second quarter of 2010, Maritime Electric increased its unsecured committed revolving credit facility by $10 million.

In April 2010, FortisBC amended its credit facility agreement obtaining an extension to the maturity of its $150 million unsecured committed revolving credit facility with $100 million now maturing in May 2013 and $50 million now maturing in May 2011.

In May 2010, TGVI entered into a two-year $300 million unsecured committed revolving credit facility to replace its $350 million credit facility that was due to mature in January 2011. The terms of the new $300 million credit facility are substantially similar to the terms of the former $350 million credit facility, but there is an increase in pricing reflecting current general market conditions.

In August 2010, Newfoundland Power renegotiated and amended its $100 million unsecured committed credit facility obtaining an extension to the maturity of the facility to August 2013 from August 2011. The amended credit facility agreement reflects an increase in pricing as a result of current general market conditions but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

FINANCIAL INSTRUMENTS

The carrying values of financial instruments included in current assets, current liabilities, other assets and other liabilities in the consolidated balance sheets of Fortis approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments. The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, 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 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.

The carrying and fair values of the Corporation's consolidated long-term debt and preference shares were as follows.

Financial Instruments (Unaudited)	**As at**			
	September 30, 2010		December 31, 2009	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt, including current portion [(1)]	**5,534**	**6,407**	5,502	5,906
Preference shares, classified as debt [(2)]	**320**	**350**	320	348

[(1)] Carrying value as at September 30, 2010 excludes unamortized deferred financing costs of $38 million (December 31, 2009 - $39 million) and capital lease obligations of $38 million (December 31, 2009 - $37 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 $610 million as at September 30, 2010 (December 31, 2009 - carrying value $347 million; fair value $356 million).

Risk Management: The Corporation's earnings from, and net investment 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. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars or a currency pegged to the US dollar. Belize Electricity's reporting currency is the Belizean dollar, while the reporting currency of Caribbean Utilities, Fortis Turks and Caicos, FortisUS Energy Corporation and Belize Electric Company Limited is the US dollar. The Belizean dollar is pegged to the US dollar at BZ$2.00=US$1.00.

As at September 30, 2010, all of the Corporation's corporately issued US$390 million (December 31, 2009 – US$390 million) long-term debt had been designated as a hedge of a portion of the Corporation's foreign net investments. As at September 30, 2010, the Corporation had approximately US$199 million (December 31, 2009 – US$174 million) in foreign net investments remaining to be hedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately held US dollar borrowings designated as hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency gains and losses on the foreign net investments, which are also recorded in other comprehensive income.

From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates 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.

Derivative Financial Instruments (Unaudited)			**As at**			
	September 30, 2010				December 31, 2009	
Liability	**Term to Maturity *(years)***	**Number of Contracts**	**Carrying Value *($ millions)***	**Estimated Fair Value *($ millions)***	Carrying Value *($ millions)*	Estimated Fair Value *($ millions)*
Interest rate swap	**< 1**	**1**	**-**	**-**	-	-
Foreign exchange forward contracts	**< 1 to 2**	**2**	**-**	**-**	-	-
Natural gas derivatives:						
Swaps and options	**Up to 4**	**206**	**(202)**	**(202)**	(119)	(119)
Gas purchase contract premiums	**Up to 3**	**87**	**(2)**	**(2)**	(3)	(3)

The interest rate swap, which matured in October 2010, was held by Fortis Properties and was designated as a hedge of the cash flow risk related to floating-rate long-term debt and matured in October 2010. The effective portion of changes in the value of the interest rate swap at Fortis Properties was recorded in other comprehensive income.

The foreign exchange forward contracts are held by the Terasen Gas companies. During the first quarter of 2010, TGI entered into a foreign exchange forward contract to hedge the cash flow risk related to approximately US$11 million remaining to be paid under a contract for the implementation of a customer information system. TGVI also hedges the cash flow risk related to approximately US$3 million remaining to be paid under a contract for the construction of a liquefied natural gas storage facility.

The natural gas derivatives are held by the Terasen Gas 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 Terasen Gas 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. See the "Business Risk Management – Commodity Price Risk" section of this MD&A for further information.

The changes in the fair values of the foreign exchange forward 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 foreign exchange forward contracts were recorded in accounts receivable as at September 30, 2010 and as at December 31, 2009. The fair values of the natural gas derivatives were recorded in accounts payable as at September 30, 2010 and as at December 31, 2009.

The interest rate swap was valued at the present value of future cash flows based on published forward future interest rate curves. 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 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 and natural gas derivatives are estimates of the amounts the Terasen Gas companies would have to receive or pay if forced to settle all 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

As at September 30, 2010, 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

A detailed discussion of the Corporation's significant business risks is provided in the MD&A for the year ended December 31, 2009. There were no changes in the Corporation's significant business risks year-to-date 2010 from those disclosed in the MD&A for the year ended December 31, 2009, except for those described below.

Regulatory Risk: In July 2010, the AUC issued its decision on FortisAlberta's 2010 and 2011 revenue requirements application, the effects of which were reflected in the third quarter of 2010. Maritime Electric also received a regulatory decision on its revenue requirements application for rates effective August 1, 2010 with an allowed ROE of 9.75 per cent approved for each of 2010 and 2011. See the "Regulatory Highlights – Material Regulatory Decisions and Applications" section of this MD&A for further information on regulation.

Capital Project Budget Overruns and Financing Risk in the Corporation's Non-Regulated Business: In its non-regulated business, Fortis generally bears the risk for budget overruns on capital projects including increased costs associated with higher financing expense, schedule delays and worse than expected performance. In contrast, these budget overruns, when incurred prudently in the regulated business, can be recovered in customer rates as part of cost of service. Budgets for capital projects are established, in part, on estimates which are subject to a number of assumptions including future economic conditions; productivity; performance of employees, contractors, subcontractors or equipment suppliers; price; availability of labour, equipment and materials and other requirements that may affect project costs or the schedule, such as obtaining the required environmental permits, licenses and approvals on a timely basis. The risk of cost overruns is mitigated by contractual approach, regular and proactive monitoring by employees with appropriate expertise and by regular review by senior management. Cost overruns may also occur when unforeseen circumstances arise. The cost of financing large capital projects is subject to conditions experienced in the capital markets which may result in higher financing costs than originally estimated. See the "Subsequent Events" section of this MD&A for further information on the non-regulated Waneta Expansion Project.

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.

Year-to-date 2010, Moody's has confirmed its existing debt credit ratings for Terasen, TGI, TGVI, FortisAlberta and Newfoundland Power and upgraded FortisBC's senior unsecured debt credit rating to Baa1 from Baa2. DBRS also upgraded FortisBC's secured and unsecured debenture credit rating to A(low) from BBB(high). The credit rating upgrades for FortisBC reflect progress made by the Company in addressing issues previously identified as credit challenges. DBRS has confirmed its existing debt credit ratings for Terasen and TGI and upgraded the credit rating of the Corporation's unsecured debt to A(low) from at BBB(high). See the "Liquidity and Capital Resources – Credit Ratings" section of this MD&A. S&P has also confirmed its existing debt credit ratings for FortisAlberta and the Corporation, and its existing corporate credit rating for Maritime Electric. S&P, however, lowered Maritime Electric's senior secured debt credit rating to A- from A and revised the recovery rating on the debt to '1' from '1+'.

Commodity Price Risk: On an annual basis, Terasen files a Price Risk Management Plan which seeks approval for the Company's gas commodity hedging plan for the next three years for TGI and the next five years for TGVI. During the third quarter of 2010, the BCUC denied the application that was filed by Terasen earlier in 2010 and directed the Company to undertake a review of the primary objectives of the Price Risk Management Plan. Terasen plans to file its review of the Price Risk Management Plan with the BCUC by the end of February 2011. Terasen has completed its hedging program for the upcoming winter period related to previously approved Price Risk Management Plans, but has not entered into any additional derivatives for any subsequent periods.

Defined Benefit Pension Plan Performance and Funding Requirements: As at September 30, 2010, the fair value of the Corporation's consolidated defined benefit pension plan assets was $706 million, up $45 million, or 6.8 per cent, from $661 million as at December 31, 2009.

CHANGES IN ACCOUNTING POLICIES AND STANDARDS

Effective January 1, 2010, as required by the regulator, FortisAlberta began capitalizing to utility capital assets a portion of the amortization of utility capital assets, such as tools and vehicles, used in the construction of other assets. During the three and nine months ended September 30, 2010, amortization of $1 million and $3 million, respectively, was capitalized.

Effective January 1, 2010, as a result of the BCUC-approved NSAs related to 2010 and 2011 revenue requirements, the Terasen Gas companies adopted the following new accounting policies:

(i) Asset removal costs are now recorded in operating expenses on the consolidated statement of earnings. The annual amount of such costs approved for recovery in customer rates in 2010 is approximately $8 million. Actual costs incurred in excess of, or below, the approved amount are to be recorded in a regulatory deferral account for recovery from, or refund to, customers in future rates, beginning in 2012. Removal costs are direct costs incurred by the Terasen Gas companies in taking assets out of service, whether through actual removal of the assets or through the disconnection of the assets from the transmission or distribution system. For the three months ended September 30, 2010, actual asset removal costs of approximately $3 million were incurred, with $2 million recorded in operating expenses and $1 million deferred as a regulatory asset. For the nine months ended September 30, 2010, actual asset removal costs of approximately $8 million were incurred, with approximately $6 million recorded in operating expenses and $2 million deferred as a regulatory asset. Prior to January 1, 2010, asset removal costs were recorded against accumulated amortization on the consolidated balance sheet.

(ii) Gains and losses on the sale or disposal of utility capital assets are now recorded in a regulatory deferral account on the consolidated balance sheet for recovery from, or refund to, customers in future rates, subject to regulatory approval. During the three and nine months ended September 30, 2010, losses of approximately $6 million and $11 million, respectively, were deferred and recorded as a regulatory asset on the consolidated balance sheet. Prior to January 1, 2010, gains and losses on the sale or disposal of utility capital assets were recorded against accumulated amortization on the consolidated balance sheet.

(iii) Amortization of utility capital assets and intangible assets now commences the month after the assets are available for use. Prior to January 1, 2010, amortization commenced the year following when the assets became available for use. During 2010, additional amortization expense of approximately $2 million is expected to be incurred, due to the change in commencement of amortization of utility capital assets and intangible assets.

Business Combinations

Effective January 1, 2010, the Corporation early adopted the new Canadian Institute of Chartered Accountants ("CICA") Handbook Section 1582, *Business Combinations*, together with Section 1601, *Consolidated Financial Statements* and Section 1602, *Non-Controlling Interests*. As a result of adopting Section 1582, changes in the determination of the fair value of the assets and liabilities of an acquiree in a business combination results in a different calculation of goodwill with respect to acquisitions on or after January 1, 2010. Such changes include the expensing of acquisition-related costs incurred during a business acquisition, rather than recording them as a capital transaction, and the disallowance of recording restructuring accruals by the acquirer. The adoption of Section 1582 did not have a material impact on the Corporation's interim unaudited consolidated financial statements for the three and nine months ended September 30, 2010.

Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 establishes standards for accounting for non-controlling interests in a subsidiary in consolidated financial statements subsequent to a business combination. The adoption of Sections 1601 and 1602 resulted in non-controlling interests being presented as components of equity, rather than as liabilities, on the consolidated balance sheet. Also, net earnings and components of other comprehensive income attributable to the owners of the parent company and to non-controlling interests are now separately disclosed on the consolidated statement of earnings and consolidated statement of comprehensive income.

FUTURE ACCOUNTING CHANGES

Transition to International Financial Reporting Standards

A detailed discussion of the Corporation's transition to International Financial Reporting Standards ("IFRS") is provided in the MD&A for the year ended December 31, 2009. The Corporation is still unable to fully determine the impact on its future financial position and results of operations of the transition to IFRS, particularly as it relates to the accounting for rate-regulated activities. Completion of the Rate-Regulated Activities Project by the International Accounting Standards Board ("IASB") had been delayed based on comments received in response to the IASB's July 2009 Exposure Draft on *Rate-Regulated Activities* and decisions by the IASB to conduct further research and analysis.

The IASB met in July 2010 and discussed the key issue of whether regulatory assets and liabilities can be recognized based on the current IFRS - *Framework for the Preparation and Presentation of Financial Statements*. As a result of those meetings, the IASB decided to continue with the Rate-Regulated Activities Project; however, no decision was made as to whether regulatory assets and liabilities could be recognized under IFRS.

At its September 2010 meeting, the IASB continued its discussions on rate-regulated activities. However, the IASB did not reach conclusions on any of the associated technical issues discussed at the meeting. The IASB did reconfirm its earlier view that the matter could not be resolved quickly and decided that the next step should be to consider whether to include a project on accounting for the effects of rate-regulated activities in its future agenda. The IASB decided, therefore, to include on its future agenda, in consultation with the public, a request for views on what form a future project might take, if any, to address accounting for the effects of rate-regulated activities. The feedback to be received is expected to assist the IASB in setting its future agenda. Potential future steps on how to deal with accounting for the effects of rate-regulated activities under IFRS include, but are not limited to: (i) a disclosure only standard; (ii) an interim standard to grandfather previous country-specific GAAP associated with accounting for the effects of rate-regulated activities with some limited improvements; (iii) a medium-term project focused specifically on accounting for the effects of rate-regulation; and/or (iv) a comprehensive project on intangible assets that would include accounting for the effects of rate-regulated activities.

On July 28, 2010, the Canadian Accounting Standards Board ("AcSB") issued an Exposure Draft, *Adoption of IFRSs by Entities with Rate-Regulated Activities*, (the "July 2010 ED") proposing that qualifying entities with rate-regulated activities be permitted, but not required, to continue applying the accounting standards in Part V of the CICA Handbook for an additional two years. A qualifying entity would be an entity that: (i) has activities subject to rate regulation meeting the definition of that term in *Generally Accepted Accounting Principles*, paragraph 1100.32B, in Part V of the CICA Handbook; and (ii) in accordance with Accounting Guideline AcG-19, *Disclosures by Entities*

Subject to Rate Regulation, discloses that it has accounted for a transaction or event differently than it would have in the absence of rate regulation, i.e., that it has recognized regulatory assets and liabilities. The July 2010 ED also proposed that an entity choosing to defer its IFRS changeover date disclose that fact and when it will first present financial statements in accordance with IFRS.

On September 7 and 8, 2010, the AcSB re-deliberated the proposals in its July 2010 ED. The AcSB decided that an optional deferral of the mandatory IFRS changeover date for entities with rate-regulated activities was warranted, but that the deferral should last for one year only. Part I of the CICA Handbook has been updated to reflect the AcSB's decision. Adoption of IFRS by qualifying entities with rate-regulated activities is now mandatory under Canadian GAAP for interim and annual periods beginning on or after January 1, 2012.

While the Corporation's IFRS Conversion Project has proceeded as planned in preparation for the adoption of IFRS on January 1, 2011, Fortis and its rate-regulated subsidiaries do qualify for the one-year deferral option. The Corporation has elected to defer the adoption of IFRS until January 1, 2012 and will, therefore, continue to prepare its consolidated financial statements in accordance with Part V of the CICA Handbook for all interim and annual periods ending on or before December 31, 2011.

A Canadian publicly accountable entity that is also registered with the US Securities and Exchange Commission ("SEC") (i.e., an "SEC Issuer") has the option to use US Generally Accepted Accounting Principles ("US GAAP") for the purposes of meeting its Canadian financial reporting and securities filing requirements. Depending on the extent of progress with respect to the application of IFRS to rate-regulated activities and the ability to recognize regulatory assets and liabilities under IFRS, the Corporation may consider whether US GAAP, as opposed to IFRS, would provide the most useful and relevant presentation of its financial results. If determined to be in its best interests, the Corporation may, therefore, seek to become an SEC Issuer and use US GAAP as its basis of accounting for all interim and annual periods beginning on or after January 1, 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 for the three and nine months ended September 30, 2010 from those disclosed in the Corporation's MD&A for the year ended December 31, 2009, except for those described below.

Capital Asset Amortization: As a result of a recent depreciation study and BCUC-approved NSAs related to TGI and TGVI's 2010 and 2011 revenue requirements, annual amortization expense at the Terasen Gas companies is expected to increase in 2010, reflecting an increase in the composite depreciation rate to 2.79 per cent for 2010 from 2.63 per cent for 2009.

During the third quarter of 2010, FortisAlberta submitted a Compliance Filing, related to its 2010 and 2011 DTA, which included forecast amortization expense of $125 million and $142 million for 2010 and 2011, respectively. The forecast amortization expense reflects an increase in the composite amortization rate to 4.27 per cent for 2010 from 3.94 per cent for 2009.

The increases in amortization at TGI, TGVI and FortisAlberta has been approved for recovery in customer rates.

Asset-Retirement Obligations: During the second quarter of 2010, FortisBC obtained sufficient information to determine an estimate of the fair value and timing of the estimated future expenditures associated with the removal of polychlorinated biphenyls ("PCB")-contaminated oil from its electrical equipment. All factors used in estimating the Company's asset-retirement obligation represent management's best estimate of the fair value of the costs required to meet existing legislation or regulations. It is reasonably possible that volumes of contaminated assets, inflation assumptions, cost estimates to perform the work and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. The asset-retirement obligation may change from period to period because of changes in the estimation of these uncertainties. As at September 30, 2010, FortisBC has recognized approximately $3 million in asset-retirement obligations, which have been classified on the consolidated balance sheet as long-term other liabilities with the offset to utility capital assets.

Capitalized Overhead: As required by their regulator, the Terasen Gas companies capitalize overhead costs not directly attributable to specific capital projects but related to the overall capital program. Effective January 1, 2010, as provided in the BCUC-approved NSAs for 2010 and 2011, the percentage for calculating and capitalizing general overhead costs to utility capital assets at the Terasen Gas companies has changed. The percentage of total general operating and maintenance costs being allocated and capitalized to utility capital assets has decreased from 16 per cent to 14 per cent. As a result of this change, operating expenses increased approximately $1 million for the third quarter and approximately $3 million year to date over the same periods in 2009, with corresponding decreases in utility capital assets. The resulting increase in operating expenses has been approved for recovery in current customer delivery rates.

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 contingencies from those disclosed in the MD&A for the year ended December 31, 2009, except for those described below.

Terasen

TGI had disputed a $7 million assessment of British Columbia Social Services Tax representing additional provincial sales tax and interest on the Southern Crossing Pipeline, which was completed in 2000. The amount was paid in full in 2006 to avoid the accrual of further interest and was recorded as a long-term regulatory deferral asset. TGI was successful in its appeal to the British Columbia Court of Appeal, which took place in May 2010. During the third quarter of 2010, TGI received a refund of the majority of the balance with the amount withheld relating to a separate reassessment.

In 2009, Terasen was named, along with other defendants, in an action related to damages to property and chattels, including contamination to sewer lines and costs associated with remediation, related to the rupture in July 2007 of an oil pipeline owned and operated by Kinder Morgan. Terasen has filed a statement of defence but the claim is in its early stages. During the second quarter of 2010, Terasen was added as a third party in all of the related actions and all claims are expected to be tried at the same time. The amount and outcome of the actions are indeterminable at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Maritime Electric

In June 2010, Maritime Electric reached a Settlement Agreement with Canada Revenue Agency related to the reassessment of the Company's 1997-2004 taxation years. In the Settlement Agreement, Maritime Electric's treatment of the Energy Cost Adjustment Mechanism was accepted; however, the reassessments with respect to customer rebate adjustments and the Company's settlement payment to New Brunswick Power regarding the write-down of Point Lepreau would stand. During the third quarter of 2010, final reassessments were received and Canada Revenue Agency refunded the Company's $6 million deposit. As ordered by its regulator, the $6 million refund has been applied to the outstanding balance associated with the operation of the Energy Cost Adjustment Mechanism.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended December 31, 2008 through September 30, 2010. 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 and 4 to the Corporation's 2009 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)

Quarter Ended	Revenue ($ millions)	Net Earnings Attributable to Common Equity Shareholders ($ millions)	Earnings per Common Share Basic ($)	Earnings per Common Share Diluted ($)
September 30, 2010	720	45	0.26	0.26
June 30, 2010	834	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
June 30, 2009	756	53	0.31	0.31
March 31, 2009	1,202	92	0.54	0.52
December 31, 2008	1,181	76	0.48	0.46

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 and mid-stream cost of natural gas, which are flowed through to customers without markup. Given the diversified nature of the Fortis subsidiaries, seasonality may vary. Because of natural gas consumption patterns, the earnings of the Terasen Gas companies are highest in the first and fourth quarters. Financial results for the fourth quarter ended December 31, 2008 included two additional months of contribution from Caribbean Utilities, resulting from a change in the utility's fiscal year end. Financial results from May 1, 2009 have been impacted, as expected, by the loss of revenue and earnings subsequent to the expiration, in April 2009, of the water rights of the Rankine hydroelectric generating facility in Ontario. Financial results for the fourth quarter ended December 31, 2009 reflected the favourable cumulative retroactive impact associated with an increase in the allowed ROEs for 2009 for FortisAlberta and TGI, and an increase in the equity component at FortisAlberta. The commissioning of the Vaca hydroelectric generating facility in March 2010 has favourably impacted financial results since this date. Revenue for the third quarter ended September 30, 2010 reflected the favourable cumulative retroactive impact associated with a 2010-2011 regulatory rate decision for FortisAlberta. To a lesser degree, financial results from November 2008 were impacted by the acquisition of the Sheraton Hotel Newfoundland, from April 2009 by the acquisition of the Holiday Inn Select Windsor and from October 2009 by the acquisition of Algoma Power.

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 Terasen Gas companies and higher corporate expenses. Improved performance at the regulated utilities in western Canada was due to higher allowed ROEs and/or equity component, 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 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 quarter over quarter at the Terasen Gas companies largely related to increased operating and maintenance expenses at TGI 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.

June 2010/June 2009 - Net earnings attributable to common equity shareholders were $55 million, or $0.32 per common share, for the second quarter of 2010 compared to earnings of $53 million, or $0.31 per common share, for the second quarter of 2009. The increase in earnings was driven by the Terasen Gas companies and FortisBC, partially offset by higher corporate expenses. The increase in earnings at the Terasen Gas companies related to higher allowed ROEs and equity component. The improvement in earnings at FortisBC was the result of a higher allowed ROE and growth in electrical infrastructure investment, partially offset by lower electricity sales due to cooler weather experienced in June 2010. The increase in corporate expenses was mainly due to higher business development costs and preference share dividends, partially offset by higher interest income related to increased inter-company lending. Earnings at FortisAlberta were comparable quarter over quarter. The impact of a higher allowed ROE and equity component, compared to those reflected in FortisAlberta's earnings for the second quarter of 2009, combined with growth in electrical infrastructure investment and an increase in customers was mainly offset by lower corporate income tax recoveries and lower net transmission revenue.

March 2010/March 2009 - Net earnings attributable to common equity shareholders were $100 million, or $0.58 per common share, for the first quarter of 2010 compared to earnings of $92 million, or $0.54 per common share, for the first quarter of 2009. The increase in earnings was led by the Terasen Gas companies associated with an increase in the allowed ROEs and equity component. Results also reflected: (i) improved performance at FortisAlberta, associated with an increase in the allowed ROE and equity component combined with growth in electrical infrastructure investment and an increase in customers; and (ii) increased earnings at Newfoundland Power, mainly due to growth in electrical infrastructure investment, increased electricity sales and timing differences favourably impacting operating expenses during the quarter. Earnings' growth was tempered by: (i) lower earnings' contribution from non-regulated hydroelectric generation operations due to loss of earnings subsequent to the expiration of the Rankine water rights in April 2009; (ii) lower contribution from Caribbean Regulated Electric Utilities associated with the unfavourable impact of foreign exchange translation, and earnings in the first quarter of 2009 including an approximate $1 million one-time gain; and (iii) higher preference share dividends.

December 2009/December 2008 - Net earnings attributable to common equity shareholders were $81 million, or $0.48 per common share, for the fourth quarter of 2009 compared to earnings of $76 million, or $0.48 per common share, for the fourth quarter of 2008. Fourth quarter results for 2009 were favourably impacted by a one-time $3 million adjustment to future income taxes related to prior periods at FortisOntario and were unfavourably impacted by a one-time $5 million after-tax provision for additional costs related to the conversion of Whistler customer appliances from propane to natural gas. Fourth quarter results for 2008 included two additional months of earnings' contribution from Caribbean Utilities (August and September 2008) of approximately $2 million due to a change in the utility's fiscal year end. Excluding the above one-time items, earnings increased $9 million quarter over quarter. The increase was driven by: (i) the approximate $10 million cumulative retroactive impact in the fourth quarter of 2009 associated with the increase in the allowed ROEs for 2009 for FortisAlberta and TGI and an increase in the equity component at FortisAlberta; and (ii) a change in depreciation estimates at Fortis Turks and Caicos, which favourably impacted amortization expense for the fourth quarter of 2009. The increase was partially offset by lower earnings' contribution from non-regulated hydroelectric generation operations due to loss of earnings subsequent to the expiration of the Rankine water rights in April 2009.

SUBSEQUENT EVENTS

In October 2010, the Corporation, in partnership with CPC/CBT, concluded definitive agreements to construct the Waneta Expansion at an estimated cost of approximately $900 million, and SNC-Lavalin was awarded a contract for approximately $590 million to design and build the Waneta Expansion. The facility is sited adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia and will have a generating capacity of 335 MW. CBC/CBT are both 100 per cent owned corporations of the Government of British Columbia. Fortis owns a 51 per cent interest in the Waneta Expansion and will operate and maintain the non-regulated investment when the facility comes into service, which is expected in spring 2015. Construction is expected to start in November 2010. The Waneta Expansion will be included in the Canal Plant Agreement and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing hydrologic risk associated with the project. The energy, approximately 630 GWh, (and associated capacity required to deliver such energy) for the Waneta Expansion will be sold to BC Hydro under a long-term energy purchase agreement. The surplus capacity, equal to 234 MW on an average annual basis, will be sold to FortisBC under a long-term capacity purchase agreement, which was accepted by the BCUC in September 2010.

In October 2010, FortisAlberta issued 40-year $125 million 4.80% unsecured debentures, the net proceeds of which will be used to repay committed credit facility borrowings that were incurred primarily to finance capital expenditures, and for general corporate purposes.

In October 2010, Fortis redeemed its maturing $100 million 7.40% senior unsecured debentures with proceeds from borrowings under the Corporation's committed credit facility.

OUTLOOK

The Corporation's significant capital program, which is expected to be approximately $1.1 billion in 2010 and approach $5.5 billion over the five-year period from 2011 through 2015, including work on the Waneta Expansion Project, 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 November 4, 2010, the Corporation had issued and outstanding 173.7 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 November 4, 2010 is as follows:

Potential Conversion of Securities into Common Shares (Unaudited) **As at November 4, 2010** (Security)	**Number of Common Shares** *(millions)*
Stock Options	4.9
Convertible Debt	1.4
First Preference Shares, Series C	3.9
First Preference Shares, Series E	6.4
Total	16.6

Additional information, including the Fortis 2009 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 nine months ended September 30, 2010 and 2009
(Unaudited)

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

	September 30, 2010	December 31, 2009 (Notes 2 & 22)
ASSETS		
Current assets		
Cash and cash equivalents	**$ 64**	$ 85
Accounts receivable	**443**	595
Prepaid expenses	**33**	16
Regulatory assets (Note 5)	**299**	223
Inventories (Note 6)	**202**	178
Future income taxes	**12**	29
	1,053	1,126
Other assets	**170**	174
Regulatory assets (Note 5)	**829**	747
Future income taxes	**22**	17
Utility capital assets	**8,047**	7,697
Income producing properties	**560**	559
Intangible assets	**270**	282
Goodwill	**1,557**	1,560
	$ 12,508	$ 12,162
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings (Note 19)	**$ 341**	$ 415
Accounts payable and accrued charges	**826**	852
Dividends payable	**52**	3
Income taxes payable	**15**	23
Regulatory liabilities (Note 5)	**45**	53
Current installments of long-term debt and capital lease obligations (Note 7)	**158**	224
Future income taxes	**6**	24
	1,443	1,594
Other liabilities	**310**	295
Regulatory liabilities (Note 5)	**475**	444
Future income taxes	**615**	570
Long-term debt and capital lease obligations (Note 7)	**5,376**	5,276
Preference shares	**320**	320
	8,539	8,499
Shareholders' equity		
Common shares (Note 8)	**2,555**	2,497
Preference shares (Note 9)	**592**	347
Contributed surplus	**13**	11
Equity portion of convertible debentures	**5**	5
Accumulated other comprehensive loss (Note 11)	**(88)**	(83)
Retained earnings	**770**	763
	3,847	3,540
Non-controlling interests	**122**	123
	3,969	3,663
	$ 12,508	$ 12,162

Contingent liabilities and commitments (Note 20)

See accompanying Notes to Interim Consolidated Financial Statements

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

	Quarter Ended		Nine Months Ended	
	2010	2009 (Note 2)	**2010**	2009 (Note 2)
Revenue	**$ 720**	$ 665	**$ 2,627**	$ 2,623
Expenses				
Energy supply costs	**259**	253	**1,178**	1,279
Operating	**196**	183	**600**	565
Amortization	**117**	91	**307**	274
	572	527	**2,085**	2,118
Operating income	**148**	138	**542**	505
Finance charges (Note 13)	**88**	91	**266**	267
Earnings before corporate taxes	**60**	47	**276**	238
Corporate taxes (Note 14)	**5**	2	**48**	34
Net earnings	**$ 55**	$ 45	**$ 228**	$ 204
Net earnings attributable to:				
Non-controlling interests	**$ 3**	$ 4	**$ 7**	$ 9
Preference equity shareholders	**7**	5	**21**	14
Common equity shareholders	**45**	36	**200**	181
	$ 55	$ 45	**$ 228**	$ 204
Earnings per common share (Note 8)				
Basic	**$ 0.26**	$ 0.21	**$ 1.16**	$ 1.06
Diluted	**$ 0.26**	$ 0.21	**$ 1.15**	$ 1.05

See accompanying Notes to Interim Consolidated Financial Statements

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

	Quarter Ended		Nine Months Ended	
	2010	2009 (Note 2)	**2010**	2009 (Note 2)
Balance at beginning of period	**$ 773**	$ 691	**$ 763**	$ 634
Net earnings attributable to common and preference equity shareholders	**52**	41	**221**	195
	825	732	**984**	829
Dividends on common shares	**(48)**	(45)	**(193)**	(133)
Dividends on preference shares classified as equity	**(7)**	(5)	**(21)**	(14)
Balance at end of period	**$ 770**	$ 682	**$ 770**	$ 682

See accompanying Notes to Interim Consolidated Financial Statements

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

	Quarter Ended		Nine Months Ended	
	2010	2009 (Note 2)	**2010**	2009 (Note 2)
Net earnings	**$ 55**	$ 45	**$ 228**	$ 204
Other comprehensive (loss) income				
Unrealized foreign currency translation losses on net investments in self-sustaining foreign operations	**(21)**	(51)	**(13)**	(79)
Gains on hedges of net investments in self-sustaining foreign operations	**13**	37	**8**	59
Corporate tax expense	**(2)**	(5)	**(1)**	(8)
Unrealized foreign currency translation losses, net of hedging activities and tax (Note 11)	**(10)**	(19)	**(6)**	(28)
Gain on derivative instruments designated as cash flow hedges, net of tax (Note 11)	**-**	-	**-**	1
Reclassification to earnings of net losses on derivative instruments previously discontinued as cash flow hedges, net of tax (Note 11)	**1**	-	**1**	-
Comprehensive income	**$ 46**	$ 26	**$ 223**	$ 177
Comprehensive income attributable to:				
Non-controlling interests	**$ 3**	$ 4	**$ 7**	$ 9
Preference equity shareholders	**7**	5	**21**	14
Common equity shareholders	**36**	17	**195**	154
	$ 46	$ 26	**$ 223**	$ 177

See accompanying Notes to Interim Consolidated Financial Statements

Fortis Inc.
Consolidated Statements of Cash Flows (Unaudited)
For the periods ended September 30
(in millions of Canadian dollars)

	Quarter Ended		Nine Months Ended	
	2010	2009	**2010**	2009
		(Note 2)		(Note 2)
Operating activities				
Net earnings	**$ 55**	$ 45	**$ 228**	$ 204
Items not affecting cash:				
Amortization - utility capital assets and income producing properties	**107**	78	**276**	238
Amortization - intangible assets	**10**	12	**30**	32
Amortization - other	**-**	1	**1**	4
Future income taxes	**-**	2	**(1)**	9
Other	**(3)**	(2)	**(1)**	(9)
Change in long-term regulatory assets and liabilities	**(4)**	7	**(4)**	30
	165	143	**529**	508
Change in non-cash operating working capital	**(36)**	(80)	**53**	59
	129	63	**582**	567
Investing activities				
Change in other assets and other liabilities	**(2)**	1	**1**	(4)
Capital expenditures - utility capital assets	**(256)**	(251)	**(672)**	(725)
Capital expenditures - income producing properties	**(5)**	(4)	**(14)**	(15)
Capital expenditures - intangible assets	**(7)**	(12)	**(17)**	(23)
Contributions in aid of construction	**17**	14	**41**	40
Proceeds on sale of utility capital assets	**-**	1	**3**	1
Business acquisition	**-**	-	**-**	(7)
	(253)	(251)	**(658)**	(733)
Financing activities				
Change in short-term borrowings	**122**	168	**(4)**	(71)
Proceeds from long-term debt, net of issue costs	**-**	209	**-**	610
Repayments of long-term debt and capital lease obligations	**(3)**	(57)	**(215)**	(148)
Net borrowings (repayments) under committed credit facilities	**36**	(111)	**193**	(54)
Advances (to) from non-controlling interests	**-**	(5)	**1**	(5)
Issue of common shares, net of costs	**19**	8	**58**	32
Issue of preference shares, net of costs	**-**	-	**242**	-
Dividends				
Common shares	**(48)**	(45)	**(193)**	(133)
Preference shares	**(7)**	(5)	**(21)**	(14)
Subsidiary dividends paid to non-controlling interests	**(2)**	(3)	**(6)**	(8)
	117	159	**55**	209
Effect of exchange rate changes on cash and cash equivalents	**-**	(2)	**-**	(3)
Change in cash and cash equivalents	**(7)**	(31)	**(21)**	40
Cash and cash equivalents, beginning of period	**71**	137	**85**	66
Cash and cash equivalents, end of period	**$ 64**	$ 106	**$ 64**	$ 106

Supplementary Information to Consolidated Statements of Cash Flows (Note 16)

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 Corporation's long-term objectives. 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 2009 annual audited consolidated financial statements.

REGULATED UTILITIES

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

a. *Regulated Gas Utilities – Canadian:* Consists of the Terasen Gas companies, including Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc.

b. *Regulated Electric Utilities – Canadian:* Consists of FortisAlberta; 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, as of October 2009, Algoma Power Inc. ("Algoma Power").

c. *Regulated Electric Utilities – Caribbean:* Consists of Belize Electricity, in which Fortis holds an approximate 70 per cent controlling ownership interest; Caribbean Utilities, in which Fortis holds an approximate 59 per cent controlling ownership interest; and wholly owned Fortis Turks and Caicos, which includes P.P.C. Limited and Atlantic Equipment & Power (Turks and Caicos) Ltd.

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 2.8 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 Terasen Inc. ("Terasen") corporate-related activities, and the financial results of Terasen's 30 per cent ownership interest in CustomerWorks Limited Partnership and of Terasen's non-regulated wholly owned subsidiary 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 2009 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, earnings of the Terasen Gas companies are highest 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 2009 annual audited consolidated financial statements, except as described below.

Effective January 1, 2010, as required by the regulator, FortisAlberta began capitalizing to utility capital assets a portion of the amortization of utility capital assets, such as tools and vehicles, used in the construction of other assets. During the three and nine months ended September 30, 2010, amortization of $1 million and $3 million, respectively, was capitalized.

Effective January 1, 2010, as a result of the British Columbia Utilities Commission ("BCUC")-approved Negotiated Settlement Agreements ("NSAs") related to 2010 and 2011 revenue requirements, the Terasen Gas companies adopted the following new accounting policies:

(i) Asset removal costs are now recorded in operating expenses on the consolidated statement of earnings. The annual amount of such costs approved for recovery in customer rates in 2010 is approximately $8 million. Actual costs incurred in excess of, or below, the approved amount are to be recorded in a regulatory deferral account for recovery from, or refund to, customers in future rates, beginning in 2012. Removal costs are direct costs incurred by the Terasen Gas companies in taking assets out of service, whether through actual removal of the assets or through the disconnection of the assets from the transmission or distribution system. For the three months ended September 30, 2010, actual asset removal costs of approximately $3 million were incurred, with $2 million recorded in operating expenses and $1 million deferred as a regulatory asset. For the nine months ended September 30, 2010, actual asset removal costs of approximately $8 million were incurred, with approximately $6 million recorded in operating expenses and $2 million deferred as a regulatory asset. Prior to January 1, 2010, asset removal costs were recorded against accumulated amortization on the consolidated balance sheet.

(ii) Gains and losses on the sale or disposal of utility capital assets are now recorded in a regulatory deferral account on the consolidated balance sheet for recovery from, or refund to, customers in future rates, subject to regulatory approval. During the three and nine months ended September 30, 2010, losses of approximately $6 million and $11 million, respectively, were deferred and recorded as a regulatory asset on the consolidated balance sheet (Note 5). Prior to January 1, 2010, gains and losses on the sale or disposal of utility capital assets were recorded against accumulated amortization on the consolidated balance sheet.

(iii) Amortization of utility capital assets and intangible assets now commences the month after the assets are available for use. Prior to January 1, 2010, amortization commenced the year following when the assets became available for use. During 2010, additional amortization expense of approximately $2 million is expected to be incurred, due to the change in commencement of amortization of utility capital assets and intangible assets.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Effective January 1, 2010, the Corporation adopted the following new accounting standards issued by the Canadian Institute of Chartered Accountants ("CICA").

Business Combinations
Effective January 1, 2010, the Corporation early adopted the new CICA Handbook Section 1582, *Business Combinations,* together with Section 1601, *Consolidated Financial Statements* and Section 1602, *Non-Controlling Interests.* As a result of adopting Section 1582, changes in the determination of the fair value of the assets and liabilities of an acquiree in a business combination results in a different calculation of goodwill with respect to acquisitions on or after January 1, 2010. Such changes include the expensing of acquisition-related costs incurred during a business acquisition, rather than recording them as a capital transaction, and the disallowance of recording restructuring accruals by the acquirer. The adoption of Section 1582 did not have a material impact on the Corporation's interim consolidated financial statements for the three and nine months ended September 30, 2010.

Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 establishes standards for accounting for non-controlling interests in a subsidiary in consolidated financial statements subsequent to a business combination. The adoption of Sections 1601 and 1602 resulted in non-controlling interests being presented as components of equity, rather than as liabilities, on the consolidated balance sheet. Also, net earnings and components of other comprehensive income attributable to the owners of the parent company and to non-controlling interests are now separately disclosed on the consolidated statement of earnings and consolidated statement of comprehensive income.

3. FUTURE ACCOUNTING CHANGES

International Financial Reporting Standards
In October 2009, the Canadian Accounting Standards Board ("AcSB") re-confirmed that publicly accountable enterprises in Canada will be required to apply International Financial Reporting Standards ("IFRS"), in full and without modification, beginning January 1, 2011. An IFRS transition date of January 1, 2011 would require the restatement, for comparative purposes, of amounts reported on the Corporation's consolidated opening IFRS balance sheet as at January 1, 2010 and amounts reported by the Corporation for the year ended December 31, 2010.

Fortis is continuing to assess the financial reporting impacts of adopting IFRS. In July 2009, the International Accounting Standards Board ("IASB") issued the Exposure Draft - *Rate-Regulated Activities.* Based on the Exposure Draft, regulatory assets and liabilities arising from activities subject to cost of service regulation would be recognized under IFRS when certain conditions are met. The ability to record regulatory assets and liabilities, as proposed in the Exposure Draft, would reduce the earnings' volatility at the Corporation's regulated utilities that may otherwise result under IFRS in the absence of an accounting standard for rate-regulated activities, but will result in the requirement to provide enhanced balance sheet presentation and note disclosures. Completion of the IASB's Rate-Regulated Activities Project had been delayed based on comments received in response to the Exposure Draft and decisions by the IASB to conduct further research and analysis.

The IASB met in July 2010 and discussed the key issue of whether regulatory assets and liabilities can be recognized based on the current IFRS - *Framework for the Preparation and Presentation of Financial Statements*. As a result of those meetings, the IASB decided to continue with the Rate-Regulated Activities Project; however, no decision was made as to whether regulatory assets and liabilities could be recognized under IFRS.

At its September 2010 meeting, the IASB continued its discussions on rate-regulated activities. However, the IASB did not reach conclusions on any of the associated technical issues discussed at the meeting.

3. FUTURE ACCOUNTING CHANGES (cont'd)

International Financial Reporting Standards (cont'd)

The IASB did reconfirm its earlier view that the matter could not be resolved quickly and decided that the next step should be to consider whether to include a project on accounting for the effects of rate-regulated activities in its future agenda. The IASB decided, therefore, to include on its future agenda, in consultation with the public, a request for views on what form a future project might take, if any, to address accounting for the effects of rate-regulated activities. The feedback to be received is expected to assist the IASB in setting its future agenda. Potential future steps on how to deal with accounting for the effects of rate-regulated activities under IFRS include, but are not limited to: (i) a disclosure only standard; (ii) an interim standard to grandfather previous country-specific GAAP associated with accounting for the effects of rate-regulated activities with some limited improvements; (iii) a medium-term project focused specifically on accounting for the effects of rate-regulation; and/or (iv) a comprehensive project on intangible assets that would include accounting for the effects of rate-regulated activities.

On July 28, 2010, the AcSB issued an Exposure Draft, *Adoption of IFRSs by Entities with Rate-Regulated Activities*, (the "July 2010 ED") proposing that qualifying entities with rate-regulated activities be permitted, but not required, to continue applying the accounting standards in Part V of the CICA Handbook for an additional two years. A qualifying entity would be an entity that: (i) has activities subject to rate regulation meeting the definition of that term in *Generally Accepted Accounting Principles*, paragraph 1100.32B, in Part V of the Handbook; and (ii) in accordance with Accounting Guideline AcG-19, *Disclosures by Entities Subject to Rate Regulation*, discloses that it has accounted for a transaction or event differently than it would have in the absence of rate regulation, i.e., that it has recognized regulatory assets and liabilities. The July 2010 ED also proposed that an entity choosing to defer its IFRS changeover date disclose that fact and when it will first present financial statements in accordance with IFRS.

On September 7 and 8, 2010, the AcSB re-deliberated the proposals in its July 2010 ED. The AcSB decided that an optional deferral of the mandatory IFRS changeover date for entities with rate-regulated activities was warranted, but that the deferral should last for one year only. Part I of the CICA Handbook has been updated to reflect the AcSB's decision. Adoption of IFRS by qualifying entities with rate-regulated activities is now mandatory under Canadian GAAP for interim and annual periods beginning on or after January 1, 2012.

While the Corporation's IFRS Conversion Project has proceeded as planned in preparation for the adoption of IFRS on January 1, 2011, Fortis and its rate-regulated subsidiaries do qualify for the one-year deferral option. The Corporation has elected to defer the adoption of IFRS until January 1, 2012 and will, therefore, continue to prepare its consolidated financial statements in accordance with Part V of the CICA Handbook for all interim and annual periods ending on or before December 31, 2011.

A Canadian publicly accountable entity that is also registered with the US Securities and Exchange Commission ("SEC") (i.e., an "SEC Issuer") has the option to use US Generally Accepted Accounting Principles ("US GAAP") for the purposes of meeting its Canadian financial reporting and securities filing requirements. Depending on the extent of progress with respect to the application of IFRS to rate-regulated activities and the ability to recognize regulatory assets and liabilities under IFRS, the Corporation may consider whether US GAAP, as opposed to IFRS, would provide the most useful and relevant presentation of its financial results. If determined to be in its best interests, the Corporation may, therefore, seek to become an SEC Issuer and use US GAAP as its basis of accounting for all interim and annual periods beginning on or after January 1, 2012.

4. USE OF ESTIMATES

The preparation of the Corporation's interim 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 nine months ended September 30, 2010, except for that described below and in Note 20 as it relates to contingencies.

Capital Asset Amortization: As a result of a recent depreciation study and BCUC-approved NSAs related to TGI and TGVI's 2010 and 2011 revenue requirements, annual amortization expense at the Terasen Gas companies is expected to increase in 2010, reflecting an increase in the composite depreciation rate to 2.79 per cent for 2010 from 2.63 per cent for 2009.

During the third quarter of 2010, FortisAlberta submitted a Compliance Filing, related to its 2010 and 2011 Distribution Tariff Application, which included forecast amortization expense of $125 million and $142 million for 2010 and 2011, respectively. The forecast amortization expense reflects an increase in the composite amortization rate to 4.27 per cent for 2010 from 3.94 per cent for 2009.

The increase in amortization at TGI, TGVI and FortisAlberta has been approved for recovery in customer rates.

Asset-Retirement Obligations: During the second quarter of 2010, FortisBC obtained sufficient information to determine an estimate of the fair value and timing of the estimated future expenditures associated with the removal of polychlorinated biphenyls ("PCB")-contaminated oil from its electrical equipment. All factors used in estimating the Company's asset-retirement obligation represent management's best estimate of the fair value of the costs required to meet existing legislation or regulations. It is reasonably possible that volumes of contaminated assets, inflation assumptions, cost estimates to perform the work and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. The asset-retirement obligation may change from period to period because of changes in the estimation of these uncertainties. As at September 30, 2010, FortisBC has recognized approximately $3 million in asset-retirement obligations, which have been classified on the consolidated balance sheet as long-term other liabilities with the offset to utility capital assets.

Capitalized Overhead: As required by their regulator, the Terasen Gas companies capitalize overhead costs not directly attributable to specific capital projects but related to the overall capital program. Effective January 1, 2010, as provided in the BCUC-approved NSAs as described above, the percentage for calculating and capitalizing general overhead costs to utility capital assets at the Terasen Gas companies has changed. The percentage of total general operating and maintenance costs being allocated and capitalized to utility capital assets has decreased from 16 per cent to 14 per cent. As a result of this change, operating expenses increased approximately $1 million for the third quarter and approximately $3 million year to date over the same periods in 2009, with corresponding decreases in utility capital assets. The resulting increase in operating expenses has been approved for recovery in current customer delivery rates.

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 4 to the Corporation's 2009 annual audited consolidated financial statements.

($ millions)	As at September 30, 2010	As at December 31, 2009 (Note 22)
Regulatory Assets		
Future income taxes	**584**	545
Rate stabilization accounts - Terasen Gas companies	**189**	82
Rate stabilization accounts - electric utilities	**50**	68
Regulatory other post-employment benefit ("OPEB") plan asset	**64**	59
Alberta Electric System Operator ("AESO") charges deferral	**49**	80
Point Lepreau [(1)] replacement energy deferral	**41**	23
Accrued 2010 customer rate revenue at FortisAlberta	**27**	-
Income taxes recoverable on OPEB plans	**18**	18
Energy management costs	**18**	14
Deferred development costs for capital [(2)]	**12**	7
Deferred losses on disposal of utility capital assets (Note 2(ii))	**11**	-
Deferred operating costs - FortisAlberta	**8**	-
Deferred costs - smart meters - FortisOntario	**7**	4
Lease costs	**6**	6
Deferred pension costs	**5**	6
Southern Crossing Pipeline tax reassessment (Note 20)	**1**	7
Other regulatory assets	**38**	51
Total Regulatory Assets	**1,128**	970
Less: Current Portion	**(299)**	(223)
Long-Term Regulatory Assets	**829**	747

(1) New Brunswick Power Point Lepreau Nuclear Generating Station

(2) During the third quarter of 2010, approximately $5 million ($4 million after tax) was deferred as a regulatory asset associated with the regulator-approved reversal of most of the project cost overrun previously expensed by TGWI in the fourth quarter of 2009 associated with the conversion of Whistler customer appliances from propane to natural gas.

($ millions)	As at September 30, 2010	As at December 31, 2009 (Note 22)
Regulatory Liabilities		
Future asset removal and site restoration provision	**338**	326
Future income taxes	**34**	35
Rate stabilization accounts - Terasen Gas companies	**48**	44
Rate stabilization accounts - electric utilities	**35**	21
Performance-based rate-setting incentive liabilities	**9**	15
Unrecognized net gains on disposal of utility capital assets [(1)]	**8**	8
Unbilled revenue liability	**7**	10
Southern Crossing Pipeline deferral	**7**	9
Deferred interest	**7**	7
Other regulatory liabilities	**27**	22
Total Regulatory Liabilities	**520**	497
Less: Current Portion	**(45)**	(53)
Long-Term Regulatory Liabilities	**475**	444

(1) Relates to amounts accumulated at the Terasen Gas companies prior to January 1, 2010 and, as approved by the regulator, reallocated from accumulated amortization for future settlement with customers (Note 2 (ii))

6. INVENTORIES

($ millions)	As at **September 30, 2010**	 December 31, 2009
Gas in storage	**182**	159
Materials and supplies	**20**	19
	202	178

During the three and nine months ended September 30, 2010, inventories of $90 million and $586 million, respectively, were expensed and reported in energy supply costs in the interim consolidated statement of earnings ($98 million and $722 million for the three and nine months ended September 30, 2009, respectively). Inventories expensed to operating expenses were $3 million and $10 million for the three and nine months ended September 30, 2010, respectively ($3 million and $10 million for the three and nine months ended September 30, 2009, respectively). Included in inventories expensed to operating expenses was food and beverage costs at Fortis Properties of $2 million and $7 million for the three and nine months ended September 30, 2010, respectively ($2 million and $6 million for the three and nine months ended September 30, 2009, respectively).

7. LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS

($ millions)	As at **September 30, 2010**	 December 31, 2009
Long-term debt and capital lease obligations	**5,114**	5,331
Long-term classification of committed credit facilities (Note 19)	**458**	208
Deferred debt financing costs	**(38)**	(39)
Total long-term debt and capital lease obligations	**5,534**	5,500
Less: Current installments of long-term debt and capital lease obligations	**(158)**	(224)
	5,376	5,276

In April 2010, Terasen redeemed in full for cash its $125 million 8.0% Capital Securities with proceeds from borrowings under the Corporation's committed credit facility.

8. COMMON SHARES

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

Issued and Outstanding	As at **September 30, 2010** **Number of Shares *(in thousands)***	 **Amount *($ millions)***	 December 31, 2009 Number of Shares *(in thousands)*	 Amount *($ millions)*
Common shares	**173,579**	**2,555**	171,256	2,497

Common shares issued during the period were as follows:

	Quarter Ended September 30, 2010 **Number of Shares *(in thousands)***	 **Amount *($ millions)***	**Year-to-Date September 30, 2010** **Number of Shares *(in thousands)***	 **Amount *($ millions)***
Balance, beginning of period	**172,865**	**2,537**	**171,256**	**2,497**
Consumer Share Purchase Plan	**11**	**-**	**39**	**1**
Dividend Reinvestment Plan	**534**	**15**	**1,605**	**43**
Employee Share Purchase Plan	**-**	**-**	**193**	**5**
Stock Option Plans	**169**	**3**	**486**	**9**
Balance, end of period	**173,579**	**2,555**	**173,579**	**2,555**

8. COMMON SHARES (cont'd)

Effective June 1, 2010, the Employee Share Purchase Plan ("ESPP") was amended as approved by the Corporation's Board of Directors, such that future shares purchased under the ESPP will be on the open market. The first investment date under this amended ESPP was September 1, 2010.

Earnings per Common Share

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

Diluted earnings per common share are calculated using the treasury stock method for options and the "if-converted" method for convertible securities.

Earnings per common share were as follows:

Quarter Ended September 30

	2010			2009		
	Earnings (*$ millions*)	**Weighted Average Shares (*in millions*)**	**Earnings per Common Share**	Earnings (*$ millions*)	Weighted Average Shares (*in millions*)	Earnings per Common Share
Basic Earnings per Common Share	**45**	**173.2**	**$0.26**	36	170.4	$0.21
Effect of potential dilutive securities:						
Stock options	**-**	**0.9**		-	0.7	
Preference shares (Note 13)	**4**	**11.9**		4	13.9	
Convertible debentures	**1**	**1.4**		1	1.4	
	50	**187.4**		41	186.4	
Deduct anti-dilutive impacts:						
Preference shares	**(4)**	**(11.9)**		(4)	(13.9)	
Convertible debentures	**(1)**	**(1.4)**		(1)	(1.4)	
Diluted Earnings per Common Share	**45**	**174.1**	**$0.26**	36	171.1	$0.21

Year-to-Date September 30

	2010			2009		
	Earnings (*$ millions*)	**Weighted Average Shares (*in millions*)**	**Earnings per Common Share**	Earnings (*$ millions*)	Weighted Average Shares (*in millions*)	Earnings per Common Share
Basic Earnings per Common Share	**200**	**172.4**	**$1.16**	181	170.0	$1.06
Effect of potential dilutive securities:						
Stock options	**-**	**0.9**		-	0.7	
Preference shares (Note 13)	**12**	**11.9**		12	13.9	
Convertible debentures	**2**	**1.4**		2	1.4	
	214	**186.6**		195	186.0	
Deduct anti-dilutive impacts:						
Convertible debentures	**-**	**-**		(2)	(1.4)	
Diluted Earnings per Common Share	**214**	**186.6**	**$1.15**	193	184.6	$1.05

9. PREFERENCE SHARES

In January 2010, the Corporation issued 10 million Cumulative Five-Year Fixed Rate Reset First Preference Shares, Series H ("First Preference Shares, Series H"). The First Preference Shares, Series H were issued at $25.00 per share. The shares are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.0625 per share per annum for each year up to but excluding June 1, 2015. For each five-year period after that date, the holders of First Preference Shares, Series H are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 1.45 per cent.

On each First Preference Shares, Series H Conversion Date, being June 1, 2015 and June 1st every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series H, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series H Conversion Date, the holders of First Preference Shares, Series H, have the option to convert any or all of their First Preference Shares, Series H into an equal number of cumulative redeemable floating rate First Preference Shares, Series I.

The holders of First Preference Shares, Series I will be entitled to receive floating rate cumulative preferential cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada Treasury Bills plus 1.45 per cent.

On each First Preference Shares, Series I Conversion Date, being June 1, 2020 and June 1st every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series I at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On any date after June 1, 2015, that is not a Series I Conversion Date, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series I at a price of $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series I Conversion Date, the holders of First Preference Shares, Series I, have the option to convert any or all of their First Preference Shares, Series I into an equal number of First Preference Shares, Series H.

On any Series H Conversion Date, if the Corporation determines that there would be less than 1 million First Preference Shares, Series H outstanding, such remaining First Preference Shares, Series H will automatically be converted into an equal number of First Preference Shares, Series I. On any Series I Conversion Date, if the Corporation determines that there would be less than 1 million First Preference Shares, Series I outstanding, such remaining First Preference Shares, Series I will automatically be converted into an equal number of First Preference Shares, Series H. However, if such automatic conversions would result in less than 1 million Series I First Preference Shares or less than 1 million Series H First Preference Shares outstanding, then no automatic conversion would take place.

As the First Preference Shares, Series H are not redeemable at the option of the shareholder, they are classified as equity.

10. STOCK-BASED COMPENSATION PLANS

In January 2010, 24,426 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 represents a unit with an underlying value equivalent to the value of one common share of the Corporation.

In March 2010, 60,000 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 2010 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 May 2010, 21,742 PSUs were paid out to the President and CEO of the Corporation at $27.48 per PSU, for a total of approximately $0.6 million. The payout was made upon the three-year maturation period in respect of the PSU grant made in May 2007 and the President and CEO satisfying the payment requirements, as determined by the Human Resources Committee of the Board of Directors.

In March 2010, the Corporation granted 892,744 options to purchase common shares under its 2006 Stock Option Plan at the five-day volume weighted average trading price of $27.36 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 $4.41 per option.

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

Dividend yield (%)	3.66
Expected volatility (%)	25.1
Risk-free interest rate (%)	2.54
Weighted average expected life (years)	4.5

As at September 30, 2010, 5.0 million stock options were outstanding and 2.8 million stock options were vested.

11. ACCUMULATED OTHER COMPREHENSIVE LOSS

Accumulated other comprehensive loss includes unrealized foreign currency translation gains and losses, net of hedging activities, gains and losses on cash flow hedging activities and gains and losses on discontinued cash flow hedging activities as described in Note 2 to the Corporation's 2009 annual audited consolidated financial statements.

	Quarter Ended September 30					
	2010			2009		
($ millions)	**Opening balance July 1**	**Net change**	**Ending balance September 30**	Opening balance July 1	Net change	Ending balance September 30
Unrealized foreign currency translation losses, net of hedging activities and tax	**(74)**	**(10)**	**(84)**	(55)	(19)	(74)
Net (losses) gains on derivative instruments previously discontinued as cash flow hedges, net of tax	**(5)**	**1**	**(4)**	(5)	-	(5)
Accumulated Other Comprehensive Loss	**(79)**	**(9)**	**(88)**	(60)	(19)	(79)

11. ACCUMULATED OTHER COMPREHENSIVE LOSS (cont'd)

	Year-to-Date September 30					
	2010			2009		
($ millions)	**Opening balance January 1**	**Net change**	**Ending balance September 30**	Opening balance January 1	Net change	Ending balance September 30
Unrealized foreign currency translation losses, net of hedging activities and tax	**(78)**	**(6)**	**(84)**	(46)	(28)	(74)
(Losses) gains on derivative instruments designated as cash flow hedges, net of tax	**-**	**-**	**-**	(1)	1	-
Net (losses) gains on derivative instruments previously discontinued as cash flow hedges, net of tax	**(5)**	**1**	**(4)**	(5)	-	(5)
Accumulated Other Comprehensive Loss	**(83)**	**(5)**	**(88)**	(52)	(27)	(79)

12. 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 $10 million for the quarter ended September 30, 2010 ($7 million for the quarter ended September 30, 2009) and $30 million year-to-date September 30, 2010 ($20 million year-to-date September 30, 2009). The cost of providing the defined contribution arrangements and group RRSPs for the quarter ended September 30, 2010 was $3 million ($3 million for the quarter ended September 30, 2009) and $10 million year-to-date September 30, 2010 ($9 million year-to-date September 30, 2009).

13. FINANCE CHARGES

	Quarter Ended September 30		Year-to-Date September 30	
($ millions)	**2010**	2009	**2010**	2009
Interest - Long-term debt and capital lease obligations	**89**	89	**265**	259
- Short-term borrowings and other	**3**	3	**6**	9
Interest charged to construction	**(8)**	(5)	**(17)**	(13)
Dividends on preference shares classified as debt (Note 8)	**4**	4	**12**	12
	88	91	**266**	267

14. 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 September 30		Year-to-Date September 30	
($ millions, except as noted)	**2010**	2009	**2010**	2009
Combined Canadian federal and provincial statutory income tax rate	**32.0%**	33.0%	**32.0%**	33.0%
Statutory income tax rate applied to earnings before corporate taxes	**20**	16	**89**	79
Preference share dividends	**1**	1	**4**	4
Difference between Canadian statutory rate and rates applicable to foreign subsidiaries	**(5)**	(5)	**(12)**	(12)
Difference in Canadian provincial statutory rates applicable to subsidiaries in different Canadian jurisdictions	**(2)**	(1)	**(8)**	(5)
Items capitalized for accounting but expensed for income tax purposes	**(9)**	(7)	**(29)**	(27)
Other	**-**	(2)	**4**	(5)
Corporate taxes	**5**	2	**48**	34
Effective tax rate	**8.3%**	4.3%	**17.4%**	14.3%

As at September 30, 2010, the Corporation had approximately $116 million (December 31, 2009 - $122 million) in non-capital and capital loss carryforwards, of which $16 million (December 31, 2009 - $16 million) has not been recognized in the consolidated financial statements. The non-capital loss carryforwards expire between 2010 and 2030.

15. SEGMENTED INFORMATION

Information by reportable segment is as follows:

	REGULATED							NON-REGULATED				
	Gas Utilities	**Electric Utilities**										
Quarter Ended September 30, 2010 *($ millions)*	**Terasen Gas Companies - Canadian**	Fortis Alberta	Fortis BC	NF Power	Other Canadian [1]	**Total Electric Canadian**	**Electric Caribbean**	**Fortis Generation [2]**	**Fortis Properties**	**Corporate and Other**	**Inter-segment eliminations**	**Consolidated**
Revenue	**206**	109	62	99	87	**357**	**92**	**13**	**60**	**8**	**(16)**	**720**
Energy supply costs	**90**	-	16	50	57	**123**	**57**	**-**	**-**	**-**	**(11)**	**259**
Operating expenses	**66**	33	17	16	11	**77**	**12**	**2**	**38**	**3**	**(2)**	**196**
Amortization	**27**	45	10	12	7	**74**	**9**	**1**	**5**	**1**	**-**	**117**
Operating income	**23**	31	19	21	12	**83**	**14**	**10**	**17**	**4**	**(3)**	**148**
Finance charges	**28**	12	7	9	5	**33**	**4**	**-**	**6**	**20**	**(3)**	**88**
Corporate tax expense (recovery)	**-**	-	1	4	2	**7**	**(1)**	**1**	**2**	**(4)**	**-**	**5**
Net (loss) earnings	**(5)**	19	11	8	5	**43**	**11**	**9**	**9**	**(12)**	**-**	**55**
Non-controlling interests	**-**	-	-	-	-	**-**	**3**	**-**	**-**	**-**	**-**	**3**
Preference share dividends	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**7**	**-**	**7**
Net (loss) earnings attributable to common equity shareholders	**(5)**	19	11	8	5	**43**	**8**	**9**	**9**	**(19)**	**-**	**45**
Goodwill	**908**	227	221	-	63	**511**	**138**	**-**	**-**	**-**	**-**	**1,557**
Identifiable assets	**4,168**	2,069	1,220	1,182	632	**5,103**	**808**	**193**	**580**	**108**	**(9)**	**10,951**
Total assets	**5,076**	2,296	1,441	1,182	695	**5,614**	**946**	**193**	**580**	**108**	**(9)**	**12,508**
Gross capital expenditures [3]	**72**	102	36	20	12	**170**	**17**	**4**	**5**	**-**	**-**	**268**
Quarter Ended September 30, 2009 *($ millions)*												
Revenue	**208**	84	57	93	70	**304**	**90**	**8**	**60**	**8**	**(13)**	**665**
Energy supply costs	**98**	-	15	50	46	**111**	**52**	**-**	**-**	**-**	**(8)**	**253**
Operating expenses	**60**	33	16	12	8	**69**	**14**	**2**	**37**	**2**	**(1)**	**183**
Amortization	**25**	25	9	11	5	**50**	**9**	**1**	**4**	**2**	**-**	**91**
Operating income	**25**	26	17	20	11	**74**	**15**	**5**	**19**	**4**	**(4)**	**138**
Finance charges	**30**	12	8	9	4	**33**	**4**	**1**	**6**	**21**	**(4)**	**91**
Corporate tax expense (recovery)	**(2)**	(1)	-	4	2	**5**	**-**	**-**	**4**	**(5)**	**-**	**2**
Net (loss) earnings	**(3)**	15	9	7	5	**36**	**11**	**4**	**9**	**(12)**	**-**	**45**
Non-controlling interests	**-**	-	-	-	-	**-**	**4**	**-**	**-**	**-**	**-**	**4**
Preference share dividends	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**5**	**-**	**5**
Net (loss) earnings attributable to common equity shareholders	**(3)**	15	9	7	5	**36**	**7**	**4**	**9**	**(17)**	**-**	**36**
Goodwill	**908**	227	221	-	63	**511**	**144**	**-**	**-**	**-**	**-**	**1,563**
Identifiable assets	**3,840**	1,814	1,122	1,156	534	**4,626**	**803**	**187**	**574**	**149**	**(15)**	**10,164**
Total assets	**4,748**	2,041	1,343	1,156	597	**5,137**	**947**	**187**	**574**	**149**	**(15)**	**11,727**
Gross capital expenditures [3]	**62**	109	30	20	10	**169**	**27**	**2**	**6**	**1**	**-**	**267**

(1) Includes Algoma Power from October 2009, the date of acquisition by FortisOntario

(2) Results reflect contribution from the Vaca hydroelectric generating facility in Belize which was commissioned in March 2010.

(3) Relates to utility capital assets, including amounts for AESO transmision capital projects, and to income producing properties and intangible assets, as reflected in the consolidated statements of cash flows

15. SEGMENTED INFORMATION (cont'd)

	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
Year-to-Date September 30, 2010 *($ millions)*	**Terasen Gas Companies - Canadian**	Fortis Alberta	Fortis BC	NF Power	Other Canadian [1]	**Total Electric Canadian**	**Electric Caribbean**	**Fortis Generation [2]**	**Fortis Properties**	**Corporate and Other**	**Inter-segment eliminations**	**Consolidated**
Revenue	**1,067**	289	193	403	244	**1,129**	**251**	**26**	**169**	**23**	**(38)**	**2,627**
Energy supply costs	**586**	-	50	256	156	**462**	**149**	**1**	**-**	**-**	**(20)**	**1,178**
Operating expenses	**201**	104	53	47	33	**237**	**35**	**6**	**113**	**13**	**(5)**	**600**
Amortization	**81**	94	31	35	18	**178**	**27**	**3**	**13**	**5**	**-**	**307**
Operating income	**199**	91	59	65	37	**252**	**40**	**16**	**43**	**5**	**(13)**	**542**
Finance charges	**84**	40	23	27	16	**106**	**13**	**-**	**18**	**58**	**(13)**	**266**
Corporate tax expense (recovery)	**30**	-	3	12	7	**22**	**1**	**2**	**6**	**(13)**	**-**	**48**
Net earnings (loss)	**85**	51	33	26	14	**124**	**26**	**14**	**19**	**(40)**	**-**	**228**
Non-controlling interests	**-**	-	-	-	-	**-**	**7**	**-**	**-**	**-**	**-**	**7**
Preference share dividends	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**21**	**-**	**21**
Net earnings (loss) attributable to common equity shareholders	**85**	51	33	26	14	**124**	**19**	**14**	**19**	**(61)**	**-**	**200**
Goodwill	**908**	227	221	-	63	**511**	**138**	**-**	**-**	**-**	**-**	**1,557**
Identifiable assets	**4,168**	2,069	1,220	1,182	632	**5,103**	**808**	**193**	**580**	**108**	**(9)**	**10,951**
Total assets	**5,076**	2,296	1,441	1,182	695	**5,614**	**946**	**193**	**580**	**108**	**(9)**	**12,508**
Gross capital expenditures [3]	**182**	258	99	56	33	**446**	**53**	**7**	**14**	**1**	**-**	**703**

Year-to-Date September 30, 2009 *($ millions)*	**Terasen Gas Companies - Canadian**	Fortis Alberta	Fortis BC	NF Power	Other Canadian [1]	**Total Electric Canadian**	**Electric Caribbean**	**Fortis Generation [2]**	**Fortis Properties**	**Corporate and Other**	**Inter-segment eliminations**	**Consolidated**
Revenue	**1,166**	245	184	381	205	**1,015**	**255**	**34**	**165**	**21**	**(33)**	**2,623**
Energy supply costs	**722**	-	50	246	133	**429**	**142**	**2**	**-**	**-**	**(16)**	**1,279**
Operating expenses	**189**	98	51	39	25	**213**	**42**	**8**	**109**	**9**	**(5)**	**565**
Amortization	**76**	70	28	34	14	**146**	**30**	**4**	**12**	**6**	**-**	**274**
Operating income	**179**	77	55	62	33	**227**	**41**	**20**	**44**	**6**	**(12)**	**505**
Finance charges	**91**	36	23	26	13	**98**	**12**	**3**	**17**	**58**	**(12)**	**267**
Corporate tax expense (recovery)	**19**	(4)	3	12	7	**18**	**1**	**2**	**8**	**(14)**	**-**	**34**
Net earnings (loss)	**69**	45	29	24	13	**111**	**28**	**15**	**19**	**(38)**	**-**	**204**
Non-controlling interests	**-**	-	-	-	-	**-**	**8**	**1**	**-**	**-**	**-**	**9**
Preference share dividends	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**14**	**-**	**14**
Net earnings (loss) attributable to common equity shareholders	**69**	45	29	24	13	**111**	**20**	**14**	**19**	**(52)**	**-**	**181**
Goodwill	**908**	227	221	-	63	**511**	**144**	**-**	**-**	**-**	**-**	**1,563**
Identifiable assets	**3,840**	1,814	1,122	1,156	534	**4,626**	**803**	**187**	**574**	**149**	**(15)**	**10,164**
Total assets	**4,748**	2,041	1,343	1,156	597	**5,137**	**947**	**187**	**574**	**149**	**(15)**	**11,727**
Gross capital expenditures [3]	**176**	315	79	52	33	**479**	**77**	**14**	**16**	**1**	**-**	**763**

[1] Includes Algoma Power from October 2009, the date of acquisition by FortisOntario

[2] Results reflect the expiry, on April 30, 2009, at the end of a 100-year term, of the 75 MW of water-right entitlement associated with the Rankine hydroelectric generating facility at Niagara Falls. Results also reflect contribution from the Vaca hydroelectric generating facility in Belize which was commissioned in March 2010.

[3] Relates to utility capital assets, including amounts for AESO transmision capital projects, and to income producing properties and intangible assets, as reflected in the consolidated statements of cash flows

15. 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 the sale of energy from Fortis Generation to Belize Electricity and FortisOntario, electricity sales from Newfoundland Power to Fortis Properties and finance charges on inter-segment borrowings. The significant inter-segment transactions for the three and nine months ended September 30, 2010 and 2009 were as follows.

Significant Inter-Segment Transactions	**Quarter Ended September 30**		**Year-to-date September 30**	
($ millions)	**2010**	2009	**2010**	2009
Sales from Fortis Generation to Regulated Electric Utilities – Caribbean	**11**	7	**19**	15
Sales from Fortis Generation to Other Canadian Electric Utilities	**-**	-	**1**	1
Sales from Newfoundland Power to Fortis Properties	**1**	1	**3**	3
Inter-segment finance charges on borrowings from:				
Corporate to Regulated Electric Utilities – Canadian	**-**	-	**-**	1
Corporate to Regulated Electric Utilities – Caribbean	**-**	1	**2**	2
Corporate to Fortis Generation	**1**	1	**3**	3
Corporate to Fortis Properties	**2**	2	**8**	6

16. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

	Quarter Ended September 30		**Year-to-date September 30**	
($ millions)	**2010**	2009	**2010**	2009
Interest paid	**90**	88	**284**	272
Income taxes paid	**9**	2	**46**	82

17. 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 with proceeds from common and preference share issuances. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 40 per cent equity, including preference shares, and 60 per cent 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 utility's customer rates.

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

	As at			
	September 30, 2010		December 31, 2009	
	($ millions)	***(%)***	*($ millions)*	*(%)*
Total debt and capital lease obligations (net of cash) [(1)]	**5,811**	**58.2**	5,830	60.2
Preference shares [(2)]	**912**	**9.2**	667	6.9
Common shareholders' equity	**3,255**	**32.6**	3,193	32.9
Total [(3)]	**9,978**	**100.0**	9,690	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

17. CAPITAL MANAGEMENT (cont'd)

Certain of the Corporation's long-term debt obligations have covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 70 per cent of the Corporation's consolidated capital structure, as defined by the long-term debt agreements. As at September 30, 2010, the Corporation and its subsidiaries, except for certain debt at Belize Electricity and the Exploits Partnership, as described below, were in compliance with their debt covenants.

As a result of the regulator's Final Decision on Belize Electricity's 2008/2009 Rate Application in June 2008, Belize Electricity does not meet certain debt covenant financial ratios related to loans with the International Bank for Reconstruction and Development and the Caribbean Development Bank totalling approximately $5 million (BZ$10 million) as at September 30, 2010.

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 $58 million as at September 30, 2010 (December 31, 2009 - $59 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.

The Corporation's credit ratings and consolidated credit facilities are discussed further under "Liquidity Risk" in Note 19.

18. FINANCIAL INSTRUMENTS

Fair Values

There has been no change during the nine months ended September 30, 2010 in the designation of the Corporation's financial instruments from that disclosed in the Corporation's 2009 annual audited consolidated financial statements. The carrying values of financial instruments included in current assets, current liabilities, other assets and other liabilities in the consolidated balance sheets of Fortis approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or the nature of these instruments. The carrying and fair values of the Corporation's consolidated long-term debt and preference shares were as follows:

	As at			
	September 30, 2010		December 31, 2009	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt, including current portion [(1) (2)]	**5,534**	**6,407**	5,502	5,906
Preference shares, classified as debt [(1) (3)]	**320**	**350**	320	348

(1) Carrying value is measured at amortized cost using the effective interest rate method.

(2) Carrying value as at September 30, 2010 excludes unamortized deferred financing costs of $38 million (December 31, 2009 - $39 million) and capital lease obligations of $38 million (December 31, 2009 - $37 million).

(3) Preference shares classified as equity are excluded from the requirements of the CICA Handbook Section 3855, *Financial Instrument, Recognition and Measurement*; however, the estimated fair value of the Corporation's $592 million preference shares classified as equity was $610 million as at September 30, 2010 (December 31, 2009 – carrying value $347 million; fair value $356 million).

18. FINANCIAL INSTRUMENTS (cont'd)

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, 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 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 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					
	September 30, 2010				December, 31, 2009	
Liability	**Term to Maturity *(years)***	**Number of Contracts**	**Carrying Value *($ millions)***	**Estimated Fair Value *($ millions)***	Carrying Value *($ millions)*	Estimated Fair Value *($ millions)*
Interest rate swap [(1) (2)]	**< 1**	**1**	**-**	**-**	-	-
Foreign exchange forward contracts [(3) (4)]	**< 1 to 2**	**2**	**-**	**-**	-	-
Natural gas derivatives: [(3) (5)]						
Swaps and options	**Up to 4**	**206**	**(202)**	**(202)**	(119)	(119)
Gas purchase contract premiums	**Up to 3**	**87**	**(2)**	**(2)**	(3)	(3)

(1) Interest rate swap contract matured in October 2010. The contract had the effect of fixing the rate of interest on the non-revolving credit facilities of Fortis Properties at 5.32 per cent.
(2) The fair value measurements are Level 1, based on the three levels that distinguish the level of pricing observability utilized in measuring fair value.
(3) The fair value measurements are Level 2, based on the three levels that distinguish the level of pricing observability utilized in measuring fair value.
(4) The fair values of the foreign exchange forward contracts were recorded in accounts receivable as at September 30, 2010 and as at December 31, 2009.
(5) The fair values of the natural gas derivatives were recorded in accounts payable as at September 30, 2010 and as at December 31, 2009.

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.

19. 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.

19. FINANCIAL RISK MANAGEMENT (cont'd)

Credit Risk

For cash and cash equivalents, trade and other accounts receivable, and other receivables due from customers, 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 and 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 and, as at September 30, 2010, its gross credit risk exposure was approximately $106 million, representing the projected value of retailer billings over a 60-day period. The Company has reduced its exposure to approximately $2 million by obtaining from the retailers either a cash deposit, bond, letter of credit, 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 Terasen Gas companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments. The Terasen Gas companies are also exposed to credit risk on physical off-system sales. To help mitigate credit risk, the Terasen Gas companies deal with high credit-quality institutions in accordance with established credit-approval practices. The counterparties with which the Terasen Gas companies have significant transactions are A-rated entities or better. The Terasen Gas 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 $17 million as at September 30, 2010 (June 30, 2010 - $17 million; March 31, 2010 - $17 million; December 31, 2009 - $17 million; September 30, 2009 - $17 million), excluding derivative financial instruments recorded in accounts receivable, was as follows:

			As at		
($ millions)	**September 30, 2010**	**June 30, 2010**	March 31, 2010	December 31, 2009	September 30, 2009
Not past due	**399**	**442**	518	527	305
Past due 0-30 days	**29**	**49**	63	52	32
Past due 31-60 days	**9**	**14**	14	8	9
Past due 61 days and over	**6**	**11**	9	8	10
	443	**516**	604	595	356

As at September 30, 2010, other receivables due from customers of $6 million (included in other assets) will be received over the next five years and, thereafter, with $1 million expected to be received in year 1, $3 million over years 2 and 3, $1 million over years 4 and 5 and $1 million due after 5 years.

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.

19. FINANCIAL RISK MANAGEMENT (cont'd)

Liquidity Risk (cont'd)

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 September 30, 2010, average annual consolidated long-term debt maturities and repayments over the next five years are expected to be approximately $320 million. 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 at September 30, 2010, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.1 billion, of which $1.2 billion was unused. The credit facilities are syndicated almost entirely with the seven largest Canadian banks, with no one bank holding more than 25 per cent 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	**September 30, 2010**	December 31, 2009
Total credit facilities	645	1,453	13	**2,111**	2,153
Credit facilities utilized:					
Short-term borrowings	-	(340)	(1)	**(341)**	(415)
Long-term debt (including current portion) (Note 7)	(214)	(244)	-	**(458)**	(208)
Letters of credit outstanding	(1)	(111)	-	**(112)**	(100)
Credit facilities unused	430	758	12	**1,200**	1,430

As at September 30, 2010 and December 31, 2009, 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 2010, Maritime Electric renewed its $50 million unsecured committed revolving credit facility, which matures annually in March. During the second quarter of 2010, Maritime Electric increased its unsecured committed revolving credit facility by $10 million.

In April 2010, FortisBC amended its credit facility agreement obtaining an extension to the maturity of its $150 million unsecured committed revolving credit facility with $100 million now maturing in May 2013 and $50 million now maturing in May 2011.

In May 2010, TGVI entered into a two-year $300 million unsecured committed revolving credit facility to replace its $350 million credit facility that was due to mature in January 2011. The terms of the new $300 million credit facility are substantially similar to the terms of the former $350 million credit facility, but there is an increase in pricing reflecting current general market conditions.

In August 2010, Newfoundland Power renegotiated and amended its $100 million unsecured committed credit facility obtaining an extension to the maturity of the facility to August 2013 from August 2011. The amended credit facility agreement reflects an increase in pricing due to current general market conditions 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.

19. FINANCIAL RISK MANAGEMENT (cont'd)

Liquidity Risk (cont'd)

As at September 30, 2010, the Corporation's credit ratings were as follows:

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

In October 2010, DBRS upgraded the Corporation's unsecured debt credit rating to A(low) from BBB(high).

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 and the significant reduction in external debt at Terasen, the Corporation's strong credit metrics, and the Corporation's demonstrated ability and continued focus of 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 September 30, 2010.

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	341	-	-	-	**341**
Trade and other accounts payable	622	-	-	-	**622**
Natural gas derivatives [(1)]	131	60	10	-	**201**
Foreign exchange forward contracts [(2)]	9	5	-	-	**14**
Dividends payable	52	-	-	-	**52**
Customer deposits [(3)]	1	2	1	2	**6**
Long-term debt, including current portion [(4)]	155	594	839	3,946	**5,534**
Interest obligations on long-term debt	329	639	589	4,502	**6,059**
Preference shares, classified as debt	-	123	-	197	**320**
Preference share dividend obligations classified as finance charges	17	33	19	10	**79**
	1,657	1,456	1,458	8,657	**13,228**

(1) Amounts disclosed are on a gross cash flow basis. The derivatives were recorded in accounts payable at fair value as at September 30, 2010 at $204 million.
(2) Amounts disclosed are on a gross cash flow basis. The contracts were recorded in accounts receivable at fair value as at September 30, 2010 at less than $1 million.
(3) Customer deposits were recorded in other liabilities as at September 30, 2010.
(4) Excludes deferred financing costs of $38 million and capital lease obligations of $38 million

Market Risk

Foreign Exchange Risk
The Corporation's earnings from, and net investment 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. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars or a currency pegged to the US dollar. Belize Electricity's reporting currency is the Belizean dollar while the reporting currency of Caribbean Utilities, Fortis Turks and Caicos, FortisUS Energy Corporation and Belize Electric Company Limited is the US dollar. The Belizean dollar is pegged to the US dollar at BZ$2.00=US$1.00.

19. FINANCIAL RISK MANAGEMENT (cont'd)

Market Risk (cont'd)

Foreign Exchange Risk (cont'd)
As at September 30, 2010, the Corporation's corporately issued US$390 million (December 31, 2009 - US$390 million) long-term debt had been designated as a hedge of a portion of the Corporation's foreign net investments. As at September 30, 2010, the Corporation had approximately US$199 million (December 31, 2009 – US$174 million) in foreign net investments remaining to be hedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately held US dollar borrowings that are designated as hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the foreign net investments, which are also recorded in other comprehensive income.

TGI and TGVI'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. TGI and TGVI 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.

As at September 30, 2010, Fortis Properties was party to one interest rate swap agreement that effectively fixed the interest rate on variable-rate borrowings. The interest rate swap agreement matured in October 2010.

The Terasen Gas companies and FortisBC 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 Terasen Gas companies are exposed to commodity price risk associated with changes in the market price of natural gas. This risk is minimized by entering into natural gas derivatives that effectively fix the price of natural gas purchases. The price risk-management strategy of the Terasen Gas 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 natural gas derivatives are recorded 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. 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 2009 annual audited consolidated financial statements, except as described below.

20. CONTINGENT LIABILITIES AND COMMITMENTS (cont'd)

Terasen
TGI had disputed a $7 million assessment of British Columbia Social Services Tax representing additional provincial sales tax and interest on the Southern Crossing Pipeline, which was completed in 2000. The amount was paid in full in 2006 to avoid the accrual of further interest and was recorded as a long-term regulatory deferral asset (Note 5). TGI was successful in its appeal to the British Columbia Court of Appeal, which took place in May 2010. During the third quarter of 2010, TGI received a refund of the majority of the balance with the amount withheld relating to a separate reassessment.

In 2009, Terasen was named, along with other defendants, in an action related to damages to property and chattels, including contamination to sewer lines and costs associated with remediation, related to the rupture in July 2007 of an oil pipeline owned and operated by Kinder Morgan. Terasen has filed a statement of defence but the claim is in its early stages. During the second quarter of 2010, Terasen was added as a third party in all of the related actions and all claims are expected to be tried at the same time. The amount and outcome of the actions are indeterminable at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Maritime Electric
In June 2010, Maritime Electric reached a Settlement Agreement with Canada Revenue Agency related to the reassessment of the Company's 1997-2004 taxation years. In the Settlement Agreement, Maritime Electric's treatment of the Energy Cost Adjustment Mechanism was accepted; however, the reassessments with respect to customer rebate adjustments and the Company's settlement payment to New Brunswick Power regarding the write-down of Point Lepreau would stand. During the third quarter of 2010, final reassessments were received and Canada Revenue Agency refunded the Company's $6 million deposit. As ordered by its regulator, the $6 million refund has been applied to the outstanding balance associated with the operation of the Energy Cost Adjustment Mechanism.

Commitments

There were no material changes in the nature and amount of the Corporation's commitments from the commitments disclosed in the Corporation's 2009 annual audited consolidated financial statements.

21. SUBSEQUENT EVENTS

In October 2010, the Corporation, in partnership with Columbia Power Corporation and Columbia Basin Trust ("CPC/CBT"), concluded definitive agreements to construct a 335-megawatt hydroelectric generating facility (the "Waneta Expansion") at an estimated cost of approximately $900 million, and SNC-Lavalin was awarded a contract for approximately $590 million to design and build the Waneta Expansion. The facility is sited adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia. CBC/CBT are both 100 per cent owned corporations of the Government of British Columbia. Fortis owns a 51 per cent interest in the Waneta Expansion and will operate and maintain the non-regulated investment when the facility comes into service, which is expected in spring 2015. Construction is expected to start in November 2010. The Waneta Expansion will be included in the Canal Plant Agreement and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing hydrologic risk associated with the project. The energy, approximately 630 GWh, (and associated capacity required to deliver such energy) for the Waneta Expansion will be sold to BC Hydro under a long-term energy purchase agreement. The surplus capacity, equal to 234 MW on an average annual basis, will be sold to FortisBC under a long-term capacity purchase agreement, which was accepted by the BCUC in September 2010.

In October 2010, FortisAlberta issued 40-year $125 million 4.80% unsecured debentures, the net proceeds of which will be used to repay committed credit facility borrowings that were incurred primarily to finance capital expenditures, and for general corporate purposes.

21. SUBSEQUENT EVENTS (cont'd)

In October 2010, Fortis redeemed its maturing $100 million 7.40% senior unsecured debentures with proceeds from borrowings under the Corporation's committed credit facility.

22. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to comply with current period classifications, the most significant of which related to the Terasen Gas companies and included an $11 million decrease in long-term regulatory assets, a $10 million increase in utility capital assets, a $3 million increase in intangible assets, an $8 million increase in long-term regulatory liabilities, and a $6 million decrease in long-term future income tax liabilities.

Dates – Dividends* and Earnings

Expected Earnings Release Dates

February 10, 2011	May 4, 2011
August 3, 2011	November 3, 2011

Dividend Record Dates

November 12, 2010	February 11, 2011
May 13, 2011	August 12, 2011

Dividend Payment Dates

December 1, 2010	March 1, 2011
June 1, 2011	September 1, 2011

* *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 September 30		
	2010	**2009**
High	**32.39**	26.19
Low	**26.83**	24.00
Close	**31.94**	24.98