FORTIS INC.

Third Quarter 2011

Dear Shareholder:

Fortis achieved third quarter net earnings attributable to common equity shareholders of $58 million, or $0.31 per common share, compared to $45 million, or $0.26 per common share, for the third quarter of 2010. Year-to-date net earnings attributable to common equity shareholders were $233 million, or $1.30 per common share, up $33 million from earnings of $200 million, or $1.16 per common share, for the same period last year.

Results for the quarter reflected the $11 million after-tax, or $0.06 per common share, fee paid to Fortis in July 2011, following upon the termination of the Merger Agreement between Fortis and Central Vermont Public Service Corporation announced on May 30, 2011.

Canadian Regulated Gas Utilities incurred a loss of $3 million compared to a loss of $5 million for the third quarter of 2010. The third quarter is normally a period of lower customer demand due to warmer temperatures. Results improved mainly due to the favourable impact during the third quarter of this year of the timing of operating expenses, which was partially offset by the impact during the third quarter last year of the $4 million after-tax reversal of previously expensed project overrun costs related to the conversion of Whistler customer appliances from propane to natural gas.

Canadian Regulated Electric Utilities contributed earnings of $43 million, comparable to the third quarter of 2010. Increased earnings from Other Regulated Electric Utilities, mainly due to a higher allowed rate of return on common equity at Algoma Power in 2011, were offset by lower earnings from FortisBC Electric as a result of higher effective corporate income taxes and lower capitalized allowance for funds used during construction.

In September 2011 Newfoundland Power received regulatory approval for the sale of 40% of the utility's joint-use poles to Bell Aliant Inc. Proceeds of approximately $46 million from the pole sale were received in October.

Caribbean Regulated Electric Utilities contributed $6 million to earnings compared to $8 million for the third quarter of 2010. There was no earnings contribution from Belize Electricity during the third quarter of 2011 due to the expropriation by the Government of Belize ("GOB") in June 2011 of the Corporation's investment in the utility. Earnings contribution from Belize Electricity during the third quarter last year was approximately $2 million. Fortis has commissioned an independent valuation of its previous investment in Belize Electricity and expects to submit its claim for compensation to the GOB during the fourth quarter of 2011.

Electricity sales at Caribbean Utilities and Fortis Turks and Caicos continue to be impacted by a decline in customer energy consumption resulting from persistent challenging economic conditions in the region, high fuel prices and a declining population. The use of new, more-efficient generating units at Fortis Turks and Caicos has helped to reduce fuel supply costs at the utility during 2011, thereby mitigating the impact of reduced electricity sales.

Non-Regulated Fortis Generation contributed $8 million to earnings compared to $9 million for the third quarter of 2010. The decline in earnings reflected decreased production in Belize due to lower rainfall associated with a longer dry season in 2011.

Fortis Properties delivered earnings of $9 million, comparable to the third quarter of 2010. In October 2011 Fortis Properties acquired the 160-room, full-service Hilton Suites Winnipeg Airport hotel for $25 million.

Corporate and other expenses were $5 million, $14 million lower than the third quarter of 2010. Excluding the $11 million after-tax termination fee paid to Fortis in July 2011, corporate and other expenses were $3 million lower, driven by a favourable foreign exchange gain recognized during the third quarter of 2011.

Cash flow from operating activities was $678 million year to date, up $144 million from $534 million for the same period last year, driven by higher earnings and favourable working capital changes.

Year-to-date 2011, more than $0.5 billion of long-term capital has been raised by Fortis and its subsidiaries. In June and July 2011, Fortis issued approximately 10.3 million common shares for $341 million, the proceeds of which were used to repay borrowings under credit facilities and finance equity injections into the regulated utilities in western Canada and the non-regulated Waneta Expansion Limited Partnership, in support of infrastructure investment, and for general corporate purposes. In October 2011 FortisAlberta issued 30-year $125 million 4.54% unsecured debentures and, mid-2011, Caribbean Utilities issued US$40 million of unsecured notes for terms ranging from 15 to 20 years and at rates ranging from 4.85% to 5.10%. The proceeds of the debt offerings were used to repay borrowings under credit facilities incurred to finance capital expenditures, to finance future capital spending and for general corporate purposes.

During the third quarter, Fortis renegotiated and amended its committed corporate credit facility, increasing the amount available under the facility to $800 million from $600 million and extending the facility's maturity date to 2015 from 2012. FortisAlberta also increased its committed credit facility to $250 million from $200 million and extended the maturity date of the facility to 2015. DBRS also confirmed the Corporation's debt credit rating at A(low).

We are focused on completing our $1.2 billion 2011 capital expenditure program, with planning well underway for a comparable capital program in 2012. Our five-year capital expenditure program to the end of 2015 is forecasted to be $5.7 billion. This investment should drive growth in earnings and dividends.

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

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

Interim Management Discussion and Analysis

For the three and nine months ended September 30, 2011
Dated November 3, 2011

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FORWARD-LOOKING STATEMENT

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

Fortis includes forward-looking information in the MD&A within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to the Corporation's management. The forward-looking information in the MD&A includes, but is not limited to, statements regarding: the expected timing of filing of regulatory applications and of receipt of regulatory decisions; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of cash from operations, borrowings under credit facilities, equity injections from Fortis and long-term debt issues; consolidated forecast gross capital expenditures for 2011 and in total over the five-year period 2011 through 2015; the expectation of little-to-no growth in electricity sales for Caribbean Utilities and Fortis Turks and Caicos during 2012 and 2013; the expectation that the Corporation's significant capital expenditure program should drive growth in earnings and dividends; expected consolidated long-term debt maturities and repayments on average annually over the next five years; except for debt at Exploits River Hydro Partnership ("Exploits Partnership"), the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants during 2011; no expected material adverse credit rating actions in the near term; and the expected impact of the transition to United States generally accepted accounting principles. The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the expectation that the Corporation will receive compensation from the Government of Belize ("GOB") for the fair value of the Corporation's investment in Belize Electricity that was expropriated by the GOB; the expectation that Belize Electric Company Limited ("BECOL") will not be expropriated by the GOB; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no material capital project and financing cost overrun related to the construction of the Waneta hydroelectric generation expansion project; no significant decline in capital spending; no severe and prolonged downturn in economic conditions; sufficient liquidity and capital resources; the continuation of regulator-approved mechanisms to flow through the commodity cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas commodity prices; no significant variability in interest rates; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas supply; the continued *ability to fund defined benefit pension plans; the absence of significant changes in government energy plans and environmental laws that may materially affect the operations and cash flows of the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; maintenance of information technology infrastructure; favourable relations with First Nations; favourable labour relations; and sufficient human resources to deliver service and execute the consolidated capital program. The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory risk; operating and maintenance risks; risk associated with the amount of compensation to be paid to Fortis for its investment in Belize Electricity that was expropriated by the GOB; the timeliness of the receipt of the compensation and the ability of the GOB to pay the compensation owing to Fortis; risk that the GOB may expropriate BECOL; capital project budget overrun, completion and financing risk in the Corporation's non-regulated business; economic conditions; capital resources and liquidity risk; weather and seasonality; commodity price risk; derivative financial instruments and hedging; interest rate risk; counterparty risk; competitiveness of natural gas; natural gas supply; defined benefit pension plan performance and funding requirements; risks related to the development of the FortisBC Energy (Vancouver Island) Inc. franchise; environmental risks; insurance coverage risk; loss of licences and permits; loss of service area; changes in tax legislation; information technology infrastructure; an ultimate resolution of the expropriation of the assets of the Exploits Partnership that differs from what is currently expected by management; an unexpected outcome of legal proceedings currently against the Corporation; relations with First Nations; labour relations; and human resources. For additional information with respect to the Corporation's risk factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and to the heading "Business Risk Management" in the MD&A for the three and nine months ended September 30, 2011 and for the year ended December 31, 2010.*

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

CORPORATE OVERVIEW

Fortis is the largest investor-owned distribution utility in Canada, serving more than 2,000,000 gas and electricity customers. Its regulated holdings include electric utilities in five Canadian provinces and two Caribbean countries and a natural gas utility in British Columbia, Canada. Fortis owns non-regulated generation assets, primarily hydroelectric, across Canada and in Belize and Upper New York State, and hotels and commercial office and retail space in Canada. Year-to-date September 30, 2011, the Corporation's electricity distribution systems met a combined peak demand of approximately 5,031 megawatts ("MW") and its gas distribution system met a peak day demand of 1,210 terajoules ("TJ"). For additional information on the Corporation's business segments, refer to Note 1 to the Corporation's interim unaudited consolidated financial statements for the three and nine months ended September 30, 2011 and to the "Corporate Overview" section of the MD&A for the year ended December 31, 2010.

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

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

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

On June 20, 2011, the Government of Belize ("GOB") enacted legislation leading to the expropriation of the Corporation's investment in Belize Electricity. As a result of no longer controlling the operations of the utility, the Corporation has discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011, and has classified the book value of the previous investment in the utility as a long-term other asset on the consolidated balance sheet of Fortis. As at September 30, 2011, the long-term other asset, including foreign exchange impacts, totalled $120 million.

Fortis has commissioned an independent valuation of its previous investment in Belize Electricity and expects to submit its claim to the GOB for compensation during the fourth quarter of 2011. On October 21, 2011, Fortis commenced an action in the Belize Supreme Court to challenge the legality of the expropriation of its investment in Belize Electricity.

Fortis continues to control and consolidate the financial statements of Belize Electric Company Limited ("BECOL"), the Corporation's indirect wholly owned non-regulated hydroelectric generation subsidiary in Belize. BECOL generates hydroelectricity from three plants with a combined generating capacity of 51 MW located on the Macal River. The entire output of the plants is sold to Belize Electricity under 50-year contracts expiring in 2055 and 2060. Assuming normal hydrological conditions, Belize Electricity purchases BECOL's normalized annual energy production of 240 gigawatt hours ("GWh") at approximately US$0.10 per kilowatt hour, which generally is the lowest-cost energy supply source in the country of Belize. As at September 30, 2011, the book value of the Corporation's investment in BECOL was $159 million. In 2009 the GOB purported to designate BECOL and other independent power producers in Belize as public utility providers. On October 25, 2011, the GOB amended the Constitution of Belize to require majority government ownership of three public utility providers, including Belize Electricity, but excluding BECOL. The Prime Minister of Belize has stated that the GOB has neither the intention nor the resources to expropriate BECOL.

As at October 31, 2011, Belize Electricity owed BECOL US$8 million for overdue energy purchases representing about one-third of BECOL's annual sales to Belize Electricity. In accordance with long-standing agreements, the GOB guarantees the payment of Belize Electricity's obligations to BECOL.

FINANCIAL HIGHLIGHTS

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

Consolidated Financial Highlights (Unaudited)						
Periods Ended September 30		**Quarter**			**Year-to-Date**	
($ millions, except for common share data)	**2011**	2010	Variance	**2011**	2010	Variance
Revenue	**721**	720	1	**2,735**	2,627	108
Energy Supply Costs	**246**	259	(13)	**1,207**	1,178	29
Operating Expenses	**202**	196	6	**627**	600	27
Amortization	**105**	117	(12)	**311**	307	4
Finance Charges	**88**	88	-	**271**	266	5
Corporate Taxes	**12**	5	7	**57**	48	9
Net Earnings	**68**	55	13	**262**	228	34
Net Earnings Attributable to:						
Non-Controlling Interests	**3**	3	-	**7**	7	-
Preference Equity Shareholders	**7**	7	-	**22**	21	1
Common Equity Shareholders	**58**	45	13	**233**	200	33
Net Earnings	**68**	55	13	**262**	228	34
Basic Earnings per Common Share *($)*	**0.31**	0.26	0.05	**1.30**	1.16	0.14
Diluted Earnings per Common Share *($)*	**0.31**	0.26	0.05	**1.29**	1.15	0.14
Weighted Average Number of Common Shares Outstanding *(# millions)*	**186.5**	173.2	13.3	**179.5**	172.4	7.1
Cash Flow from Operating Activities	**151**	129	22	**678**	534	144

Factors Contributing to Quarterly Revenue Variance

Favourable

- The $17 million (US$17.5 million) fee paid to Fortis in July 2011, following upon the termination of a Merger Agreement between Fortis and Central Vermont Public Service Corporation ("CVPS")
- Growth in the number of customers mainly at FortisAlberta
- An increase in gas delivery rates and the base component of electricity rates at several of the regulated utilities, consistent with rate decisions, reflecting ongoing investment in utility infrastructure, higher regulator-approved expenses recoverable from customers, and a higher allowed ROE at Algoma Power
- The flow through in customer electricity rates of overall higher energy supply costs, driven by Caribbean Utilities
- Higher hospitality revenue at Fortis Properties

Unfavourable

- The timing of recording of the favourable cumulative impact of FortisAlberta's 2010 revenue requirements decision. The impact of the rate decision was recorded during the third quarter of 2010 when the decision was received.
- Lower commodity cost of natural gas charged to customers
- Lower gas sales
- The discontinuance of the consolidation method of accounting for Belize Electricity, effective June 20, 2011
- Increased performance-based rate-setting ("PBR") incentive adjustments owing to customers by FortisBC Electric
- 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 Year-to-Date Revenue Variance

Favourable

- The same factors as discussed above for the quarter
- Overall higher electricity sales
- Higher gas sales
- The recognition of $3 million of accrued revenue at FortisAlberta year-to-date 2011 related primarily to the cumulative 2010 and year-to-date 2011 allowed return and recovery of amortization on the additional $22 million in capital expenditures associated with the Automated Metering Project, as approved by the regulator to be included in rate base

Unfavourable

- Lower commodity cost of natural gas charged to customers
- Increased PBR incentive adjustments, as discussed above for the quarter
- The discontinuance of the consolidation method of accounting for Belize Electricity, effective June 20, 2011
- Approximately $15 million associated with unfavourable foreign currency translation

Factors Contributing to Quarterly Energy Supply Costs Variance

Favourable

- Lower commodity cost of natural gas
- Lower gas sales
- The discontinuance of the consolidation method of accounting for Belize Electricity, effective June 20, 2011
- Approximately $3 million associated with favourable foreign currency translation

Unfavourable

- Increased fuel costs at Caribbean Utilities

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

Unfavourable

- Overall higher gas and electricity sales
- Increased fuel costs at Caribbean Utilities

Favourable

- Lower commodity cost of natural gas
- The discontinuance of the consolidation method of accounting for Belize Electricity, effective June 20, 2011
- Lower-than-expected purchased power costs at FortisBC Electric
- Approximately $9 million associated with favourable foreign currency translation

Factors Contributing to Quarterly Operating Expenses Variance

Unfavourable

- Higher operating expenses at Newfoundland Power, mainly due to the regulator-approved change in the accounting treatment for other post-employment benefit ("OPEB") costs
- Wage and general inflationary cost increases
- The regulator-approved reversal in the third quarter of 2010 of $5 million ($4 million after tax) of previously expensed project overrun costs related to the conversion of Whistler customer appliances from propane to natural gas

Favourable

- The discontinuance of the consolidation method of accounting for Belize Electricity, effective June 20, 2011
- Operating costs of approximately $2 million incurred during the third quarter of 2010 at Newfoundland Power as a result of Hurricane Igor
- Lower-than-expected operating expenses for the third quarter of 2011 at the FortisBC Energy companies, due to the timing of spending and capitalization of certain operating expenses during 2011
- Approximately $1 million associated with favourable foreign currency translation

Factors Contributing to Year-to-Date Operating Expenses Variance

Unfavourable

- The same factors as discussed above for the quarter
- Higher operating expenses year to date at the FortisBC Energy companies, due to the timing of spending of certain regulator-approved increased operating expenses during 2011

Favourable

- The discontinuance of the consolidation method of accounting for Belize Electricity, effective June 20, 2011
- Operating costs of approximately $2 million incurred during the third quarter of 2010 at Newfoundland Power as a result of Hurricane Igor
- Higher corporate operating expenses incurred in the first half of 2010 related to business development costs
- Approximately $2 million associated with favourable foreign currency translation

Factors Contributing to Quarterly Amortization Costs Variance

Favourable

- Lower amortization costs at FortisAlberta, due to the timing of recording of the cumulative impact of FortisAlberta's 2010 revenue requirements decision. The impact of the rate decision was recorded during the third quarter of 2010 when the decision was received.
- The discontinuance of the consolidation method of accounting for Belize Electricity, effective June 20, 2011
- Approximately $0.5 million associated with favourable foreign currency translation

Unfavourable

- Continued investment in utility infrastructure and income producing properties, combined with the commissioning of the liquefied natural gas ("LNG") storage facility during the second quarter of 2011

Factors Contributing to Year-to-Date Amortization Costs Variance

Unfavourable

- The same factor as discussed above for the quarter

Favourable

- Reduced amortization costs in 2011 at the FortisBC Energy companies, mainly due to the retirement late in 2010 of certain general plant assets and the amortization in 2011 of a regulatory deferral account
- Regulator-approved increased amortization costs at Newfoundland Power year-to-date 2010, due to approximately $3 million of adjustments related to an amortization study
- The discontinuance of the consolidation method of accounting for Belize Electricity, effective June 20, 2011
- Approximately $2 million associated with favourable foreign currency translation

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

Favourable

- A net foreign exchange gain associated with the previously hedged investment in Belize Electricity
- The refinancing of maturing corporate debt at lower rates
- Higher capitalized allowance for funds used during construction ("AFUDC") year to date, mainly at the FortisBC Energy companies and FortisAlberta

Unfavourable

- Higher debt levels in support of the utilities' capital expenditure programs
- Lower capitalized AFUDC for the quarter, mainly at FortisBC Electric

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

Unfavourable

- Higher proportion of consolidated income earned in taxable jurisdictions
- Lower deductions for income tax purposes compared to accounting purposes

Favourable

- Lower statutory income tax rates

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

Favourable

- The $11 million after-tax fee paid to Fortis in July 2011, following upon the termination of the Merger Agreement between Fortis and CVPS
- An approximate $6 million and $17 million earnings impact for the quarter and year to date, respectively, related to rate base growth, mainly at the regulated utilities in western Canada, due to continued investment in utility infrastructure
- A net foreign exchange gain of approximately $2.5 million after tax, associated with the previously hedged investment in Belize Electricity
- Higher corporate operating expenses incurred in the first half of 2010 related to business development costs
- The cumulative allowed return and recovery of amortization of approximately $1.5 million, relating to 2010, on the additional capital expenditures at FortisAlberta included in rate base associated with the Automated Metering Project, as discussed above, as recorded in the second quarter of 2011
- Overall higher electricity sales year to date, and growth in the number of customers at FortisAlberta
- Higher capitalized AFUDC year to date, mainly at the FortisBC Energy companies and FortisAlberta
- Lower-than-expected operating costs for the third quarter of 2011 at the FortisBC Energy companies, due to the timing of spending and capitalization of certain operating expenses during 2011
- Lower-than-expected purchased power costs at FortisBC Electric year to date
- A higher allowed ROE at Algoma Power

Unfavourable

- The regulator-approved reversal in the third quarter of 2010 of $4 million after tax of previously expensed project overrun costs related to the conversion of Whistler customer appliances from propane to natural gas
- Higher operating expenses at the FortisBC Energy companies year-to-date 2011, due to the timing of spending of certain regulator-approved increased operating expenses during 2011
- The discontinuance of the consolidation method of accounting for Belize Electricity, effective June 20, 2011. There was no earnings contribution from Belize Electricity year-to-date 2011, while the company contributed approximately $2 million in earnings for each of the third quarter and year-to-date period in 2010.
- Decreased earnings from non-regulated hydroelectric generation operations, mainly reflecting decreased production at BECOL due to lower rainfall
- Lower capitalized AFUDC for the quarter, mainly at FortisBC Electric
- The timing of recording the 2010 revenue requirements decision at FortisAlberta. The favourable cumulative impact of the decision was recorded during the third quarter of 2010 when the decision was received.
- Approximately $1 million for the quarter and $1.5 million year to date associated with unfavourable foreign currency translation

SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders (Unaudited)						
Periods Ended September 30	Quarter			Year-to-Date		
($ millions)	**2011**	2010	Variance	**2011**	2010	Variance
Regulated Gas Utilities - Canadian						
FortisBC Energy Companies	**(3)**	(5)	2	**88**	85	3
Regulated Electric Utilities - Canadian						
FortisAlberta	***19***	*19*	*-*	***59***	*51*	*8*
FortisBC Electric	***10***	*11*	*(1)*	***38***	*33*	*5*
Newfoundland Power	***8***	*8*	*-*	***26***	*26*	*-*
Other Canadian Electric Utilities	***6***	*5*	*1*	***18***	*14*	*4*
	43	43	-	**141**	124	17
Regulated Electric Utilities - Caribbean	**6**	8	(2)	**16**	19	(3)
Non-Regulated - Fortis Generation	**8**	9	(1)	**13**	14	(1)
Non-Regulated - Fortis Properties	**9**	9	-	**18**	19	(1)
Corporate and Other	**(5)**	(19)	14	**(43)**	(61)	18
Net Earnings Attributable to Common Equity Shareholders	**58**	45	13	**233**	200	33

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

REGULATED GAS UTILITIES - CANADIAN

FORTISBC ENERGY COMPANIES [(1)]

Gas Volumes by Major Customer Category (Unaudited)						
Periods Ended September 30	Quarter			Year-to-Date		
(TJ)	**2011**	2010	Variance	**2011**	2010	Variance
Core – Residential and Commercial	**10,560**	12,342	(1,782)	**85,959**	76,600	9,359
Industrial	**820**	840	(20)	**3,937**	3,708	229
Total Sales Volumes	**11,380**	13,182	(1,802)	**89,896**	80,308	9,588
Transportation Volumes	**11,858**	11,458	400	**49,072**	41,958	7,114
Throughput under Fixed Revenue Contracts	**69**	3,592	(3,523)	**1,034**	10,358	(9,324)
Total Gas Volumes	**23,307**	28,232	(4,925)	**140,002**	132,624	7,378

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

Factors Contributing to Quarterly Gas Volumes Variances

Unfavourable

- Lower volumes under fixed revenue contracts, mainly due to higher precipitation, which made it more cost efficient for a large customer to not utilize its natural gas-powered generating facility for significant periods during 2011
- Lower average consumption by residential and commercial customers as a result of warmer weather

Favourable

- Higher transportation volumes reflecting improving economic conditions favourably affecting the forestry and mining sectors and some mining customers burning more natural gas due to a shortage of coal

Factors Contributing to Year-to-Date Gas Volumes Variances

Favourable

- Higher average consumption by residential and commercial customers as a result of cooler weather for the first half of 2011
- Higher transportation volumes, for the same reasons as discussed above for the quarter

Unfavourable

- Lower volumes under fixed revenue contracts, for the same reason as discussed above for the quarter

Customer additions were 1,965 year-to-date 2011 compared to 3,460 during the same period in 2010. Customer additions decreased due to lower building activity during 2011.

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

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

Financial Highlights (Unaudited)						
Periods Ended September 30	**Quarter**			**Year-to-Date**		
($ millions)	**2011**	2010	Variance	**2011**	2010	Variance
Revenue	198	206	(8)	**1,093**	1,067	26
(Loss) earnings	(3)	(5)	2	**88**	85	3

Factors Contributing to Quarterly Revenue Variance

Unfavourable

- Lower commodity cost of natural gas charged to customers
- Lower average gas consumption by residential and commercial customers, partially offset by higher transportation volumes to forestry and mining customers

Favourable

- An increase in the delivery component of customer rates, mainly due to ongoing investment in utility infrastructure and higher regulator-approved operating expenses recoverable from customers

Factors Contributing to Year-to-Date Revenue Variance

Favourable

- The same factor as discussed above for the quarter
- Higher average gas consumption by residential and commercial customers
- Higher transportation volumes to forestry and mining customers

Unfavourable

- Lower commodity cost of natural gas charged to customers

Factors Contributing to Quarterly Loss Variance

Favourable

- Rate base growth, due to continued investment in utility infrastructure
- Lower-than-expected operating expenses for the third quarter of 2011, due to the timing of spending and capitalization of certain operating expenses during 2011
- Lower effective corporate income taxes reflecting a lower statutory income tax rate

Unfavourable

- The regulator-approved reversal in the third quarter of 2010 of $4 million after tax of previously expensed project overrun costs related to the conversion of Whistler customer appliances from propane to natural gas

Factors Contributing to Year-to-Date Earnings Variance

Favourable

- Rate base growth, due to continued investment in utility infrastructure
- Lower-than-expected amortization costs, mainly due to the retirement late in 2010 of certain general plant assets
- Higher transportation volumes to forestry and mining customers
- Higher capitalized AFUDC
- Lower effective corporate income taxes reflecting a lower statutory income tax rate

Unfavourable

- Higher operating expenses, due to the timing of spending of regulator-approved increased operating expenses during 2011, driven by labour and benefits costs and consulting expenses related to feasibility studies
- The regulator-approved reversal in the third quarter of 2010 of $4 million after tax of previously expensed project overrun costs related to the conversion of Whistler customer appliances from propane to natural gas
- Higher finance charges associated with credit facility borrowings

REGULATED ELECTRIC UTILITIES - CANADIAN

FORTISALBERTA

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended September 30	**2011**	2010	Variance	**2011**	2010	Variance
Energy Deliveries *(GWh)*	**3,911**	3,778	133	**12,135**	11,611	524
Revenue *($ millions)*	**103**	109	(6)	**310**	289	21
Earnings *($ millions)*	**19**	19	-	**59**	51	8

Factors Contributing to Quarterly Energy Deliveries Variance

Favourable

- Higher average consumption by commercial and farm and irrigation customers, due to differences in temperature and rainfall period over period
- Growth in the number of customers, mainly residential and commercial, with the total number of customers increasing by approximately 8,800 quarter over quarter

Unfavourable

- Lower average consumption by residential customers, due to warmer-than-average temperatures, which decreased home-heating load

Factors Contributing to Year-to-Date Energy Deliveries Variance

Favourable

- The same factors as discussed above for the quarter
- Higher average consumption by residential customers due to cooler-than-average temperatures during the first quarter of 2011, which increased home-heating load

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

Factors Contributing to Quarterly Revenue Variance

Unfavourable

- The favourable cumulative impact of the 2010 revenue requirements decision was recorded during the third quarter of 2010 when the decision was received. Approximately $14 million of the total revenue accrued in the third quarter of 2010, as a result of the rate decision, related to the first half of 2010. Most of the rate revenue accrual related to regulator-approved increased amortization, operating costs and interest expense.

Favourable

- A 4.7% increase in base customer electricity distribution rates over 2010 rates, effective January 1, 2011. The increase in base rates was primarily due to ongoing investment in utility infrastructure.
- Growth in the number of customers

Factors Contributing to Year-to-Date Revenue Variance

Favourable

- The 4.7% increase in base customer electricity distribution rates, as discussed above for the quarter
- The recognition of $3 million of accrued revenue year-to-date 2011 related primarily to the cumulative allowed return and recovery of amortization on the additional capital expenditures approved by the regulator to be included in rate base associated with the Automated Metering Project. Approximately $1.5 million of the accrual related to 2010. For further information, refer to the “Material Regulatory Decisions and Applications – FortisAlberta” section of this MD&A.
- Growth in the number of customers

Factors Contributing to Quarterly Earnings Variance

Favourable

- Rate base growth, due to continued investment in utility infrastructure
- Higher-than-expected customer growth and energy deliveries

Unfavourable

- The timing of recording the 2010 revenue requirements decision. The favourable cumulative impact of the decision was recorded during the third quarter of 2010 when the decision was received.

Factors Contributing to Year-to-Date Earnings Variance

Favourable

- The same factors as discussed above for the quarter
- The cumulative allowed return and recovery of amortization of approximately $1.5 million, relating to 2010, on the additional capital expenditures associated with the Automated Metering Project, as discussed above
- A $1 million gain on the sale of property during the first quarter of 2011
- Higher capitalized AFUDC

In August 2011 FortisAlberta filed a short-form prospectus which contemplates the issuance of up to $500 million senior unsecured debentures over the 25-month period through to September 2013. For further information, refer to the “Subsequent Events” section of this MD&A.

FORTISBC ELECTRIC [1]

Financial Highlights (Unaudited)	Quarter			Year-to-Date		
Periods Ended September 30	**2011**	2010	Variance	**2011**	2010	Variance
Electricity Sales *(GWh)*	**713**	709	4	**2,300**	2,199	101
Revenue *($ millions)*	**67**	62	5	**215**	193	22
Earnings *($ millions)*	**10**	11	(1)	**38**	33	5

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

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

Favourable

- Growth in the number of customers
- Lower average consumption during the first quarter of 2010, due to warmer-than-average temperatures experienced during that period, resulting in higher electricity sales year to date

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

Favourable

- A 6.6% increase in customer electricity rates, effective January 1, 2011, mainly reflecting ongoing investment in utility infrastructure
- A refundable interim 1.4% and a 2.9% increase in customer electricity rates, effective June 1, 2011 and September 1, 2010, respectively, as a result of the flow through to customers of increased purchased power costs charged to FortisBC Electric by BC Hydro
- The 0.6% and 4.6% increase in electricity sales for the quarter and year to date, respectively
- Higher revenue contribution from non-regulated operating, maintenance and management services
- Higher wheeling revenue year to date

Unfavourable

- Higher-than-expected PBR incentive adjustments owing to customers
- Lower surplus electricity sales

Factors Contributing to Quarterly Earnings Variance

Unfavourable

- Lower capitalized AFUDC, due to fewer assets under construction during 2011
- Higher effective corporate income taxes, mainly due to lower deductions for income tax purposes compared to accounting purposes

Favourable

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

Factors Contributing to Year-to-Date Earnings Variance

Favourable

- Rate base growth, for the same reason as discussed above for the quarter
- Lower-than-expected energy supply costs primarily due to lower average market-priced purchased power costs, partially offset by the related incentive owing back to customers
- Lower-than-expected average consumption in the first quarter of 2010, for the same reason discussed above

Unfavourable

- The same factors as discussed above for the quarter

NEWFOUNDLAND POWER

Financial Highlights (Unaudited)	Quarter			Year-to-Date		
Periods Ended September 30	**2011**	2010	Variance	**2011**	2010	Variance
Electricity Sales *(GWh)*	**923**	916	7	**4,026**	3,931	95
Revenue *($ millions)*	**101**	99	2	**417**	403	14
Earnings *($ millions)*	**8**	8	-	**26**	26	-

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

Favourable

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

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

Favourable

- The 0.8% and 2.4% increase in electricity sales for the quarter and year to date, respectively
- An overall average 0.8% increase in customer electricity rates, effective January 1, 2011, mainly reflecting higher OPEB costs, partially offset by a decrease in the allowed ROE to 8.38% for 2011, down from 9.00% for 2010

Unfavourable

- Decreased amortization of regulatory liabilities and deferrals, as approved by the regulator
- Lower joint-use pole-related revenue, due to new support structure arrangements with Bell Aliant Inc. ("Bell Aliant"), effective January 1, 2011. For further information, refer to the "Material Regulatory Decisions and Applications – Newfoundland Power" and "Subsequent Events" sections of this MD&A.

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

Favourable

- Electricity sales growth
- Lower effective corporate income taxes, primarily due to a lower statutory income tax rate
- Operating expenses during the third quarter of 2010 included approximately $2 million in additional operating labour and maintenance costs as a result of Hurricane Igor in September 2010

Unfavourable

- The decrease in the allowed ROE, as reflected in customer rates
- Wage and general inflationary cost increases
- Higher employee-related operating expenses

OTHER CANADIAN ELECTRIC UTILITIES [1]

Financial Highlights (Unaudited)	Quarter			Year-to-Date		
Periods Ended September 30	**2011**	2010	Variance	**2011**	2010	Variance
Electricity Sales *(GWh)*	**582**	583	(1)	**1,798**	1,750	48
Revenue *($ millions)*	**88**	87	1	**256**	244	12
Earnings *($ millions)*	**6**	5	1	**18**	14	4

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

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

Favourable

- Growth in the number of residential customers
- Higher average consumption, reflecting colder temperatures in Ontario and on Prince Edward Island ("PEI") during the first half of 2011 compared to the same period of 2010, which increased home-heating load, resulting in increased electricity sales year to date

Unfavourable

- Lower average consumption by industrial customers on PEI due to a reduction in farm crop storage and warehousing activities

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

Favourable

- The 2.7% increase in electricity sales year to date
- An increase in the basic component of customer rates at Maritime Electric associated with the recovery of energy supply costs
- An average 3.8% increase in customer electricity rates at Algoma Power, effective December 1, 2010, reflecting an increase in the allowed ROE to 9.85% for 2011 from 8.57% for 2010 and the use of a forward test year for rate setting
- The flow through in customer electricity rates of higher energy supply costs at FortisOntario for the quarter

Unfavourable

- Lower load demand revenue for the quarter from commercial customers on PEI

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

Favourable

- A higher allowed ROE at Algoma Power and the use of a forward test year for rate setting, as reflected in customer rates for 2011
- Electricity sales growth year to date
- Lower effective corporate income taxes at FortisOntario, primarily due to higher deductions taken for income tax purposes compared to accounting purposes

REGULATED ELECTRIC UTILITIES - CARIBBEAN [(1)]

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended September 30	**2011**	2010	Variance	**2011**	2010	Variance
Average US:CDN Exchange Rate [(2)]	**0.98**	1.04	(0.06)	**0.98**	1.04	(0.06)
Electricity Sales *(GWh)*	**197**	318	(121)	**744**	880	(136)
Revenue *($ millions)*	**73**	92	(19)	**236**	251	(15)
Earnings *($ millions)*	**6**	8	(2)	**16**	19	(3)

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

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

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

Unfavourable
- The impact of the discontinuance of the consolidation method of accounting for Belize Electricity, effective June 20, 2011. For further information, refer to the "Corporate Overview" and "Business Risk Management – Investment in Belize" sections of this MD&A.
- Tempered energy consumption due to persistent challenging economic conditions in the region, a declining population, the high cost of fuel, and the early and extended closure of certain hotel and other commercial customers in the Turks and Caicos Islands resulting from a hurricane in August 2011
- Excluding Belize Electricity, electricity sales decreased 1% for the quarter and 1% year to date

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

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

Unfavourable
- The discontinuance of the consolidation method of accounting for Belize Electricity, effective June 20, 2011
- Approximately $4 million for the quarter and $14 million year to date of 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
- Lower electricity sales

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

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

Unfavourable
- Lower electricity sales
- The discontinuance of the consolidation method of accounting for Belize Electricity, effective June 20, 2011. There was no earnings contribution from Belize Electricity year-to-date 2011, while the Company contributed approximately $2 million in earnings for each of the third quarter and year-to-date period in 2010.
- Approximately $1 million associated with unfavourable foreign currency translation year to date

Favourable
- Lower energy supply costs at Fortis Turks and Caicos, mainly due to more fuel-efficient production realized with the commissioning of new generation units at the utility

NON-REGULATED - FORTIS GENERATION [1]

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended September 30	**2011**	2010	Variance	**2011**	2010	Variance
Energy Sales *(GWh)*	**111**	134	(23)	**277**	290	(13)
Revenue *($ millions)*	**11**	13	(2)	**25**	26	(1)
Earnings *($ millions)*	**8**	9	(1)	**13**	14	(1)

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

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

Unfavourable

- Decreased production in Belize, due to lower rainfall associated with a longer dry season in 2011
- Decreased production in Upper New York State for the quarter, due to a generating plant being out of service

Favourable

- Increased production in Upper New York State and Ontario year to date, driven by higher rainfall

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

Unfavourable

- Decreased production in Belize

Favourable

- Increased production and higher average energy sales rate per megawatt hour ("MWh") in Ontario year to date. The average rate per MWh year-to-date 2011 was $72.35 compared to $42.08 year-to-date 2010. Effective May 1, 2010, energy produced in Ontario is being sold under a fixed-price contract with price indexing. Previously, energy was sold at market rates.
- Increased production in Upper New York State year to date

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

Unfavourable

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

Favourable

- Increased production in Upper New York State year to date
- Increased production and a higher average energy sales rate in Ontario year to date
- Lower administrative operating expenses at Ontario operations year to date
- Lower finance charges associated with operations in Belize

In May 2011 the generator at Moose River's hydroelectric generating facility in Upper New York State sustained electrical damage. Equipment and business interruption insurance have been claimed. The generator is under repair and the facility is expected to be operational again in February 2012.

NON-REGULATED - FORTIS PROPERTIES [(1)]

Financial Highlights (Unaudited) Periods Ended September 30 *($ millions)*	**Quarter** **2011**	 2010	 Variance	**Year-to-Date** **2011**	 2010	 Variance
Hospitality Revenue	**47**	44	3	**123**	120	3
Real Estate Revenue	**16**	16	-	**50**	49	1
Total Revenue	**63**	60	3	**173**	169	4
Earnings	**9**	9	-	**18**	19	(1)

(1) Fortis Properties owns and operates 22 hotels, including the Hilton Suites Winnipeg Airport hotel acquired in October 2011, collectively representing 4,300 rooms in eight Canadian provinces, and approximately 2.7 million square feet of commercial office and retail space primarily in Atlantic Canada.

Factors Contributing to Quarterly Revenue Variance

Favourable

- A 5.9% increase in revenue per available room ("RevPar") at the Hospitality Division to $94.83 for the third quarter of 2011 from $89.54 for the same quarter of 2010. RevPar increased due to an overall 4.5% increase in the average daily room rate combined with an overall 1.4% increase in hotel occupancy. The average daily room rate increased in Atlantic Canada and western Canada, while occupancy increases were achieved in Atlantic Canada and central Canada.
- An increase in the occupancy rate at the Real Estate Division to 94.2% as at September 30, 2011 from 93.7% as at September 30, 2010

Factors Contributing to Year-to-Date Revenue Variance

Favourable

- A 2.1% increase in RevPar at the Hospitality Division to $80.54 year-to-date 2011 from $78.89 year-to-date 2010. RevPar increased due to an overall 2.8% increase in the average daily room rate, partially offset by an overall 0.7% decrease in hotel occupancy. The average daily room rate increased in all regions. Hotel occupancy in western Canada decreased, while occupancy in Atlantic Canada and central Canada increased.
- A $0.5 million gain on the sale of the Viking Mall in rural Newfoundland during the first quarter of 2011
- Rent increases at the Real Estate Division
- The increase in the occupancy rate at the Real Estate Division, as discussed above for the quarter

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

Unfavourable

- Higher corporate administrative expenses
- Higher amortization costs year to date, mainly due to capital investment in the Hospitality Division
- A slight decline in performance at the Hospitality Division year to date, mainly due to lower occupancy at hotels in western Canada, partially offset by overall increased average room rates

Favourable

- Improved performance at the Real Estate Division year to date, reflecting the $0.5 million gain on the sale of the Viking Mall during the first quarter of 2011
- Improved performance at the Hospitality Division for the quarter, driven by overall increased average room rates

CORPORATE AND OTHER [(1)]

Financial Highlights (Unaudited)						
Periods Ended September 30	Quarter			Year-to-Date		
($ millions)	**2011**	2010	Variance	**2011**	2010	Variance
Revenue	**25**	8	17	**40**	23	17
Operating Expenses	**3**	3	-	**7**	13	(6)
Amortization	**2**	1	1	**5**	5	-
Finance Charges [(2)]	**15**	20	(5)	**52**	58	(6)
Corporate Tax Expense (Recovery)	**3**	(4)	7	**(3)**	(13)	10
	2	(12)	14	**(21)**	(40)	19
Preference Share Dividends	**7**	7	-	**22**	21	1
Net Corporate and Other Expenses	**(5)**	(19)	14	**(43)**	(61)	18

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

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

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

Favourable

- The $17 million (US$17.5 million) ($11 million after tax) fee paid to Fortis in July 2011 and recorded in revenue, following upon the termination of a Merger Agreement between Fortis and CVPS
- Reduced operating expenses year to date. Operating expenses were higher during the first half of 2010 due to business development costs incurred during that period.
- Lower finance charges. During the third quarter of 2011, finance charges were reduced by a $7 million foreign exchange gain associated with the translation of the US$88 million long-term other asset representing the book value of the Corporation's former net investment in Belize Electricity. The foreign exchange gain was partially offset by a $5.5 million ($4.5 million after tax) foreign exchange loss associated with the translation of previously hedged US dollar-denominated debt. The favourable net impact to earnings of the above foreign exchange impacts was approximately $2.5 million.
- Finance charges were also lower due to the refinancing of maturing corporate debt at lower rates, the repayment of credit facility borrowings during the quarter with a portion of the proceeds from the common share offering in June and July 2011 and the favourable foreign exchange impact associated with the translation of US dollar-denominated interest expense.

Unfavourable

- Higher preference share dividends year to date, due to the issuance of First Preference Shares, Series H in January 2010

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

REGULATORY HIGHLIGHTS

The nature of regulation and material regulatory decisions and applications associated with each of the Corporation's regulated gas and electric utilities year-to-date 2011 are summarized as follows:

NATURE OF REGULATION

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

NATURE OF REGULATION (cont'd)

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

(1) Effective January 1, 2010. For 2009, the allowed common equity component of capital structure was 35%.
(2) Pre-July 1, 2009
(3) Effective July 1, 2009
(4) Interim pending finalization by the AUC
(5) Effective May 1, 2010. For 2009, effective May 1, the allowed common equity component of capital structure was 43.3%.
(6) Pre-December 1, 2010
(7) Effective December 1, 2010
(8) Amount provided under licence. ROA achieved in 2009 and 2010 was materially lower than the ROA allowed under the licence. Fortis Turks and Caicos filed an Electricity Rate Variance Application in August 2011 requesting a change in the current rate structure and an overall increase in base rates to government and commercial customers of approximately 6%.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS

Regulated Utility	Summary Description
FEI/FEVI/FEWI	• FEI and FEWI review natural gas and propane commodity rates with the BCUC 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 and/or storage capacity. The commodity cost of natural gas and propane and mid-stream costs are flowed through to customers without markup. The delivery rate charged to FEVI customers includes a component to recover approved gas costs and is set annually. In order to ensure that the balance in the Commodity Cost Reconciliation Account is recovered on a timely basis, FEI and FEWI prepare and file quarterly calculations with the BCUC to determine whether customer rate adjustments are needed to reflect prevailing market prices for natural gas and propane. These rate adjustments ignore the temporal effect of derivative valuation adjustments on the balance sheet and, instead, reflect the forward forecast of gas costs over the recovery period. • Effective January 1, 2011, rates for residential customers in the Lower Mainland, Fraser Valley and Interior, North and Kootenay service areas decreased by approximately 6%, as approved by the BCUC, to reflect net changes in delivery, commodity and mid-stream costs. Natural gas commodity rates remained unchanged as of April 1, 2011 and as of July 1, 2011, following the BCUC's quarterly reviews of such rates. • Effective October 1, 2011, rates for residential customers in the Lower Mainland, Fraser Valley and Interior, North and Kootenay service areas decreased by approximately 5% to reflect changes in commodity costs, following the BCUC's quarterly review of such rates. • In December 2010 FEI filed an application with the BCUC to provide fuelling services through FEI-owned and operated compressed natural gas and LNG fuelling stations. In July 2011 FEI received a decision from the BCUC that approved the fuelling station infrastructure along with a long-term contract with one counterparty for the supply of compressed natural gas. The BCUC denied the Company's application for a general tariff for the provision of compressed natural gas and LNG for vehicles, unless certain contractual conditions are met. The Company is considering these proposed amendments in the context of new natural gas vehicle stations. • In July 2011 the BCUC approved the application jointly filed by the FortisBC Energy companies and FortisBC Electric requesting the utilities be permitted to adopt United States generally accepted accounting principles ("US GAAP") effective January 1, 2012 for regulatory reporting purposes. • In July 2011 FEVI received a BCUC decision approving the option for two First Nations bands to invest up to 15% of the equity component of the capital structure of the new LNG storage facility on Vancouver Island. If the option is exercised, the equity investment by the First Nations bands would occur effective January 1, 2012. • In August 2011 FEI and FEVI received a decision from the BCUC on the use of Energy Efficiency and Conservation ("EEC") Funds as incentives for natural gas vehicles ("NGVs"). The companies had made these funds available to assist large customers in purchasing NGVs in lieu of vehicles fueled by diesel. The decision determined that it was not appropriate to use EEC funds for this purpose and the BCUC has requested that the companies provide further submissions to determine the prudency of the EEC incentives at a future time. • In January 2011 FEI filed a report of its review of its Price Risk Management Plan ("PRMP") objectives with the BCUC related to its gas commodity hedging plan and also submitted a revised 2011-2014 PRMP. In July 2011 the BCUC issued its decision on FEI's report and determined that commodity hedging in the current environment was not a cost-effective means of meeting the objectives of price competitiveness and rate stability. The BCUC concurrently denied FEI's 2011-2014 PRMP with the exception of certain elements to address regional price discrepancies. As a result, FEVI and FEI have suspended commodity-hedging activities with the exception of limited swaps as permitted by the BCUC. The existing hedging contracts are expected to continue in effect through to their maturity and the gas utilities' ability to fully recover the commodity cost of gas in customer rates remains unchanged.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FEI / FEVI / FEWI (cont'd)	• In September 2011 the FortisBC Energy companies filed an update to their 2012-2013 Revenue Requirements Applications. FEI has requested an increase in rates of 3.2%, effective for each of January 1, 2012 and January 1, 2013, reflecting an increase in the delivery component of customer rates. FEI's application assumes forecast average rate base of approximately $2,754 million for 2012 and $2,811 million for 2013. FEVI has requested that rates remain unchanged for the two-year period commencing January 1, 2012. FEVI's application assumes forecast average rate base of $788 million for 2012 and $816 million for 2013. FEWI has requested an increase in rates of approximately 6.5% effective January 1, 2012 and approximately 4.3% effective January 1, 2013, reflecting an increase in the delivery component of customer rates. FEWI's application assumes forecast average rate base of $42 million for 2012 and $41 million for 2013. The requested rate increases are driven by ongoing investment in utility infrastructure focused on system integrity and reliability, and forecast increased operating expenses associated with inflation, a heightened focus on safety and security of the natural gas systems and increasing compliance with codes and regulations. A decision on the rate applications is expected late in the first quarter of 2012. • In November 2011 FEI, FEVI and FEWI filed an application with the BCUC for the amalgamation of the three companies into one legal entity, and for the implementation of common rates and services for the utilities' customers across the province of British Columbia, effective January 1, 2013. The amalgamation requires approval by the BCUC and consent of the Government of British Columbia.
FortisBC Electric	• In December 2010 the BCUC approved a Negotiated Settlement Agreement ("NSA") pertaining to FortisBC Electric's 2011 Revenue Requirements Application. The result was a general customer electricity rate increase of 6.6%, effective January 1, 2011. The rate increase was primarily the result of the Company's ongoing investment in utility infrastructure, including increased amortization and interest expense. • In June 2011 FortisBC Electric filed its 2012-2013 Revenue Requirements Application, which included its 2012-2013 Capital Expenditure Plan, and its Integrated System Plan ("ISP"). The ISP includes the Company's Resource Plan, Long-Term Capital Plan and Long-Term Demand Side Management Plan. FortisBC Electric requested an interim 4% increase in customer electricity rates effective January 1, 2012 and a 6.9% increase effective January 1, 2013. The rate increases are due to ongoing investment in utility infrastructure, including increased costs of financing the ongoing investment, and increasing power purchases driven by customer growth and increased demand for electricity. FortisBC Electric's rate application assumes forecast average rate base of approximately $1,145 million for 2012 and $1,212 million for 2013. The requested capital expenditures are $111 million for 2012 and $134 million for 2013, before customer contributions. A decision on the rate application is expected late 2011 or early 2012. • Effective June 1, 2011, the BCUC approved a refundable interim increase of 1.4% in FortisBC Electric customer electricity rates arising from an increase in purchased power costs due to an interim increase in BC Hydro rates.
FortisAlberta	• In December 2010 the AUC issued its decision on FortisAlberta's August 2010 Compliance Filing, which incorporated the AUC's decision, received in July 2010, on the Company's 2010 and 2011 Distribution Tariff Application ("DTA"). The December 2010 decision approved the Company's distribution revenue requirements of $368 million for 2011. Final distribution electricity rates and rate riders were also approved, effective January 1, 2011. • During 2011 the AUC initiated its proceeding to finalize the allowed ROE for 2011, review capital structure and consider whether a return to a formula-based approach for annually setting the allowed ROE, beginning in 2012, is warranted. In the absence of a formula-based approach, the AUC is expected to consider how the allowed ROE will be set for 2012. A hearing on the proceeding has been completed and a decision is expected in the fourth quarter of 2011. • In March 2011 FortisAlberta filed its 2012 and 2013 DTA. The Company requested approval of revenue requirements of $410 million for 2012 and $447 million for 2013, for rate increases of 8.2% and 6.9%, respectively. The DTA also proposes approximately $776 million in gross capital expenditures over the two-year period. The requested rate increases are driven primarily by ongoing investment in utility infrastructure, including increased amortization and interest expense. At FortisAlberta's request, the AUC is allowing FortisAlberta to settle the DTA through negotiation, but has stipulated that the negotiation apply only to 2012 rates.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FortisAlberta (cont'd)	• In June 2011 the AUC issued its decision regarding the prudency of additional capital expenditures above $104 million related to the Company's Automated Metering Project. In its decision, the AUC concluded that the full amount of the forecasted total project cost of $126 million can be included in rate base and collected in customer rates. The impact of the decision was the recognition of $3 million in accrued revenue and an associated regulatory asset as at September 30, 2011. The Utilities Consumer Advocate had filed a Leave to Appeal related to this decision. During the third quarter of 2011, the Leave to Appeal request was withdrawn upon consent of all parties and no further court proceedings remain related to the above matter. • In October 2010 the Central Alberta Rural Electrification Association ("CAREA") filed an application with the AUC seeking a declaration that, effective January 1, 2012, CAREA be entitled to service any new customers wishing to obtain electricity for use on property within CAREA's service area and that FortisAlberta be restricted to serving only those customers that are not being provided service by CAREA. FortisAlberta has intervened in the proceeding. • The AUC has initiated a process to reform utility rate regulation in Alberta. The AUC has expressed its intention to apply a PBR formula to electricity distribution rates. FortisAlberta is currently assessing PBR and will participate fully in the AUC process. In July 2011 FortisAlberta, along with other distribution utilities operating under the AUC's jurisdiction, submitted their PBR proposals to the AUC. The Company's submission outlines its views as to how PBR should be implemented at FortisAlberta.
Newfoundland Power	• In November 2010 the PUB approved Newfoundland Power's application to defer the recovery of expected increased costs in 2011 of $2.4 million, due to expiring regulatory amortizations in 2011. • In December 2010 the PUB approved Newfoundland Power's application to: (i) adopt the accrual method of accounting for OPEB costs, effective January 1, 2011; (ii) recover the transitional regulatory asset balance of approximately $53 million, associated with adoption of accrual accounting, over a 15-year period; and (iii) adopt an OPEB cost-variance deferral account to capture differences between OPEB expense calculated in accordance with GAAP and OPEB expense approved by the PUB for rate-setting purposes. • In December 2010 Newfoundland Power received approval from the PUB for an overall average 0.8% increase in customer electricity rates, effective January 1, 2011, mainly resulting from the PUB's approval for the Company to change its accounting for OPEB costs, as described above, partially offset by the impact of the decrease in the allowed ROE for 2011. • On January 1, 2011, new support structure arrangements with Bell Aliant went into effect, including Bell Aliant buying back 40% of all joint-use poles and related infrastructure from Newfoundland Power representing approximately 5% of the Company's rate base. The new support structure arrangements were subject to certain conditions, including PUB approval of the sale of the joint-use poles. The PUB issued an order approving the sale of the joint-use poles in September 2011. Effective January 1, 2011, Newfoundland Power is no longer receiving pole rental revenue from Bell Aliant. Newfoundland Power is responsible for the construction and maintenance of Bell Aliant's support structure requirements throughout 2011. The new support structure arrangements are not expected to materially impact Newfoundland Power's ability to earn a reasonable return on its rate base in 2011. Proceeds of approximately $46 million from the sale of 40% of the joint-use poles were received by Newfoundland Power from Bell Aliant in October 2011. The final sale price for the poles is subject to adjustment upon completion of a pole survey later in 2011. The sale proceeds were used to pay down credit facility borrowings and pay a special dividend of approximately $30 million to Fortis in order to maintain Newfoundland Power's capital structure at 45% common equity. • In April 2011 the PUB approved Newfoundland Power's application requesting an Optional Seasonal Rate ("OSR") for domestic customers, effective July 1, 2011. The OSR charges a higher price for electricity consumed during the months of December through April and a lower rate during the months of May through November. The PUB also approved capital expenditures for 2011 required to facilitate implementation of the OSR and the use of an OSR Revenue and Cost Recovery Account that provides for the deferral of annual cost and revenue effects associated with implementing the OSR. • Effective July 1, 2011, the PUB approved an overall average increase in customer electricity rates of 7.7%. The increase in rates was primarily due to the normal annual operation of the Rate Stabilization Plan of Newfoundland and Labrador Hydro ("Newfoundland Hydro"). Variances in the cost of fuel used to generate electricity that Newfoundland Hydro sells to Newfoundland Power are captured and flowed through to Newfoundland Power customers through the operation of Newfoundland Power's Rate Stabilization Account. The increase in rates, principally due to increased fuel prices, will have no impact on Newfoundland Power's earnings.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
Newfoundland Power (cont'd)	• In July 2011 Newfoundland Power filed an application with the PUB requesting approval for its 2012 Capital Expenditure Plan totalling approximately $77 million. • In September 2011 Newfoundland Power filed an application with the PUB requesting the deferred recovery of expected increased costs in 2012 of $2.4 million, due to expiring regulatory amortizations in 2012. The application was approved in October 2011. • As part of its 2011 Budget, the Government of Newfoundland and Labrador introduced the Energy Rebate, effective October 1, 2011, in which the 8% provincial portion of the Harmonized Goods and Services Tax on home energy purchases, including electricity, is being refunded to residential customers.
Maritime Electric	• In November 2010 Maritime Electric signed the PEI Energy Accord (the "Accord") with the Government of PEI. The Accord covers the period from March 1, 2011 through February 29, 2016. Under the terms of the Accord, the Government of PEI is assuming responsibility for the cost of incremental replacement energy and the monthly operating and maintenance costs related to the NB Power Point Lepreau Nuclear Generating Station ("Point Lepreau"), effective March 1, 2011 until Point Lepreau is fully refurbished, which is expected by fall 2012. The Government of PEI is financing these costs, which will be recovered from customers. In the event that Point Lepreau does not return to service by fall 2012, the Government of PEI reserves the right to cease the monthly payments. As permitted by IRAC, incremental replacement energy costs incurred during the refurbishment of Point Lepreau up to the end of February 2011 were deferred by Maritime Electric and totalled approximately $47 million. The deferred costs are included in rate base. • The nature and timing of the recovery of the deferred costs related to Point Lepreau is subject to further review by the PEI Energy Commission (the "Commission"), which was recently established by the Government of PEI. Having authority under the *Public Inquiries Act,* the co-chaired five-member Commission's goal is to examine and provide advice on ways in which PEI's cost of electricity can be structurally reduced and/or stabilized over the longer term. In carrying out this goal, the Commission will, amongst other things, examine and provide recommendations on long-term ownership and management of electricity on PEI and provide advice and recommendations as to the future role of the PEI Energy Corporation, IRAC (as it relates to electricity) and the Office of Energy Efficiency. • The Accord also provides for the financing by the Government of PEI of costs associated with Maritime Electric's termination of the Dalhousie Unit Participation Agreement. The costs will be collected from customers over a period to be established by the Government of PEI. As a result of the Accord, including the favourable impact on purchased power costs of the new five-year power purchase agreement between Maritime Electric and NB Power, customer electricity rates decreased overall by approximately 14%, effective March 1, 2011, reflecting a decrease in the Energy Cost Adjustment Mechanism ("ECAM") component of customer rates, partially offset by an increase in the base component of customer rates. A two-year customer rate freeze commenced after the March 1, 2011 rate adjustment.
FortisOntario	• In non-rebasing years, customer electricity distribution rates are set using inflationary factors less an efficiency target under the Third-Generation Incentive Rate Mechanism ("IRM") as prescribed by the OEB. In March 2011 the OEB published the applicable inflationary and efficiency targets, which resulted in minimal changes in base customer electricity distribution rates at FortisOntario's operations in Fort Erie, Gananoque and Port Colborne. • In November 2010 the OEB approved an NSA pertaining to Algoma Power's electricity distribution rate application for customer rates, effective December 1, 2010 through December 31, 2011, using a 2011 forward test year. The rates reflect an approved allowed ROE of 9.85% on a deemed equity component of capital structure of 40%. The overall impact of the OEB rate decision on an average customer's electricity bill was an overall increase of 3.8%, including rate riders and other charges. • The present form of Third-Generation IRM will not accommodate Algoma Power's customer rate structure and the RRRP Program. Algoma Power has consulted with the intervener community to develop a form of incentive rate-making that may be used between rebasing periods. Due to regulations in Ontario associated with the RRRP Program, customer electricity distribution rates at Algoma Power are tied to the average changes in rates of other electric utilities in Ontario. The balance of Algoma Power's revenue requirement is recovered from the RRRP Program. In September 2011 Algoma Power filed its first Third-Generation IRM application for customer electricity distribution rates, effective January 1, 2012. The Third-Generation IRM maintains the allowed ROE at 9.85% for 2012. Algoma Power has proposed that both electricity rates and funding under the RRRP Program be indexed. • During the fourth quarter of 2011, FortisOntario expects to file a Third-Generation IRM application for its operations in Port Colborne and a similar, but harmonized, rate application for its operations in Fort Erie and Gananoque. The Third-Generation IRM maintains the allowed ROE at 8.01% for 2012. The OEB is expected to publish the applicable inflation factor and efficiency targets under the IRM during the first quarter of 2012.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FortisOntario (cont'd)	• FortisOntario expects to file a COS Application in 2012 for harmonized electricity distribution rates in Fort Erie, Port Colborne and Gananoque, effective January 1, 2013, using a 2013 forward test year. The timing of the filing of the COS Application corresponds with the ending of the period that the current Third-Generation IRM applies to FortisOntario.
Caribbean Utilities	• In March 2011 Caribbean Utilities confirmed to the ERA that the RCAM, as provided in the Company's transmission and distribution licence, yielded no customer rate adjustment effective June 1, 2011. • In March 2011 the ERA approved US$134 million of proposed non-generation installation expenditures as requested by Caribbean Utilities in its 2011-2015 Capital Investment Plan ("CIP"). The 2011-2015 CIP was prepared on the basis of the Company's application to the ERA for a delay in any new generation installation until there is more certainty in growth forecasts. The remaining US$85 million of the CIP relates to new generation installation, which would be subject to a competitive solicitation process with the next generating unit currently scheduled for installation in 2014. • In July 2011 the ERA approved Caribbean Utilities request to use US GAAP for regulatory reporting purposes, beginning January 1, 2012. • In August 2011 Caribbean Utilities requested and received expressions of interest and preliminary proposals for the financing, construction, ownership and operation of renewable energy generation facilities. It is the Company's intention to accept up to 13 MW in aggregate of grid-connected renewable energy generators on Grand Cayman. Potential investors would become independent power producers that will enter into power purchase agreements ("PPAs") with the Company for the supply of electricity from the alternative energy generators. The PPAs are subject to ERA review and approval. An evaluation of the expressions of interest received is expected by the end of 2011. • Caribbean Utilities will be filing its 2012-2016 CIP during the fourth quarter of 2011.
Fortis Turks and Caicos	• In March 2011 Fortis Turks and Caicos submitted its 2010 annual regulatory filing outlining the Company's performance in 2010. Included in the filing were the calculations, in accordance with the utility's licence, of rate base of US$142 million for 2010 and cumulative shortfall in achieving allowable profits of US$49 million as at December 31, 2010. • In August 2011 Fortis Turks and Caicos filed with the interim Government of the Turks and Caicos Islands an Electricity Rate Variance Application, which requested a change in the rate structure and an overall approximate 6% increase in base rates to government and commercial customers. A response to the application is expected during the fourth quarter of 2011. • An independent review of the regulatory framework for the electricity sector in the Turks and Caicos Islands was performed during the third quarter of 2011 on behalf of the interim Government of the Turks and Caicos Islands. The purpose of the review was to: (i) assess the effectiveness of the current regulatory framework in terms of its administrative and economic efficiency; (ii) assess the current and proposed electricity costs and tariffs in the Turks and Caicos Islands in relation to comparable regional and international utilities; (iii) make recommendations for a revised regulatory framework and *Electricity Ordinance*; and (iv) make recommendations for the implementation and operation of the revised regulatory framework. • Earlier in 2011, the interim Government of the Turks and Caicos Islands publicly stated its intention to implement a carbon tax, effective September 2011, that would be applicable to Fortis Turks and Caicos but which may not be permitted to be passed on to Fortis Turks and Caicos' customers. To date, no carbon tax has been implemented. Under the terms of an agreement with the Government of the Turks and Caicos Islands when Fortis Turks and Caicos was granted its licence, the Company is exempt from any taxes other than customs duties where applicable by law.

CONSOLIDATED FINANCIAL POSITION

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

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

Balance Sheet Account	Increase / (Decrease) *($ millions)*	Explanation
Accounts receivable	(186)	The decrease was driven by the FortisBC Energy companies, mainly due to a seasonal decrease in sales and the lower commodity cost of natural gas reflected in customer rates.
Regulatory assets – current and long-term	52	The increase was mainly due to an increase in the deferral of: (i) future income taxes; (ii) Alberta Electric System Operator ("AESO") charges and operating costs at FortisAlberta; (iii) various miscellaneous costs as permitted by the regulator at the FortisBC Energy companies; and (iv) fuel costs at Caribbean Utilities. The above increases were partially offset by the deferral at the FortisBC Energy companies associated with the change in the fair market value of the natural gas derivatives, and a decrease in the 2010 accrued distribution revenue adjustment rider at FortisAlberta as it is being collected in 2011 rates.
Inventories	26	The increase was driven by the normal seasonal increase of gas in storage at the FortisBC Energy companies, partially offset by the impact of lower natural gas commodity prices.
Other assets	116	The increase was due to the discontinuance of the consolidation method of accounting for Belize Electricity in June 2011, due to the expropriation of the Company by the GOB, and the resulting classification of the book value of the Corporation's previous investment in Belize Electricity, including reclassified unrealized foreign currency translation losses of $28 million, to long-term other assets.
Utility capital assets	305	The increase primarily related to $747 million invested in electricity and gas systems and the impact of foreign exchange on the translation of US dollar-denominated utility capital assets, partially offset by the impact of the discontinuance of the consolidation method of accounting for Belize Electricity, and amortization costs and customer contributions year-to-date 2011.
Short-term borrowings	(116)	The decrease was driven by lower borrowings at the FortisBC Energy companies, due to seasonality of operations and the repayment of borrowings using proceeds from an equity injection from Fortis.
Accounts payable and accrued charges	(100)	The decrease was mainly due to: (i) the change in the fair market value of the natural gas derivatives at the FortisBC Energy companies; (ii) the timing of payment of property taxes and franchise fees at the FortisBC Energy companies; (iii) lower amounts owing for purchased natural gas at the FortisBC Energy companies and purchased power at Newfoundland Power, associated with seasonality of operations; and (iv) the discontinuance of the consolidation method of accounting for Belize Electricity. The decrease was partially offset by higher payables associated with transmission-connected projects and cost accruals at FortisAlberta and higher accounts payable at the Waneta Expansion Limited Partnership ("Waneta Partnership") associated with the construction of the Waneta hydroelectric generation expansion project ("Waneta Expansion Project").

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

Balance Sheet Account	Increase / (Decrease) *($ millions)*	Explanation
Regulatory liabilities – current and long-term	35	The increase was mainly due to: (i) increased deferrals at the FortisBC Energy companies; (ii) an increase in the provision for asset removal and site restoration costs at FortisAlberta; (iii) increases in the weather normalization and other deferral accounts at Newfoundland Power; and (iv) an increase in the ECAM account at Maritime Electric. The increased deferrals at the FortisBC Energy companies were associated with the Rate Stabilization Deferral Account, reflecting the accumulation of over-recovered costs of providing service to customers during 2011 and the Revenue Stabilization Adjustment Mechanism, reflecting the margin impact of actual gas volumes consumed by residential and commercial customers being in excess of forecast gas volumes. The above increases were partially offset by the impact of the discontinuance of the consolidation method of accounting for Belize Electricity.
Future income tax liabilities – current and long-term	41	The increase was driven by tax timing differences related to capital expenditures at the FortisBC Energy companies, FortisAlberta and FortisBC Electric.
Long-term debt and capital lease obligations (including current portion)	(70)	The decrease was driven by the repayment of the Corporation's committed credit facility borrowings with a portion of the proceeds from the June and July 2011 $341 million common share issue and the discontinuance of the consolidation method of accounting for Belize Electricity. The decrease was partially offset by higher committed credit facility borrowings at FortisAlberta and the issuance of US$40 million of long-term debt by Caribbean Utilities in support of the companies' capital expenditure programs, and the impact of foreign exchange on the translation of US dollar-denominated debt.
Shareholders' equity (before non-controlling interests)	504	The increase was driven by the issuance of $341 million in common shares in June and July 2011. The remainder of the increase in shareholders' equity was primarily due to: (i) the reclassification of $28 million of unrealized foreign currency translation losses related to the Corporation's previous investment in Belize Electricity from accumulated other comprehensive loss to long-term other assets; (ii) net earnings attributable to common equity shareholders year-to-date 2011, less common share dividends; and (iii) the issuance of common shares under the Corporation's dividend reinvestment and stock option plans.
Non-controlling interests	43	The increase was driven by advances from the 49% non-controlling interests in the Waneta Partnership.

LIQUIDITY AND CAPITAL RESOURCES

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

Summary of Consolidated Cash Flows (Unaudited)						
Periods Ended September 30	**Quarter**			**Year-to-Date**		
($ millions)	**2011**	2010	Variance	**2011**	2010	Variance
Cash, Beginning of Period	**298**	71	227	**109**	85	24
Cash Provided by (Used in):						
Operating Activities	**151**	129	22	**678**	534	144
Investing Activities	**(269)**	(253)	(16)	**(756)**	(658)	(98)
Financing Activities	**(73)**	117	(190)	**76**	103	(27)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**1**	-	1	**1**	-	1
Cash, End of Period	**108**	64	44	**108**	64	44

Operating Activities: Cash flow from operating activities, after working capital adjustments, was $22 million higher quarter over quarter and $144 million higher year to date compared to the same period last year. The increases were driven by higher earnings and favourable changes in working capital, partially offset by unfavourable changes in regulatory deferral accounts. The favourable working capital changes were driven by the greater impact of seasonality at the FortisBC Energy companies and an increase in accounts payable and the collection from customers of the 2010 accrued distribution revenue adjustment rider at FortisAlberta, partially offset by unfavourable working capital changes at Maritime Electric. Lower AESO net transmission-related receipts and payments at FortisAlberta had an unfavourable impact on both working capital and regulatory deferral accounts. Changes in regulatory deferral accounts at the FortisBC Energy companies also had an unfavourable impact on cash flow from operating activities quarter over quarter.

Investing Activities: Cash used in investing activities was $16 million higher quarter over quarter mainly due to capital spending related to the non-regulated Waneta Expansion Project, partially offset by lower capital spending at FortisAlberta. Cash used in investing activities was $98 million higher year to date compared to the same period last year due to capital spending related to the non-regulated Waneta Expansion Project, partially offset by lower capital spending at FortisBC Electric and an increase in contributions received in aid of construction.

Financing Activities: The decrease in cash provided by financing activities for the quarter and year to date was due to higher net repayments under committed credit facilities classified as long-term and changes in short-term borrowings, partially offset by: (i) higher proceeds from the issuance of common shares; (ii) lower repayments of long-term debt; (iii) higher advances from non-controlling interests; and (iv) higher proceeds from long-term debt. Proceeds from the issuance of preferences shares were also lower year to date compared to the same period in 2010.

Net proceeds from short-term borrowings were $85 million for the quarter compared to $122 million for the same quarter last year. Net repayments of short-term borrowings were $115 million year to date compared to $4 million for the same period last year. The changes in short-term borrowings were driven by the FortisBC Energy companies, due to seasonality differences and timing of repayments using proceeds from equity injections from the Corporation, and Caribbean Utilities.

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

Proceeds from Long-Term Debt, Net of Issue Costs (Unaudited)						
Periods Ended September 30		**Quarter**			**Year-to-Date**	
($ millions)	**2011**	2010	Variance	**2011**	2010	Variance
Caribbean Utilities [(1)]	**9**	-	9	**38**	-	38
Other	**-**	-	-	**1**	-	1
Total	**9**	-	9	**39**	-	39

[(1)] Issued 15-year US$15 million 4.85% and 20-year US$25 million 5.10% unsecured notes. The first tranche of US$30 million was issued in June 2011 and the second tranche of US$10 million was issued in July 2011. The net proceeds were used to repay current installments on long-term debt and short-term borrowings and to finance capital expenditures.

Repayments of Long-Term Debt and Capital Lease Obligations (Unaudited)						
Periods Ended September 30		**Quarter**			**Year-to-Date**	
($ millions)	**2011**	2010	Variance	**2011**	2010	Variance
FortisBC Energy Companies	**-**	-	-	**-**	(1)	1
FortisBC Electric	**-**	-	-	**-**	(1)	1
Maritime Electric	**-**	-	-	**-**	(15)	15
Caribbean Utilities	**-**	-	-	**(12)**	(15)	3
Fortis Properties	**(2)**	(1)	(1)	**(6)**	(53)	47
Corporate [(1)]	**-**	-	-	**-**	(125)	125
Other	**-**	(2)	2	**(6)**	(5)	(1)
Total	**(2)**	(3)	1	**(24)**	(215)	191

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

Net Borrowings (Repayments) Under Committed Credit Facilities (Unaudited)						
Periods Ended September 30		**Quarter**			**Year-to-Date**	
($ millions)	**2011**	2010	Variance	**2011**	2010	Variance
FortisAlberta	**33**	22	11	**50**	82	(32)
FortisBC Electric	**(7)**	15	(22)	**-**	27	(27)
Newfoundland Power	**(13)**	(18)	5	**10**	(5)	15
Corporate	**(191)**	17	(208)	**(165)**	89	(254)
Total	**(178)**	36	(214)	**(105)**	193	(298)

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

Advances of approximately $20 million for the quarter and $76 million year to date were received from non-controlling interests in the Waneta Partnership to finance capital spending related to the Waneta Expansion Project.

In June 2011 Fortis publicly issued 9.1 million common shares for gross proceeds of approximately $300 million. In July 2011 an additional 1.24 million common shares of Fortis were publicly issued upon the exercise of an over-allotment option, resulting in gross proceeds of approximately $41 million. The total net proceeds from the common share offering of $327 million were used to repay borrowings under credit facilities and finance equity injections into the regulated utilities in western Canada and the non-regulated Waneta Expansion Project, in support of infrastructure investment, and for general corporate purposes.

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

Common share dividends paid during the third quarter of 2011 were $38 million, net of $16 million in dividends reinvested, compared to $33 million, net of $15 million in dividends reinvested, paid during the same quarter of 2010. Common share dividends paid year-to-date 2011 were $109 million, net of $47 million in dividends reinvested, compared to $102 million, net of $43 million in dividends reinvested, paid year-to-date 2010. The dividend paid per common share for each of the first three quarters of 2011 was $0.29 compared to $0.28 for each of the first three quarters of 2010. The weighted average number of common shares outstanding for the third quarter and year to date were 186.5 million and 179.5 million, respectively, compared to 173.2 million and 172.4 million, for the third quarter and year to date, respectively, in 2010.

CONTRACTUAL OBLIGATIONS

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

Contractual Obligations (Unaudited) **As at September 30, 2011** *($ millions)*	**Total**	Due within 1 year	Due in years 2 and 3	Due in years 4 and 5	Due after 5 years
Long-term debt	**5,595**	88	439	817	4,251
Waneta Partnership promissory note	**72**	-	-	-	72
Brilliant Terminal Station	**59**	3	5	5	46
Gas purchase contract obligations (1)	**433**	258	170	5	-
Power purchase obligations (2)					
FortisBC Electric	**2,877**	44	87	83	2,663
FortisOntario	**420**	42	98	103	177
Maritime Electric	**203**	55	77	57	14
Capital cost (3)	**465**	18	35	36	376
Joint-use asset and share service agreements	**64**	4	8	7	45
Office lease – FortisBC Electric	**18**	2	4	3	9
Operating lease obligations	**148**	20	33	31	64
Defined benefit pension funding contributions (4)	**66**	30	32	1	3
Other	**21**	4	7	6	4
Total	**10,441**	568	995	1,154	7,724

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

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

(3) Maritime Electric has entitlement to approximately 4.7% of the output from Point Lepreau for the life of the unit. As part of its participation agreement, the Company is obligated to pay its share of capital and operating costs of the unit, which have been included in the table above. However, as a result of the Accord, the Government of PEI is assuming responsibility for the payment of the monthly operating and maintenance costs related to Point Lepreau, effective March 1, 2011 until Point Lepreau is fully refurbished, which is expected by fall 2012.

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

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

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

Other contractual obligations, which are not reflected in the above table, did not materially change from those disclosed in the MD&A for the year ended December 31, 2010.

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

CAPITAL STRUCTURE

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

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

Capital Structure (Unaudited)	**As at**			
	September 30, 2011		December 31, 2010	
	($ millions)	***(%)***	*($ millions)*	*(%)*
Total debt and capital lease obligations (net of cash) (1)	**5,729**	**54.8**	5,914	58.4
Preference shares (2)	**912**	**8.7**	912	9.0
Common shareholders' equity	**3,809**	**36.5**	3,305	32.6
Total (3)	**10,450**	**100.0**	10,131	100.0

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

The change in the capital structure was driven by the public issuance of approximately $341 million in common shares in June and July 2011, combined with common shares issued under the Corporation's dividend reinvestment and stock option plans and the reclassification of unrealized foreign currency translation losses related to the Corporation's previous investment in Belize Electricity to long-term other assets. Also contributing to the change in the capital structure was net earnings applicable to common shares, net of dividends, and lower borrowings under credit facilities.

CREDIT RATINGS

The Corporation's credit ratings are as follows:

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

During the third quarter of 2011, DBRS confirmed the Corporation's existing debt credit rating at A(low). The credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level, the Corporation's reasonable credit metrics and its demonstrated ability and continued focus on acquiring and integrating stable regulated utility businesses financed on a conservative basis.

CAPITAL PROGRAM

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

A breakdown of the $806 million in gross capital expenditures by segment year-to-date 2011 is provided in the following table.

Gross Consolidated Capital Expenditures (Unaudited) *(1)*
Year-to-Date September 30, 2011
($ millions)

FortisBC Energy Companies	Fortis Alberta (2)	FortisBC Electric	Newfoundland Power	Other Regulated Electric Utilities - Canadian	**Total Regulated Utilities - Canadian**	**Regulated Electric Utilities - Caribbean (3)**	**Non-Regulated - Utility (4)**	**Fortis Properties**	**Total**
179	253	78	55	33	**598**	**57**	**131**	**20**	**806**

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

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

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

In August 2011 Fortis Properties received municipal government approval to construct a $50 million 12-storey office building in downtown St. John's, Newfoundland. The building will feature 152,000 square feet of Class A office space and include 262 parking spaces. Construction is expected to be completed in the second half of 2013.

Approximately $33 million of the capital cost of FEI's Customer Care Enhancement Project is expected to be incurred in the first half of 2012, up from the original estimate of $10 million expected to be incurred in 2012 as disclosed as at December 31, 2010. The estimated total project cost remains unchanged at $116 million and the in-house customer care function is expected to come on-line starting January 2012.

During 2011 FortisAlberta continued with the replacement of vintage poles under its pole management program, which involves 96,000 poles in total, to prevent risk of failure due to age. The total capital cost of the program through to 2019 is now expected to be approximately $335 million, an increase from the $283 million forecast as at December 31, 2010. The increase is primarily due to a revised forecast estimating higher labour and material costs later in the project.

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

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

During the third quarter of 2011, the second new 9-MW diesel-powered generating unit at Fortis Turks and Caicos came into service. The third unit is expected to be delivered in 2014 with the total cost of the three units estimated at approximately $29 million.

During the fall of 2011, FortisBC Electric substantially completed its $105 million Okanagan Transmission Replacement Project.

Construction progress on the $900 million Waneta Expansion Project is going well and the project is currently on schedule. Major construction activities on-site include excavation of the intake, powerhouse and power tunnels.

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

CASH FLOW REQUIREMENTS

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

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

As at September 30, 2011, management expects consolidated long-term debt maturities and repayments to average approximately $270 million annually over the next five years. The combination of available credit facilities and relatively low annual debt maturities and repayments provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

As the hydroelectric assets and water rights of the Exploits River Hydro Partnership ("Exploits Partnership") had been provided as security for the Exploits Partnership term loan, the expropriation of such assets and rights by the Government of Newfoundland and Labrador constituted an event of default under the loan. The term loan is without recourse to Fortis and was approximately $56 million as at September 30, 2011 (December 31, 2010 - $58 million). The lenders of the term loan have not demanded accelerated repayment. The scheduled repayments under the term loan are being made by Nalcor, a Crown corporation, acting as an agent for the Government of Newfoundland and Labrador with respect to the expropriation matters. For further information refer to Note 30 to the Corporation's 2010 annual audited consolidated financial statements.

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

CREDIT FACILITIES

As at September 30, 2011, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.3 billion, of which $1.9 billion was unused, including the Corporation's unused $800 million committed revolving credit facility. The credit facilities are syndicated mostly with the seven largest Canadian banks, with no one bank holding more than 20% of these facilities. Approximately $2.2 billion of the total credit facilities are committed facilities with maturities between 2012 and 2015.

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

Credit Facilities (Unaudited)				**As at**	
($ millions)	Corporate and Other	Regulated Utilities	Fortis Properties	**September 30, 2011**	December 31, 2010
Total credit facilities	845	1,490	13	**2,348**	2,109
Credit facilities utilized:					
Short-term borrowings	-	(239)	(3)	**(242)**	(358)
Long-term debt (including current portion)	-	(114)	-	**(114)**	(218)
Letters of credit outstanding	(1)	(65)	-	**(66)**	(124)
Credit facilities unused	844	1,072	10	**1,926**	1,409

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

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

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

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

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

In August 2011 the Corporation renegotiated and amended its unsecured committed revolving credit facility, increasing the amount available under the facility to $800 million from $600 million and extending the maturity date of the facility to July 2015 from May 2012. At any time prior to maturity, the Corporation may provide written notice to increase the amount available under the facility to $1 billion. The amended credit facility agreement reflects an increase in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

In September 2011 FortisAlberta amended its unsecured committed revolving credit facility to increase the amount available under the facility to $250 million from $200 million and extend the maturity date to September 2015 from May 2012. The amended credit facility agreement reflects an increase in pricing.

FINANCIAL INSTRUMENTS

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

Financial Instruments (Unaudited)	**As at**			
	September 30, 2011		December 31, 2010	
	Carrying	**Estimated**	Carrying	Estimated
($ millions)	**Value**	**Fair Value**	Value	Fair Value
Waneta Partnership promissory note	**44**	**47**	42	40
Long-term debt, including current portion [(1)]	**5,595**	**6,728**	5,669	6,431
Preference shares, classified as debt [(2)]	**320**	**345**	320	344

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

[(2)] Preference shares classified as equity do not meet the definition of a financial instrument; however, the estimated fair value of the Corporation's $592 million preference shares classified as equity was $616 million as at September 30, 2011 (December 31, 2010 – $615 million).

Excluded from the above table is the $120 million long-term other asset as at September 30, 2011 related to the Corporation's previous investment in Belize Electricity. The fair value of this financial asset is not determinable at this time.

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

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

As at September 30, 2011, US$550 million of the US$590 million corporately issued long-term debt (December 31, 2010 – US$590 million of US$590 million) had been designated as an effective hedge of the Corporation's net investments in self-sustaining foreign subsidiaries. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar borrowings designated as effective hedges are recognized in other comprehensive income and help offset unrealized foreign currency gains and losses on the net investments in self-sustaining foreign subsidiaries, which are also recognized in other comprehensive income.

Effective June 20, 2011, the Corporation's asset associated with its previous investment in Belize Electricity, recorded in long-term other assets, does not qualify for hedge accounting as Belize Electricity is no longer a self-sustaining foreign subsidiary of Fortis. As a result, as at September 30, 2011, approximately US$40 million of corporately issued debt that previously hedged the former investment in Belize Electricity is not an effective hedge. Effective June 20, 2011, foreign exchange gains and losses on the translation of the asset associated with Belize Electricity and the corporately issued US dollar-denominated debt that previously qualified as a hedge of the investment are required to be recognized in earnings. As a result, the Corporation recognized a net after-tax foreign exchange gain of approximately $2.5 million in earnings during the quarter ended September 30, 2011. As at September 30, 2011, all of the Corporation's net investments in self-sustaining foreign subsidiaries were hedged (December 31, 2010 - 99%).

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

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

Derivative Financial Instruments (Unaudited)					**As at**	
	September 30, 2011				December 31, 2010	
Liability	**Term to Maturity *(years)***	**Number of Contracts**	**Carrying Value *($ millions)***	**Estimated Fair Value *($ millions)***	Carrying Value *($ millions)*	Estimated Fair Value *($ millions)*
Foreign exchange forward contract	**< 1**	**1**	**-**	**-**	-	-
Fuel option contracts	**< 1**	**2**	**(1)**	**(1)**	-	-
Natural gas derivatives:						
Swaps and options	**Up to 3**	**201**	**(101)**	**(101)**	(162)	(162)
Gas purchase contract premiums	**Up to 2**	**85**	**(3)**	**(3)**	(5)	(5)

The foreign exchange forward contract is held by FEI. During 2010 FEI entered into a foreign exchange forward contract to hedge the cash flow risk related to approximately US$5 million remaining to be paid under a contract for the implementation of a customer information system. FEVI was also party to a foreign exchange forward contract to hedge the cash flow risk related to US dollar payments under a contract for the construction of the LNG storage facility on Vancouver Island. During the third quarter of 2011, FEVI's foreign exchange forward contract matured.

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

The natural gas derivatives are held by the FortisBC Energy companies and are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The price risk-management strategy of the FortisBC Energy companies aims to improve the likelihood that natural gas prices remain competitive, to temper gas price volatility on customer rates and to reduce the risk of regional price discrepancies. For further information, refer to the "Material Regulatory Decisions and Applications - FEI" section of this MD&A.

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

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

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

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $66 million, as at September 30, 2011, the Corporation had no off-balance sheet arrangements, such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities, that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

BUSINESS RISK MANAGEMENT

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

Investment in Belize: In June 2011 the GOB expropriated the Corporation's investment in Belize Electricity. Fortis has commissioned an independent valuation of its previous investment in Belize Electricity and expects to submit its claim to the GOB for compensation during the fourth quarter of 2011. The Corporation is exposed to risk associated with the amount of compensation to be paid for its previous investment in Belize Electricity, the timeliness of payment of the compensation and the ability of the GOB to pay the compensation owing to Fortis. The book value of the Corporation's previous investment in Belize Electricity recorded in long-term other assets on the consolidated balance sheet of Fortis was $120 million as at September 30, 2011.

The Prime Minister of Belize has stated that it is not the GOB's intention to expropriate BECOL. As at September 30, 2011, the book value of the Corporation's investment in BECOL was $159 million.

For further information, refer to the "Corporate Overview" section of this MD&A.

Economic Conditions: The Corporation's service territory in the Caribbean region continues to be impacted by challenging economic conditions. The population on Grand Cayman and the Turks and Caicos Islands has been declining as many non-locals working in the construction industry have returned to their home countries or other jurisdictions, as a result of the strong retraction in construction activity due to the weak local economies.

On the positive side, the recent completion and commissioning of phase one of a local airport expansion at the principal airport in Providenciales in the Turks and Caicos Islands in September 2011 should help foster future economic growth, mainly in the tourism and commercial sectors, allowing direct flights from Europe and accommodating more flights from North America. On Grand Cayman, several residential, resort and commercial projects are being completed in 2011, which have the potential to increase load and electricity sales for Caribbean Utilities.

Any sustained recovery of the economy in the Caribbean region, however, will hinge on the recovery of the U.S. economy. In line with the general U.S. economic forecast, it is expected that the current local economic weakness in the Caribbean region will continue into 2012 and possibly 2013, resulting in little-to-no growth in electricity sales for Caribbean Utilities and Fortis Turks and Caicos during those years.

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

Capital Resources and Liquidity Risk - Credit Ratings: Fortis and its regulated utilities do not anticipate any material adverse rating actions by the credit rating agencies in the near term. Year-to-date 2011, DBRS confirmed its existing credit ratings for Newfoundland Power, Caribbean Utilities, FortisBC Electric, Fortis, FHI and FEI. Also, Moody's Investors Service confirmed its existing credit ratings for Newfoundland Power and FEI, while S&P downgraded Caribbean Utilities credit rating from A to A- due to a weak customer market and increased business risks, but maintained its existing credit rating for Maritime Electric.

Defined Benefit Pension Plan Assets: As at September 30, 2011, the fair value of the Corporation's consolidated defined benefit pension plan assets was $751 million, up $24 million or 3%, from $727 million as at December 31, 2010.

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

The two collective agreements between Newfoundland Power and the International Brotherhood of Electrical Workers labour union expired on September 30, 2011. Negotiations to renew the collective agreements began in October 2011.

CHANGE IN ACCOUNTING TREATMENT

Effective January 1, 2011, as approved by the regulator, the cost of OPEB plans at Newfoundland Power is being expensed and recovered in customer rates based on the accrual method of accounting for OPEB plans. Additionally, the Company's transitional regulatory OPEB asset of $53 million as at December 31, 2010 is being amortized on a straight-line basis over 15 years. During the three and nine months ended September 30, 2011, operating expenses increased by approximately $2 million and $6 million, respectively, as a result of this change in accounting treatment. Prior to January 1, 2011, the cost of OPEB plans at Newfoundland Power was being expensed and recovered in customer rates based on the cash payments made.

FUTURE ACCOUNTING CHANGES

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

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

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

During the fourth quarter of 2010, the Corporation developed a three-phase plan to adopt US GAAP effective January 1, 2012. The following is an overview of the activities under each phase and their current status.

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

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

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

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

Phase III - Implementation and Review: Phase III is currently ongoing and has involved the implementation of financial reporting systems and internal control changes required by the Corporation to prepare and file its consolidated financial statements in accordance with US GAAP beginning in 2012, and the communication of associated impacts.

The Corporation will prepare and file its audited Canadian GAAP consolidated financial statements for the year ending December 31, 2011 in the usual manner. The Corporation then intends to voluntarily prepare and file audited US GAAP consolidated financial statements for the year ending December 31, 2011, with 2010 comparatives. The Corporation's voluntary filing of audited US GAAP consolidated financial statements for the year ending December 31, 2011, subsequent to the filing of its audited Canadian GAAP consolidated financial statements for the year ending December 31, 2011, has been approved by the OSC and is expected to be completed by March 31, 2012. Beginning with the first quarter of 2012, the Corporation's unaudited interim consolidated financial statements will be prepared and filed in accordance with US GAAP.

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

Financial Statement Impacts - US GAAP: The areas identified to date where differences between US GAAP and Canadian GAAP are expected to have the most significant financial statement impacts are outlined below. The identified impacts are unaudited and are subject to change based on further analysis.

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

US GAAP requires recognition of the funded or unfunded status of defined benefit plans on the balance sheet. Unamortized balances related to past service costs, actuarial gains and losses and transitional obligations are separately recognized on the balance sheet as a component of accumulated other comprehensive income or, in the case of entities with activities subject to rate regulation, as regulatory assets or liabilities for recovery from, or refund to, customers in future rates. Subsequent changes to past service costs, actuarial gains and losses and transitional obligations would be recognized as part of pension expense, where required by the regulator, or otherwise as a change in the regulatory asset or liability. Therefore, upon adoption of US GAAP, the Corporation's rate-regulated subsidiaries will recognize the funded or unfunded status of their defined benefit pension plans on the balance sheet with the above noted unamortized balances recognized as regulatory assets or liabilities.

US GAAP also requires that OPEB costs be recorded on an accrual basis, and prohibits the recognition of regulatory assets or liabilities associated with OPEB costs that are recovered on a cash basis. FortisAlberta has historically recovered its OPEB costs on a cash basis, as opposed to an accrual basis, and will likely continue to do so as ordered by its regulator. Therefore, FortisAlberta's regulatory asset associated with OPEB costs does not meet the criteria for recognition under US GAAP. Historically, Newfoundland Power had also recovered its OPEB costs on a cash basis. However, in December 2010, the regulator approved Newfoundland Power's application to: (i) adopt the accrual method of accounting for OPEB costs, effective January 1, 2011; (ii) recover the transitional regulatory asset associated with the adoption of accrual accounting over a 15-year period; and (iii) adopt an OPEB cost-variance deferral account to capture differences between OPEB expense calculated in accordance with GAAP and OPEB expense approved by the regulator for rate-setting purposes. The rules under

US GAAP related to accounting for OPEBs by rate-regulated entities require that Newfoundland Power de-recognize its OPEB regulatory asset as of January 1, 2010 on the premise that, as of that date, Newfoundland Power was recovering its OPEB costs on a cash basis. However, the regulatory asset will be re-recognized through earnings in accordance with US GAAP in 2010 based on the regulator's approval of Newfoundland Power's application to adopt the accrual method of accounting for OPEBs effective January 1, 2011 and to recover the associated transitional regulatory asset over a 15-year period.

Additional differences between Canadian GAAP and US GAAP in terms of accounting for defined benefit plans include the determination of the measurement date and the attribution period over which pension expense is recognized. Canadian GAAP allows for the use of a measurement date up to three months prior to the date of an entity's fiscal year end. However, US GAAP requires the entity's fiscal year end to be used as the measurement date. Canadian GAAP also allows for the use of an attribution period for defined benefit pension plans, under specific circumstances, that extends beyond the date when the credited service period ends. However, US GAAP allows for the use of an attribution period for defined benefit pension plans up to the date when credited service ends. The differences are expected to impact the calculation of the Corporation's consolidated benefit obligation, which will be mostly offset by a corresponding change to regulatory assets or liabilities.

With the exception of a one-time adjustment with respect to Newfoundland Power's inability to recognize its OPEB regulatory asset as of January 1, 2010 and its ability to subsequently re-recognize this OPEB regulatory asset through earnings in 2010, the impact of adopting US GAAP with respect to accounting for employee future benefits, i.e., pensions and OPEBs, is not currently expected to have a material impact on the Corporation's consolidated earnings.

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

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

The anticipated effect of retrospectively recognizing Brilliant as a capital lease upon adoption of US GAAP includes the recognition on the consolidated balance sheet of a utility capital asset with an offsetting capital lease obligation for an equivalent amount. Each subsequent reporting period, the total amount of amortization and interest expense to be recognized under capital lease accounting is expected to differ from the amount paid under the BPPA and recovered through current electricity rates as permitted by the BCUC. This timing difference is expected to be recognized as a regulatory asset, with amounts recovered through electricity rates expected to equal the combined amount of the capitalized lease asset and interest on the lease obligation over the term of the BPPA.

Since US GAAP allows for entities to account for the effects of rate regulation, the impact of adopting capital lease accounting for Brilliant is not expected to affect the Corporation's consolidated earnings.

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

Corporate income taxes: Under Canadian GAAP, the Corporation has calculated and recognized corporate income taxes using substantively enacted corporate income tax rates. Under US GAAP, the Corporation is required to calculate and record corporate income taxes based on enacted corporate income tax rates. Therefore, upon adoption of US GAAP, the Corporation will be required to recognize the impact of the difference between enacted tax rates and substantively enacted tax rates related to the calculation of Part VI.1 tax deductions associated with preference share dividends. The retroactive adjustment to recognize the Part VI.1 tax deductions based on enacted corporate income tax rates will result in a reduction in opening retained earnings under US GAAP and annual earnings thereafter. However, the adjustments are expected to reverse once pending Canadian federal legislation is passed and proposed corporate income tax rate changes become enacted.

The above items do not represent a complete list of expected differences between US GAAP and Canadian GAAP, and are subject to change. Other less significant differences have also been identified. Analysis also remains ongoing and additional areas where the Corporation's consolidated financial statements could be materially impacted may be identified prior to the Corporation's voluntary preparation and filing of its audited US GAAP consolidated financial statements for the year ending December 31, 2011. A detailed reconciliation between the Corporation's audited Canadian GAAP and US GAAP financial statements for 2011, including 2010 comparatives, will be disclosed as part of that voluntary filing.

The unaudited, estimated quantification and reconciliation of the Corporation's consolidated balance sheet as of December 31, 2010 prepared in accordance with US GAAP versus Canadian GAAP, based on the differences identified to date, may be summarized as follows.

Total assets as of December 31, 2010 are estimated to increase by approximately $530 million. The estimated increase is due primarily to expected increases in regulatory assets and utility capital assets in accordance with US GAAP.

Total liabilities as of December 31, 2010 are estimated to increase by approximately $260 million. The estimated increase is due primarily to the expected increases in long-term debt and capital lease obligations and pension liabilities in accordance with US GAAP, partially offset by the reclassification of preference shares from liabilities to shareholders' equity.

Shareholders' equity as of December 31, 2010 is estimated to increase by approximately $270 million. The estimated increase is due primarily to the expected reclassification of preference shares from liabilities to shareholders' equity in accordance with US GAAP, partially offset by an estimated reduction in retained earnings of approximately $35 million based on the retrospective application of US GAAP. Approximately half of the reduction in retained earnings results from higher corporate income taxes, as referred to above, and is expected to reverse in a future period once pending Canadian federal income tax legislation is passed and proposed Part VI.1 tax rate changes become enacted.

As previously indicated, and subject to the above referenced one-time adjustment with respect to Newfoundland Power's inability to recognize its OPEB regulatory asset as of January 1, 2010 and its subsequent ability to re-recognize this OPEB regulatory asset as of December 31, 2010, no material adjustments to the Corporation's consolidated earnings are currently expected under US GAAP due to the Corporation's continued ability to apply rate-regulated accounting policies.

The unaudited, estimated quantification and reconciliation of the Corporation's consolidated statement of earnings for the year ended December 31, 2010 prepared in accordance with US GAAP versus Canadian GAAP, based on the differences identified to date, may be summarized as follows.

Consolidated net earnings to be reported in accordance with US GAAP for the year ended December 31, 2010, prior to the one-time adjustment to re-recognize Newfoundland Power's OPEB regulatory asset, are estimated to increase by approximately $8 million (from $323 million to $331 million). The estimated increase is due primarily to the expected reclassification of preference share dividends in accordance with US GAAP from finance charges to earnings attributable to preference equity shareholders, partially offset by increases in other finance charges and corporate income taxes, as referred to above, which are expected to reduce earnings attributable to common equity shareholders by approximately $9 million.

The one-time, non-recurring adjustment to re-recognize Newfoundland Power's OPEB regulatory asset as at December 31, 2010 is estimated to increase consolidated net earnings for the year ended December 31, 2010 by approximately $46 million. This adjustment is not expected to impact accumulated retained earnings as at December 31, 2010, as compared to retained earnings reported in accordance with Canadian GAAP as at December 31, 2010, as it reverses an adjustment made to derecognize the OPEB regulatory asset upon adoption of US GAAP as at January 1, 2010.

The quantification and reconciliation of the Corporation's consolidated financial statements from Canadian GAAP to US GAAP for the 2011 annual reporting period is expected to be completed by March 31, 2012.

CRITICAL ACCOUNTING ESTIMATES

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

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

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

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended December 31, 2009 through September 30, 2011. The quarterly information has been obtained from the Corporation's interim unaudited consolidated financial statements which, in the opinion of management, have been prepared in accordance with Canadian GAAP and as required by utility regulators. The timing of the recognition of certain assets, liabilities, revenue and expenses, as a result of regulation, may differ from that otherwise expected using Canadian GAAP for non-regulated entities. The differences and nature of regulation are disclosed in Notes 2, 3 and 5 to the Corporation's 2010 annual audited consolidated financial statements. The quarterly financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results (Unaudited) Quarter Ended	Revenue *($ millions)*	Net Earnings Attributable to Common Equity Shareholders *($ millions)*	Earnings per Common Share Basic *($)*	 Diluted *($)*
September 30, 2011	721	58	0.31	0.31
June 30, 2011	850	58	0.33	0.33
March 31, 2011	1,164	117	0.67	0.65
December 31, 2010	1,036	85	0.49	0.47
September 30, 2010	720	45	0.26	0.26
June 30, 2010	835	55	0.32	0.32
March 31, 2010	1,073	100	0.58	0.56
December 31, 2009	1,020	81	0.48	0.46

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

September 2011/September 2010: Net earnings attributable to common equity shareholders were $58 million, or $0.31 per common share, for the third quarter of 2011 compared to earnings of $45 million, or $0.26 per common share, for the third quarter of 2010. A discussion of the variances between the financial results for the third quarter of 2011 and the third quarter of 2010 is provided in the "Financial Highlights" section of this MD&A.

June 2011/June 2010: Net earnings attributable to common equity shareholders were $58 million, or $0.33 per common share, for the second quarter of 2011 compared to earnings of $55 million, or $0.32 per common share, for the second quarter of 2010. The increase was mainly due to improved performance at the Canadian Regulated Electric Utilities, driven by rate base growth associated with utility infrastructure investment at the electric utilities in western Canada, additional return earned on FortisAlberta's investment in automated meters, lower market-priced purchased power costs at FortisBC Electric and a higher allowed ROE at Algoma Power. Results also improved due to lower corporate business development costs. The above increase in earnings was partially offset by the unfavourable impact of the timing of spending of certain regulator-approved increased operating expenses at the FortisBC Energy companies during 2011, lower non-regulated hydroelectric generation in Belize, and lower contribution from Fortis Properties reflecting lower occupancies at hotel operations in western Canada and increased operating expenses. During the second quarter of 2011, the GOB expropriated the Corporation's investment in Belize Electricity.

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

December 2010/December 2009: Net earnings attributable to common equity shareholders were $85 million, or $0.49 per common share, for the fourth quarter of 2010 compared to earnings of $81 million, or $0.48 per common share, for the fourth quarter of 2009. The increase was mainly due to improved performance at Canadian Regulated Electric Utilities, non-regulated hydroelectric generation operations in Belize and lower effective corporate income taxes at Fortis Properties, partially offset by lower earnings from the FortisBC Energy companies and Caribbean Regulated Electric Utilities. Improved performance at Canadian Regulated Electric Utilities was driven by rate base growth associated with utility infrastructure investment, combined with customer growth at FortisAlberta and the higher allowed ROE at FortisBC Electric. Earnings were lower quarter over quarter at the FortisBC Energy companies, as a result of higher regulator-approved operating expenses and the timing of the recognition of these increased expenses, and at Caribbean Regulated Electric Utilities, mainly due to lower electricity sales associated with cooler-than-normal temperatures experienced in the region and the inability of Belize Electricity to earn a fair and reasonable return due to regulatory challenges. Earnings for the fourth quarter of 2009 were reduced by $5 million related to the expensing of the project cost overrun associated with the conversion of Whistler customer appliances from propane to natural gas, but were favourably impacted by a one-time $3 million tax adjustment at FortisOntario.

SUBSEQUENT EVENTS

On October 5, 2011, Newfoundland Power received proceeds of approximately $46 million from Bell Aliant upon the closing of the sale of 40% of Newfoundland Power's joint-use poles.

On October 18, 2011, Fortis Properties acquired the 160-room, full-service Hilton Suites Winnipeg Airport hotel for an aggregate cash purchase price of approximately $25 million.

On October 19, 2011, FortisAlberta issued 30-year $125 million 4.54% unsecured debentures. The proceeds of the debt offering were mainly used to repay borrowings under the Company's credit facility incurred to finance capital expenditures, and for general corporate purposes.

OUTLOOK

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

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

OUTSTANDING SHARE DATA

As at November 2, 2011, the Corporation had issued and outstanding approximately 187 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 2, 2011 is as follows:

Conversion of Securities into Common Shares (Unaudited) As at November 2, 2011 **Security**	**Number of Common Shares** *(millions)*
Stock Options	**4.8**
Convertible Debt	**1.4**
First Preference Shares, Series C	**3.9**
First Preference Shares, Series E	**6.2**
Total	**16.3**

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

FORTIS INC.

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

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

	September 30, 2011	December 31, 2010 (Note 23)
ASSETS		
Current assets		
Cash and cash equivalents	$ 108	$ 109
Assets held for sale (Note 5)	45	-
Accounts receivable (Note 20)	469	655
Prepaid expenses	33	17
Regulatory assets (Note 6)	196	241
Inventories (Note 7)	194	168
Future income taxes	18	14
	1,063	1,204
Assets held for sale (Note 5)	-	45
Other assets (Note 8)	284	168
Regulatory assets (Note 6)	945	848
Future income taxes	18	16
Utility capital assets	8,490	8,185
Income producing properties	563	560
Intangible assets	332	324
Goodwill	1,560	1,553
	$ 13,255	$ 12,903
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings (Note 20)	$ 242	$ 358
Accounts payable and accrued charges	853	953
Dividends payable	58	54
Income taxes payable	31	30
Regulatory liabilities (Note 6)	50	60
Current installments of long-term debt and capital lease obligations (Note 9)	91	56
Future income taxes	4	6
	1,329	1,517
Other liabilities	318	308
Regulatory liabilities (Note 6)	512	467
Future income taxes	666	623
Long-term debt and capital lease obligations (Note 9)	5,504	5,609
Preference shares	320	320
	8,649	8,844
Shareholders' equity		
Common shares (Note 10)	2,973	2,578
Preference shares	592	592
Contributed surplus	13	12
Equity portion of convertible debentures	5	5
Accumulated other comprehensive loss (Note 12)	(60)	(94)
Retained earnings	878	804
	4,401	3,897
Non-controlling interests	205	162
	4,606	4,059
	$ 13,255	$ 12,903

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

Fortis Inc.

Consolidated Statements of Earnings (Unaudited)

For the periods ended September 30

(in millions of Canadian dollars, except per share amounts)

	Quarter Ended		Nine Months Ended	
	2011	2010	**2011**	2010
Revenue	**$ 721**	$ 720	**$ 2,735**	$ 2,627
Expenses				
Energy supply costs	**246**	259	**1,207**	1,178
Operating	**202**	196	**627**	600
Amortization	**105**	117	**311**	307
	553	572	**2,145**	2,085
Operating income	**168**	148	**590**	542
Finance charges (Note 14)	**88**	88	**271**	266
Earnings before corporate taxes	**80**	60	**319**	276
Corporate taxes (Note 15)	**12**	5	**57**	48
Net earnings	**$ 68**	$ 55	**$ 262**	$ 228
Net earnings attributable to:				
Non-controlling interests	**$ 3**	$ 3	**$ 7**	$ 7
Preference equity shareholders	**7**	7	**22**	21
Common equity shareholders	**58**	45	**233**	200
	$ 68	$ 55	**$ 262**	$ 228
Earnings per common share (Note 10)				
Basic	**$ 0.31**	$ 0.26	**$ 1.30**	$ 1.16
Diluted	**$ 0.31**	$ 0.26	**$ 1.29**	$ 1.15

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	
	2011	2010	**2011**	2010
Balance at beginning of period	**$ 874**	$ 773	**$ 804**	$ 763
Net earnings attributable to common and preference equity shareholders	**65**	52	**255**	221
	939	825	**1,059**	984
Dividends on common shares	**(54)**	(48)	**(159)**	(193)
Dividends on preference shares classified as equity	**(7)**	(7)	**(22)**	(21)
Balance at end of period	**$ 878**	$ 770	**$ 878**	$ 770

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	
	2011	2010	**2011**	2010
Net earnings	**$ 68**	$ 55	**$ 262**	$ 228
Other comprehensive income (loss)				
Unrealized foreign currency translation gains (losses) on net investments in self-sustaining foreign operations	**46**	(21)	**28**	(13)
(Losses) gains on hedges of net investments in self-sustaining foreign operations	**(45)**	13	**(27)**	8
Corporate tax recovery (expense)	**7**	(2)	**4**	(1)
Unrealized foreign currency translation gains (losses), net of hedging activities and tax (Note 12)	**8**	(10)	**5**	(6)
Reclassification to earnings of net losses on derivative instruments previously discontinued as cash flow hedges, net of tax (Note 12)	**1**	1	**1**	1
Comprehensive income	**$ 77**	$ 46	**$ 268**	$ 223
Comprehensive income attributable to:				
Non-controlling interests	**$ 3**	$ 3	**$ 7**	$ 7
Preference equity shareholders	**7**	7	**22**	21
Common equity shareholders	**67**	36	**239**	195
	$ 77	$ 46	**$ 268**	$ 223

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	
	2011	2010	**2011**	2010
		(Note 23)		(Note 23)
Operating activities				
Net earnings	**$ 68**	$ 55	**$ 262**	$ 228
Items not affecting cash:				
Amortization - utility capital assets and income producing properties	**94**	107	**282**	276
Amortization - intangible assets	**11**	10	**31**	30
Amortization - other	**-**	-	**(2)**	1
Future income taxes	**4**	-	**3**	(1)
Other	**4**	(3)	**9**	(1)
Change in long-term regulatory assets and liabilities	**(27)**	(4)	**(9)**	(4)
	154	165	**576**	529
Change in non-cash operating working capital	**(3)**	(36)	**102**	5
	151	129	**678**	534
Investing activities				
Change in other assets and other liabilities	**-**	(2)	**(5)**	1
Capital expenditures - utility capital assets	**(260)**	(256)	**(747)**	(672)
Capital expenditures - income producing properties	**(11)**	(5)	**(20)**	(14)
Capital expenditures - intangible assets	**(16)**	(7)	**(39)**	(17)
Contributions in aid of construction	**18**	17	**49**	41
Proceeds on sale of utility capital assets and income producing properties	**-**	-	**6**	3
	(269)	(253)	**(756)**	(658)
Financing activities				
Change in short-term borrowings	**85**	122	**(115)**	(4)
Proceeds from long-term debt, net of issue costs	**9**	-	**39**	-
Repayments of long-term debt and capital lease obligations	**(2)**	(3)	**(24)**	(215)
Net (repayments) borrowings under committed credit facilities	**(178)**	36	**(105)**	193
Advances from non-controlling interests	**20**	-	**77**	1
Issue of common shares, net of costs and dividends reinvested	**40**	4	**341**	15
Issue of preference shares, net of costs	**-**	-	**-**	242
Dividends				
Common shares, net of dividends reinvested	**(38)**	(33)	**(109)**	(102)
Preference shares	**(7)**	(7)	**(22)**	(21)
Subsidiary dividends paid to non-controlling interests	**(2)**	(2)	**(6)**	(6)
	(73)	117	**76**	103
Effect of exchange rate changes on cash and cash equivalents	**1**	-	**1**	-
Change in cash and cash equivalents	**(190)**	(7)	**(1)**	(21)
Cash and cash equivalents, beginning of period	**298**	71	**109**	85
Cash and cash equivalents, end of period	**$ 108**	$ 64	**$ 108**	$ 64

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

1. DESCRIPTION OF THE BUSINESS

Nature of Operations

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

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

REGULATED UTILITIES

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

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

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

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

NON-REGULATED - FORTIS GENERATION

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

NON-REGULATED - FORTIS PROPERTIES

Fortis Properties owns and operates 22 hotels, including the Hilton Suites Winnipeg Airport hotel acquired in October 2011, collectively representing 4,300 rooms in eight Canadian provinces, and approximately 2.7 million square feet of commercial office and retail space primarily in Atlantic Canada (Note 22).

CORPORATE AND OTHER

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

All amounts are presented in Canadian dollars unless otherwise stated.

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

Effective January 1, 2011, as approved by the regulator, the cost of other post-employment benefit ("OPEB") plans at Newfoundland Power is being expensed and recovered in customer rates based on the accrual method of accounting for OPEB plans. Additionally, the Company's transitional regulatory OPEB asset of $53 million as at December 31, 2010 is being amortized on a straight-line basis over 15 years. During the three and nine months ended September 30, 2011, operating expenses increased by approximately $2 million and $6 million, respectively, as a result of this change in accounting treatment. Prior to January 1, 2011, the cost of OPEB plans at Newfoundland Power was being expensed and recovered in customer rates based on the cash payments made.

3. FUTURE ACCOUNTING CHANGES

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

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

3. FUTURE ACCOUNTING CHANGES (cont'd)

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

4. USE OF ESTIMATES

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

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

5. ASSETS HELD FOR SALE

On September 28, 2011, the Newfoundland and Labrador Board of Commissioners of Public Utilities issued an order that approved the sale of 40% of joint-use poles from Newfoundland Power to Bell Aliant Inc. ("Bell Aliant"). The Corporation has reclassified assets held for sale of approximately $45 million, representing the estimated sale price less costs to sell the joint-use poles, from long-term to current assets on the consolidated balance sheet as at September 30, 2011. The estimated sale price is subject to adjustment upon completion of a pole survey later in 2011 (Note 22).

6. REGULATORY ASSETS AND LIABILITIES

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

	As at	
($ millions)	**September 30, 2011**	December 31, 2010
Regulatory assets		(Note 23)
Future income taxes	**616**	568
Rate stabilization accounts - FortisBC Energy companies	**78**	146
Rate stabilization accounts - electric utilities	**57**	44
Regulatory OPEB plan assets	**63**	66
Alberta Electric System Operator ("AESO") charges deferral	**53**	19
Replacement energy deferral - Point Lepreau [(1)]	**47**	44
Deferred energy management costs	**30**	23
Deferred losses on disposal of utility capital assets	**21**	16
Deferred operating costs	**19**	11
Income taxes recoverable on OPEB plans	**18**	18
Capital cost recovery - Whistler pipeline	**16**	17
Deferred development costs for capital	**11**	11
2010 accrued distribution revenue adjustment rider	**9**	36
Deferred costs - smart meters	**9**	8
Deferred lease costs	**6**	6
Deferred pension costs	**4**	5
Other regulatory assets	**84**	51
Total regulatory assets	**1,141**	1,089
Less: current portion	**(196)**	(241)
Long-term regulatory assets	**945**	848

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

	As at	
($ millions)	**September 30, 2011**	December 31, 2010
Regulatory liabilities		
Asset removal and site restoration provision	**353**	339
Rate stabilization accounts - FortisBC Energy companies	**96**	60
Rate stabilization accounts - electric utilities	**33**	45
AESO charges deferral	**12**	9
Deferred interest	**10**	7
Performance-based rate-setting incentive liabilities	**9**	8
Southern Crossing Pipeline deferral	**8**	5
Unrecognized net gains on disposal of utility capital assets	**6**	8
2010 FEI revenue surplus	**2**	7
Unbilled revenue liability	**-**	5
Other regulatory liabilities	**33**	34
Total regulatory liabilities	**562**	527
Less: current portion	**(50)**	(60)
Long-term regulatory liabilities	**512**	467

7. INVENTORIES

	As at	
($ millions)	**September 30, 2011**	December 31, 2010
Gas in storage	**173**	148
Materials and supplies	**21**	20
	194	168

During the three and nine months ended September 30, 2011, inventories of $76 million and $590 million, respectively, were expensed and reported in energy supply costs on the interim consolidated statement of earnings ($90 million and $586 million for the three and nine months ended September 30, 2010, respectively). Inventories expensed to operating expenses were $3 million and $10 million for the three and nine months ended September 30, 2011, respectively ($3 million and $10 million for the three and nine months ended September 30, 2010, 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, 2011, respectively ($2 million and $7 million for the three and nine months ended September 30, 2010, respectively).

8. OTHER ASSETS

	As at	
($ millions)	**September 30, 2011**	December 31, 2010
Deferred pension costs	**139**	140
Other asset - Belize Electricity	**120**	-
Long-term accounts receivable	**9**	9
Other	**16**	19
	284	168

As a result of no longer exercising control over the operations of Belize Electricity, Fortis discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011. The book value of the Corporation's previously 70% controlled foreign net investment in self-sustaining Belize Electricity has been classified as a long-term other asset. The asset is denominated in US dollars and has been translated into Canadian dollars at the exchange rate prevailing at the balance sheet date. Effective June 20, 2011, the Corporation's asset associated with its previous investment in Belize Electricity does not qualify for hedge accounting and, as a result, from June 20, 2011, an approximate $7 million foreign exchange gain on the translation of the asset was recognized in earnings for the three and nine months ended September 30, 2011. As at June 20, 2011, approximately $28 million of unrealized foreign currency translation losses, related to the translation into Canadian dollars of the Corporation's previous foreign net investment in self-sustaining Belize Electricity, were reclassified to long-term other assets from accumulated other comprehensive loss and are included in the $120 million balance as at September 30, 2011 (Note 12).

9. LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS

	As at	
($ millions)	**September 30, 2011**	December 31, 2010
Long-term debt and capital lease obligations	**5,522**	5,489
Long-term classification of committed credit facilities (Note 20)	**114**	218
Deferred debt financing costs	**(41)**	(42)
Total long-term debt and capital lease obligations	**5,595**	5,665
Less: Current installments of long-term debt and capital lease obligations	**(91)**	(56)
	5,504	5,609

10. COMMON SHARES

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

Issued and Outstanding	As at September 30, 2011 Number of Shares *(in thousands)*	September 30, 2011 Amount *($ millions)*	December 31, 2010 Number of Shares *(in thousands)*	December 31, 2010 Amount *($ millions)*
Common shares	**186,934**	**2,973**	174,393	2,578

Common shares issued during the period were as follows:

	Quarter Ended September 30, 2011 Number of Shares *(in thousands)*	Quarter Ended September 30, 2011 Amount *($ millions)*	Year-to-Date September 30, 2011 Number of Shares *(in thousands)*	Year-to-Date September 30, 2011 Amount *($ millions)*
Balance, beginning of period	**185,059**	**2,915**	**174,393**	**2,578**
Public offering	**1,240**	**40**	**10,340**	**331**
Dividend Reinvestment Plan	**529**	**16**	**1,498**	**48**
Consumer Share Purchase Plan	**10**	**-**	**34**	**1**
Stock Option Plans	**96**	**2**	**669**	**15**
Balance, end of period	**186,934**	**2,973**	**186,934**	**2,973**

In June 2011 Fortis publicly issued 9.1 million common shares for $33.00 per share. The common share issue resulted in gross proceeds of approximately $300 million, or approximately $291 million net of after-tax expenses. In July 2011 an additional 1.24 million common shares of Fortis were publicly issued for $33.00 per share, upon the exercise of an over-allotment option, resulting in gross proceeds of approximately $41 million, or approximately $40 million net of after-tax expenses.

Earnings per Common Share

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

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

10. COMMON SHARES (cont'd)

Earnings per Common Share (cont'd)

EPS were as follows:

	Quarter Ended September 30					
	2011			2010		
	Earnings to Common Shareholders *($ millions)*	**Weighted Average Shares *(in millions)***	**EPS**	Earnings to Common Shareholders *($ millions)*	Weighted Average Shares *(in millions)*	EPS
Basic EPS	**58**	**186.5**	**$ 0.31**	45	173.2	$ 0.26
Effect of potential dilutive securities:						
Stock Options	**-**	**1.0**		-	0.9	
Preference Shares (Note 14)	**4**	**10.1**		4	11.9	
Convertible Debentures	**1**	**1.4**		1	1.4	
	63	**199.0**		50	187.4	
Deduct anti-dilutive impacts:						
Preference Shares	**(4)**	**(10.1)**		(4)	(11.9)	
Convertible Debentures	**(1)**	**(1.4)**		(1)	(1.4)	
Diluted EPS	**58**	**187.5**	**$ 0.31**	45	174.1	$ 0.26

	Year-to-Date September 30					
	2011			2010		
	Earnings to Common Shareholders *($ millions)*	**Weighted Average Shares *(in millions)***	**EPS**	Earnings to Common Shareholders *($ millions)*	Weighted Average Shares *(in millions)*	EPS
Basic EPS	**233**	**179.5**	**$ 1.30**	200	172.4	$ 1.16
Effect of potential dilutive securities:						
Stock Options	**-**	**1.0**		-	0.9	
Preference Shares (Note 14)	**12**	**10.1**		12	11.9	
Convertible Debentures	**2**	**1.4**		2	1.4	
	247	**192.0**		214	186.6	
Deduct anti-dilutive impacts:						
Preference Shares	**(12)**	**(10.1)**		-	-	
Diluted EPS	**235**	**181.9**	**$ 1.29**	214	186.6	$ 1.15

11. STOCK-BASED COMPENSATION PLANS

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

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

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

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

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

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

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

As at September 30, 2011, approximately 4.8 million stock options were outstanding and approximately 2.7 million stock options were vested.

12. ACCUMULATED OTHER COMPREHENSIVE LOSS

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

	Quarter Ended September 30					
	2011			2010		
($ 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) gains, net of hedging activities and tax	**(65)**	**8**	**(57)**	(74)	(10)	(84)
Net losses on derivative instruments previously discontinued as cash flow hedges, net of tax	**(4)**	**1**	**(3)**	(5)	1	(4)
Accumulated other comprehensive (loss) income	**(69)**	**9**	**(60)**	(79)	(9)	(88)

	Year-to-Date September 30					
	2011			2010		
($ 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) gains, net of hedging activities and tax	**(90)**	**33**	**(57)**	(78)	(6)	(84)
Net losses on derivative instruments previously discontinued as cash flow hedges, net of tax	**(4)**	**1**	**(3)**	(5)	1	(4)
Accumulated other comprehensive (loss) income	**(94)**	**34**	**(60)**	(83)	(5)	(88)

12. ACCUMULATED OTHER COMPREHENSIVE LOSS (cont'd)

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

13. EMPLOYEE FUTURE BENEFITS

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, OPEB plans, defined contribution pension plans and group registered retirement savings plans ("RRSPs") for its employees. The cost of providing the defined benefit arrangements was $16 million for the quarter ended September 30, 2011 ($10 million for the quarter ended September 30, 2010) and $46 million year-to-date September 30, 2011 ($28 million year-to-date September 30, 2010). The cost of providing the defined contribution arrangements and group RRSPs for the quarter ended September 30, 2011 was $3 million ($3 million for the quarter ended September 30, 2010) and $11 million year-to-date September 30, 2011 ($10 million year-to-date September 30, 2010).

14. FINANCE CHARGES

	Quarter Ended September 30		Year-to-Date September 30	
($ millions)	**2011**	2010	**2011**	2010
Interest - Long-term debt and capital lease obligations	**91**	89	**270**	265
- Short-term borrowings and other	**1**	3	**10**	6
Allowance for funds used during construction	**(6)**	(8)	**(19)**	(17)
Unrealized net foreign exchange gain [(1)]	**(2)**	-	**(2)**	-
Dividends on preference shares classified as debt (Note 10)	**4**	4	**12**	12
	88	88	**271**	266

[(1)] Comprised of a $7 million foreign exchange gain on the translation into Canadian dollars of the Corporation's long-term asset associated with Belize Electricity (Note 8), partially offset by a $5.5 million foreign exchange loss on the translation into Canadian dollars of the Corporation's unhedged US dollar borrowings.

15. CORPORATE TAXES

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

	Quarter Ended September 30		Year-to-Date September 30	
($ millions, except as noted)	**2011**	2010	**2011**	2010
Combined Canadian federal and provincial statutory income tax rate	**30.5%**	32.0%	**30.5%**	32.0%
Statutory income tax rate applied to earnings before corporate taxes	**24**	20	**97**	89
Preference share dividends	**1**	1	**4**	4
Difference between Canadian statutory rate and rates applicable to foreign subsidiaries	**(1)**	(5)	**(9)**	(12)
Difference in Canadian provincial statutory rates applicable to subsidiaries in different Canadian jurisdictions	**(4)**	(2)	**(9)**	(8)
Items capitalized for accounting purposes but expensed for income tax purposes	**(11)**	(9)	**(39)**	(29)
Difference between capital cost allowance and amounts claimed for accounting purposes	**5**	(2)	**11**	(1)
Other	**(2)**	2	**2**	5
Corporate taxes	**12**	5	**57**	48
Effective tax rate	**15.0%**	8.3%	**17.9%**	17.4%

As at September 30, 2011, the Corporation had approximately $62 million (December 31, 2010 - $95 million) in non-capital and capital loss carryforwards, of which $18 million (December 31, 2010 - $18 million) has not been recognized in the consolidated financial statements. The non-capital loss carryforwards expire between 2014 and 2031.

16. SEGMENTED INFORMATION

Information by reportable segment is as follows:

	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
Quarter Ended September 30, 2011 *($ millions)*	**FortisBC Energy Companies - Canadian**	Fortis Alberta	FortisBC Electric	Newfoundland Power	Other Canadian	**Total Electric Canadian**	**Electric [(1)] Caribbean**	**Fortis [(2)] Generation**	**Fortis Properties**	**Corporate [(3)] and Other**	**Inter-segment eliminations**	**Consolidated**
Revenue	**198**	103	67	101	88	**359**	**73**	**11**	**63**	**25**	**(8)**	**721**
Energy supply costs	**76**	-	15	52	56	**123**	**47**	**-**	**-**	**-**	**-**	**246**
Operating expenses	**68**	35	19	17	12	**83**	**8**	**2**	**40**	**3**	**(2)**	**202**
Amortization	**28**	34	11	11	6	**62**	**7**	**1**	**5**	**2**	**-**	**105**
Operating income	**26**	34	22	21	14	**91**	**11**	**8**	**18**	**20**	**(6)**	**168**
Finance charges	**32**	15	10	9	5	**39**	**2**	**-**	**6**	**15**	**(6)**	**88**
Corporate tax (recovery) expense	**(3)**	-	2	4	3	**9**	**-**	**-**	**3**	**3**	**-**	**12**
Net (loss) earnings	**(3)**	19	10	8	6	**43**	**9**	**8**	**9**	**2**	**-**	**68**
Non-controlling interests	**-**	-	-	-	-	**-**	**3**	**-**	**-**	**-**	**-**	**3**
Preference share dividends	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**7**	**-**	**7**
Net (loss) earnings attributable to common equity shareholders	**(3)**	19	10	8	6	**43**	**6**	**8**	**9**	**(5)**	**-**	**58**
Goodwill	**908**	227	221	-	63	**511**	**141**	**-**	**-**	**-**	**-**	**1,560**
Identifiable assets	**4,219**	2,341	1,300	1,211	659	**5,511**	**752**	**519**	**588**	**517**	**(411)**	**11,695**
Total assets	**5,127**	2,568	1,521	1,211	722	**6,022**	**893**	**519**	**588**	**517**	**(411)**	**13,255**
Gross capital expenditures [(4)]	**65**	82	25	24	14	**145**	**17**	**49**	**11**	**-**	**-**	**287**
Quarter Ended September 30, 2010 *($ millions)*												
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	6	**73**	**9**	**2**	**5**	**1**	**-**	**117**
Operating income	**23**	31	19	21	13	**84**	**14**	**9**	**17**	**4**	**(3)**	**148**
Finance charges	**28**	12	7	9	5	**33**	**4**	**-**	**6**	**20**	**(3)**	**88**
Corporate tax expense (recovery)	**-**	-	1	4	3	**8**	**(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	631	**5,102**	**805**	**193**	**580**	**526**	**(423)**	**10,951**
Total assets	**5,076**	2,296	1,441	1,182	694	**5,613**	**943**	**193**	**580**	**526**	**(423)**	**12,508**
Gross capital expenditures [(4)]	**72**	102	36	20	12	**170**	**17**	**4**	**5**	**-**	**-**	**268**

(1) Reflects the discontinuance of the consolidation method of accounting for Belize Electricity from June 20, 2011 (Note 8)

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

(3) Results reflect the $11 million after-tax fee paid to Fortis in July 2011 following upon the termination of the Merger Agreement between Fortis and Central Vermont Public Service Corporation ("CVPS").

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

16. SEGMENTED INFORMATION (cont'd)

	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
Year-to-Date September 30, 2011 *($ millions)*	**FortisBC Energy Companies - Canadian**	Fortis Alberta	FortisBC Electric	Newfoundland Power	Other Canadian	**Total Electric Canadian**	**Electric Caribbean** [(1)]	**Fortis Generation** [(2)]	**Fortis Properties**	**Corporate and Other** [(3)]	**Inter-segment eliminations**	**Consolidated**
Revenue	**1,093**	310	215	417	256	**1,198**	**236**	**25**	**173**	**40**	**(30)**	**2,735**
Energy supply costs	**590**	-	49	266	163	**478**	**146**	**1**	**-**	**-**	**(8)**	**1,207**
Operating expenses	**219**	106	58	54	34	**252**	**31**	**6**	**117**	**7**	**(5)**	**627**
Amortization	**81**	100	34	32	18	**184**	**24**	**3**	**14**	**5**	**-**	**311**
Operating income	**203**	104	74	65	41	**284**	**35**	**15**	**42**	**28**	**(17)**	**590**
Finance charges	**91**	44	28	27	16	**115**	**11**	**1**	**18**	**52**	**(17)**	**271**
Corporate tax expense (recovery)	**24**	1	8	12	7	**28**	**1**	**1**	**6**	**(3)**	**-**	**57**
Net earnings (loss)	**88**	59	38	26	18	**141**	**23**	**13**	**18**	**(21)**	**-**	**262**
Non-controlling interests	**-**	-	-	-	-	**-**	**7**	**-**	**-**	**-**	**-**	**7**
Preference share dividends	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**22**	**-**	**22**
Net earnings (loss) attributable to common equity shareholders	**88**	59	38	26	18	**141**	**16**	**13**	**18**	**(43)**	**-**	**233**
Goodwill	**908**	227	221	-	63	**511**	**141**	**-**	**-**	**-**	**-**	**1,560**
Identifiable assets	**4,219**	2,341	1,300	1,211	659	**5,511**	**752**	**519**	**588**	**517**	**(411)**	**11,695**
Total assets	**5,127**	2,568	1,521	1,211	722	**6,022**	**893**	**519**	**588**	**517**	**(411)**	**13,255**
Gross capital expenditures [(4)]	**179**	253	78	55	33	**419**	**57**	**131**	**20**	**-**	**-**	**806**
Year-to-Date September 30, 2010 *($ millions)*												
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	631	**5,102**	**805**	**193**	**580**	**526**	**(423)**	**10,951**
Total assets	**5,076**	2,296	1,441	1,182	694	**5,613**	**943**	**193**	**580**	**526**	**(423)**	**12,508**
Gross capital expenditures [(4)]	**182**	258	99	56	33	**446**	**53**	**7**	**14**	**1**	**-**	**703**

(1) Reflects the discontinuance of the consolidation method of accounting for Belize Electricity from June 20, 2011 (Note 8)
(2) Results reflect contribution from the Vaca hydroelectric generating facility in Belize, which was commissioned in March 2010, and the Waneta Partnership, which was established in October 2010.
(3) Results reflect the $11 million after-tax fee paid to Fortis in July 2011 following upon the termination of the Merger Agreement between Fortis and CVPS.
(4) Relates to cash payments to acquire or construct utility capital assets, including amounts for AESO transmission-related capital projects, income producing properties and intangible assets, as reflected on the consolidated statement of cash flows

16. SEGMENTED INFORMATION (cont'd)

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

Significant Inter-Segment Transactions	**Quarter Ended September 30**		**Year-to-Date September 30**	
($ millions)	**2011**	2010	**2011**	2010
Sales from Fortis Generation to Regulated Electric Utilities - Caribbean	**-**	11	**7**	19
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**	-	**2**	-
Corporate to Regulated Electric Utilities - Caribbean	**1**	-	**3**	2
Corporate to Fortis Generation	**1**	1	**2**	3
Corporate to Fortis Properties	**3**	2	**9**	8

The significant inter-segment asset balances were as follows:

	As at September 30	
($ millions)	**2011**	2010
Inter-segment borrowings from:		
Corporate to Regulated Electric Utilities - Canadian	**50**	75
Corporate to Regulated Electric Utilities - Caribbean	**78**	57
Corporate to Fortis Generation	**50**	55
Corporate to Fortis Properties	**226**	223
Other inter-segment assets	**7**	13
Total inter-segment eliminations	**411**	423

17. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

	Quarter Ended September 30		**Year-to-Date September 30**	
($ millions)	**2011**	2010	**2011**	2010
Interest paid	**79**	83	**260**	261
Income taxes paid	**16**	8	**61**	45

18. CAPITAL MANAGEMENT

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

18. CAPITAL MANAGEMENT (cont'd)

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

	As at			
	September 30, 2011		December 31, 2010	
	($ millions)	***(%)***	*($ millions)*	*(%)*
Total debt and capital lease obligations (net of cash) [(1)]	**5,729**	**54.8**	5,914	58.4
Preference shares [(2)]	**912**	**8.7**	912	9.0
Common shareholders' equity	**3,809**	**36.5**	3,305	32.6
Total [(3)]	**10,450**	**100.0**	10,131	100.0

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

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

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

As the hydroelectric assets and water rights of the Exploits Partnership had been provided as security for the Exploits Partnership term loan, the expropriation of such assets and rights by the Government of Newfoundland and Labrador constituted an event of default under the loan. The term loan is without recourse to Fortis and was approximately $56 million as at September 30, 2011 (December 31, 2010 - $58 million). The lenders of the term loan have not demanded accelerated repayment. The scheduled repayments under the term loan are being made by Nalcor Energy, a Crown corporation, acting as agent for the Government of Newfoundland and Labrador with respect to expropriation matters. For further information refer to Note 30 to the Corporation's 2010 annual audited consolidated financial statements.

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

19. FINANCIAL INSTRUMENTS

Fair Values

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

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

19. FINANCIAL INSTRUMENTS (cont'd)

	As at			
	September 30, 2011		December 31, 2010	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Waneta Partnership promissory note (1) (2)	**44**	**47**	42	40
Long-term debt, including current portion (3) (4)	**5,595**	**6,728**	5,669	6,431
Preference shares, classified as debt (3) (5)	**320**	**345**	320	344

(1) Included in long-term other liabilities on the consolidated balance sheet
(2) Carrying value is a discounted present value.
(3) Carrying value is measured at amortized cost using the effective interest rate method.
(4) Carrying value as at September 30, 2011 excludes unamortized deferred financing costs of $41 million (December 31, 2010 - $42 million) and capital lease obligations of $41 million (December 31, 2010 - $38 million).
(5) Preference shares classified as equity do not meet the definition of a financial instrument; however, the estimated fair value of the Corporation's $592 million preference shares classified as equity was $616 million as at September 30, 2011 (December 31, 2010 – $615 million).

Excluded from the above table is the $120 million long-term other asset as at September 30, 2011 related to the Corporation's previous investment in Belize Electricity. The fair value of this financial asset is not determinable at this time.

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

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

	As at					
	September 30, 2011				December 31, 2010	
Liability	**Term to Maturity *(years)***	**Number of Contracts**	**Carrying Value *($ millions)***	**Estimated Fair Value *($ millions)***	Carrying Value *($ millions)*	Estimated Fair Value *($ millions)*
Foreign exchange forward contract (1)	**< 1**	**1**	**-**	**-**	-	-
Fuel option contracts (1) (2)	**< 1**	**2**	**(1)**	**(1)**	-	-
Natural gas derivatives: (1) (2)						
Swaps and options	**Up to 3**	**201**	**(101)**	**(101)**	(162)	(162)
Gas purchase contract premiums	**Up to 2**	**85**	**(3)**	**(3)**	(5)	(5)

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

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

20. FINANCIAL RISK MANAGEMENT

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

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

Credit Risk

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

FortisAlberta has a concentration of credit risk as a result of its distribution service billings being to a relatively small group of retailers. As at September 30, 2011, the utility's gross credit risk exposure was approximately $140 million, representing the projected value of retailer billings over a 60-day period. The Company has reduced its exposure to approximately $6 million by obtaining from the retailers either a cash deposit, bond, letter of credit or an investment grade credit rating from a major rating agency, or by having the retailer obtain a financial guarantee from an entity with an investment grade credit rating.

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

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

($ millions)	**September 30, 2011**	June 30, 2011	March 31, 2011	December 31, 2010	September 30, 2010
Not past due	**396**	488	601	584	399
Past due 0-30 days	**46**	67	76	56	29
Past due 31-60 days	**14**	20	15	9	9
Past due 61 days and over	**13**	14	8	6	6
	469	589	700	655	443

Effective June 30, 2011, the aging analysis includes amounts owed to Belize Electric Company Limited ("BECOL") from Belize Electricity, due to the discontinuance of the consolidation method of accounting for Belize Electricity.

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

20. FINANCIAL RISK MANAGEMENT (cont'd)

Liquidity Risk

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

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

The Corporation's committed credit facility is available for interim financing of acquisitions and for general corporate purposes. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends. As at September 30, 2011, average annual consolidated long-term debt maturities and repayments over the next five years are expected to be approximately $270 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, 2011, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.3 billion, of which $1.9 billion was unused. The credit facilities are syndicated mostly with the seven largest Canadian banks, with no one bank holding more than 20% 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, 2011**	December 31, 2010
Total credit facilities	845	1,490	13	**2,348**	2,109
Credit facilities utilized:					
Short-term borrowings	-	(239)	(3)	**(242)**	(358)
Long-term debt (Note 9) [(1)]	-	(114)	-	**(114)**	(218)
Letters of credit outstanding	(1)	(65)	-	**(66)**	(124)
Credit facilities unused	844	1,072	10	**1,926**	1,409

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

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

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

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

20. FINANCIAL RISK MANAGEMENT (cont'd)

Liquidity Risk (cont'd)

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

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

In August 2011 the Corporation renegotiated and amended its unsecured committed revolving credit facility, increasing the amount available under the facility to $800 million from $600 million and extending the maturity date of the facility to July 2015 from May 2012. At any time prior to maturity, the Corporation may provide written notice to increase the amount available under the facility to $1 billion. The amended credit facility agreement reflects an increase in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

In September 2011 FortisAlberta amended its unsecured committed revolving credit facility to increase the amount available under the facility to $250 million from $200 million and extend the maturity date to September 2015 from May 2012. The amended credit facility agreement reflects an increase in pricing.

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

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

During the third quarter of 2011, DBRS confirmed the Corporation's existing debt credit rating at A(low). The credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level, the Corporation's reasonable credit metrics and its demonstrated ability and continued focus on acquiring and integrating stable regulated utility businesses financed on a conservative basis.

20. FINANCIAL RISK MANAGEMENT (cont'd)

Liquidity Risk (cont'd)

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

Financial Liabilities *($ millions)*	Due within 1 year	Due in years 2 and 3	Due in years 4 and 5	Due after 5 years	**Total**
Short-term borrowings	242	-	-	-	**242**
Trade and other accounts payable	748	-	-	-	**748**
Natural gas derivatives [(1)]	63	27	1	-	**91**
Fuel option contracts [(2)]	1	-	-	-	**1**
Foreign exchange forward contract [(3)]	5	-	-	-	**5**
Dividends payable	58	-	-	-	**58**
Customer deposits [(4)]	-	3	1	2	**6**
Waneta Partnership promissory note [(5)]	-	-	-	72	**72**
Long-term debt, including current portion [(6)]	88	439	817	4,251	**5,595**
Interest obligations on long-term debt	346	677	588	4,886	**6,497**
Preference shares, classified as debt	-	123	197	-	**320**
Dividend obligations on preference shares, classified as finance charges	17	26	20	-	**63**
	1,568	1,295	1,624	9,211	**13,698**

[(1)] Amounts disclosed are on a gross cash flow basis. The derivatives were recorded in accounts payable at fair value as at September 30, 2011 at $104 million.
[(2)] Amounts disclosed are on a gross cash flow basis. The contracts were recorded in accounts payable at fair value as at September 30, 2011 at $1 million.
[(3)] Amounts disclosed are on a gross cash flow basis. The contract was recorded in accounts receivable at fair value as at September 30, 2011 at less than $1 million.
[(4)] Customer deposits were recorded in long-term other liabilities as at September 30, 2011.
[(5)] Amounts disclosed are on a gross cash flow basis. The promissory note was recorded in long-term other liabilities at present value as at September 30, 2011 at $44 million.
[(6)] Excludes deferred debt financing costs of $41 million and capital lease obligations of $41 million

Market Risk

Foreign Exchange Risk

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

As at September 30, 2011, US$550 million of the US$590 million corporately issued long-term debt (December 31, 2010 - US$590 million of US$590 million) had been designated as an effective hedge of the Corporation's net investments in self-sustaining foreign subsidiaries. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar borrowings designated as effective hedges are recognized in other comprehensive income and help offset unrealized foreign currency exchange gains and losses on the net investments in self-sustaining foreign subsidiaries, which are also recognized in other comprehensive income.

20. FINANCIAL RISK MANAGEMENT (cont'd)

Market Risk (cont'd)

Foreign Exchange Risk (cont'd)

Effective June 20, 2011, the Corporation's asset associated with its previous investment in Belize Electricity (Note 8) does not qualify for hedge accounting as Belize Electricity is no longer a self-sustaining foreign subsidiary of Fortis. As a result, as at September 30, 2011, approximately US$40 million of corporately issued debt that previously hedged the former investment in Belize Electricity is no longer an effective hedge. Effective from June 20, 2011, foreign exchange gains and losses on the translation of the asset associated with Belize Electricity and the corporately issued US dollar denominated debt that previously qualified as a hedge of the investment are required to be recognized in earnings. As a result, the Corporation recognized a net after-tax foreign exchange gain of approximately $2.5 million in earnings during the quarter ended September 30, 2011. As at September 30, 2011, all of the Corporation's net investments in self-sustaining foreign subsidiaries were hedged (December 31, 2010 - 99%).

FEI and FEVI's US dollar payments under contracts for the implementation of a customer information system and the construction of a liquefied natural gas ("LNG") storage facility, respectively, have exposed the utilities to fluctuations in the US dollar-to-Canadian dollar exchange rate. FEI and FEVI had 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. During the third quarter of 2011, FEVI's foreign exchange forward contract related to payments required in US dollars associated with the construction of the LNG storage facility matured.

Interest Rate Risk

The Corporation and its subsidiaries are exposed to interest rate risk associated with credit facility borrowings and floating-rate debt. The Corporation and its subsidiaries may enter into interest rate swap agreements to help reduce this risk.

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

Commodity Price Risk

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

The price risk-management strategy of the FortisBC Energy companies aims to improve the likelihood that natural gas prices remain competitive, to temper gas price volatility on customer rates and reduce the risk of regional price discrepancies. In January 2011 FEI filed a report of its review to its Price Risk Management Plan ("PRMP") objectives with the British Columbia Utilities Commission ("BCUC") related to its gas commodity hedging plan and also submitted a revised 2011-2014 PRMP. In July 2011 the BCUC issued its decision on FEI's report and determined that commodity hedging in the current environment was not a cost effective means of meeting the objectives of price competitiveness and rate stability. The BCUC concurrently denied FEI's 2011-2014 PRMP with the exception of certain elements to address regional price discrepancies. As a result, FEVI and FEI have suspended commodity-hedging activities with the exception of limited swaps as permitted by the BCUC. The existing hedging contracts are expected to continue in effect through to their maturity and the gas utilities' ability to fully recover the commodity cost of gas in customer rates remains unchanged.

20. FINANCIAL RISK MANAGEMENT (cont'd)

Market Risk (cont'd)

Commodity Price Risk (cont'd)

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

21. CONTINGENT LIABILITIES AND COMMITMENTS

Contingent Liabilities

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

Commitments

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

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

During the first half of 2011, the actuarial valuation of the defined benefit pension plans at the FortisBC Energy companies, covering unionized employees, and at FortisBC Electric were completed. As a result of the actuarial valuations and other revised actuarial estimates, the total estimate of consolidated defined benefit pension funding contributions over the next five years, net of payments made year-to-date September 30, 2011, has increased by approximately $34 million from that disclosed in the Corporation's 2010 annual audited consolidated financial statements. The increase in funding contributions is expected to be recovered from customers in future rates.

22. SUBSEQUENT EVENTS

On October 5, 2011, Newfoundland Power received proceeds of approximately $46 million from Bell Aliant upon the closing of the sale of 40% of Newfoundland Power's joint-use poles (Note 5).

On October 18, 2011, Fortis Properties acquired the 160-room, full-service Hilton Suites Winnipeg Airport hotel for an aggregate cash purchase price of approximately $25 million.

On October 19, 2011, FortisAlberta issued 30-year $125 million 4.54% unsecured debentures. The proceeds of the debt offering were mainly used to repay borrowings under the Company's credit facility incurred to finance capital expenditures, and for general corporate purposes.

23. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to comply with current period presentation. The most significant changes related to: (i) a $48 million decrease for the nine months ended September 30, 2010 in cash from operating activities associated with changes in non-cash operating working capital and a corresponding decrease in cash used in financing activities associated with dividends on common shares; (ii) a $15 million and $43 million decrease for the three and nine months ended September 30, 2010, respectively, in cash from financing activities associated with the issuance of common shares and a corresponding decrease in cash used in financing activities associated with dividends paid on common shares; and (iii) a $17 million increase in long-term regulatory assets and a corresponding $17 million decrease in utility capital assets associated with a change in presentation at the FortisBC Energy companies.

Dates – Dividends* and Earnings

<u>Expected Earnings Release Dates</u>

February 9, 2012	May 2, 2012
July 31, 2012	November 1, 2012

<u>Dividend Record Dates</u>

November 14, 2011	February 10, 2012
May 11, 2012	August 17, 2012

<u>Dividend Payment Dates</u>

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

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

<u>Registrar and Transfer Agent</u>

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<u>Share Listings</u>

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		
	2011	**2010**
High	**33.78**	**32.39**
Low	**28.24**	**26.83**
Close	**32.93**	**31.94**