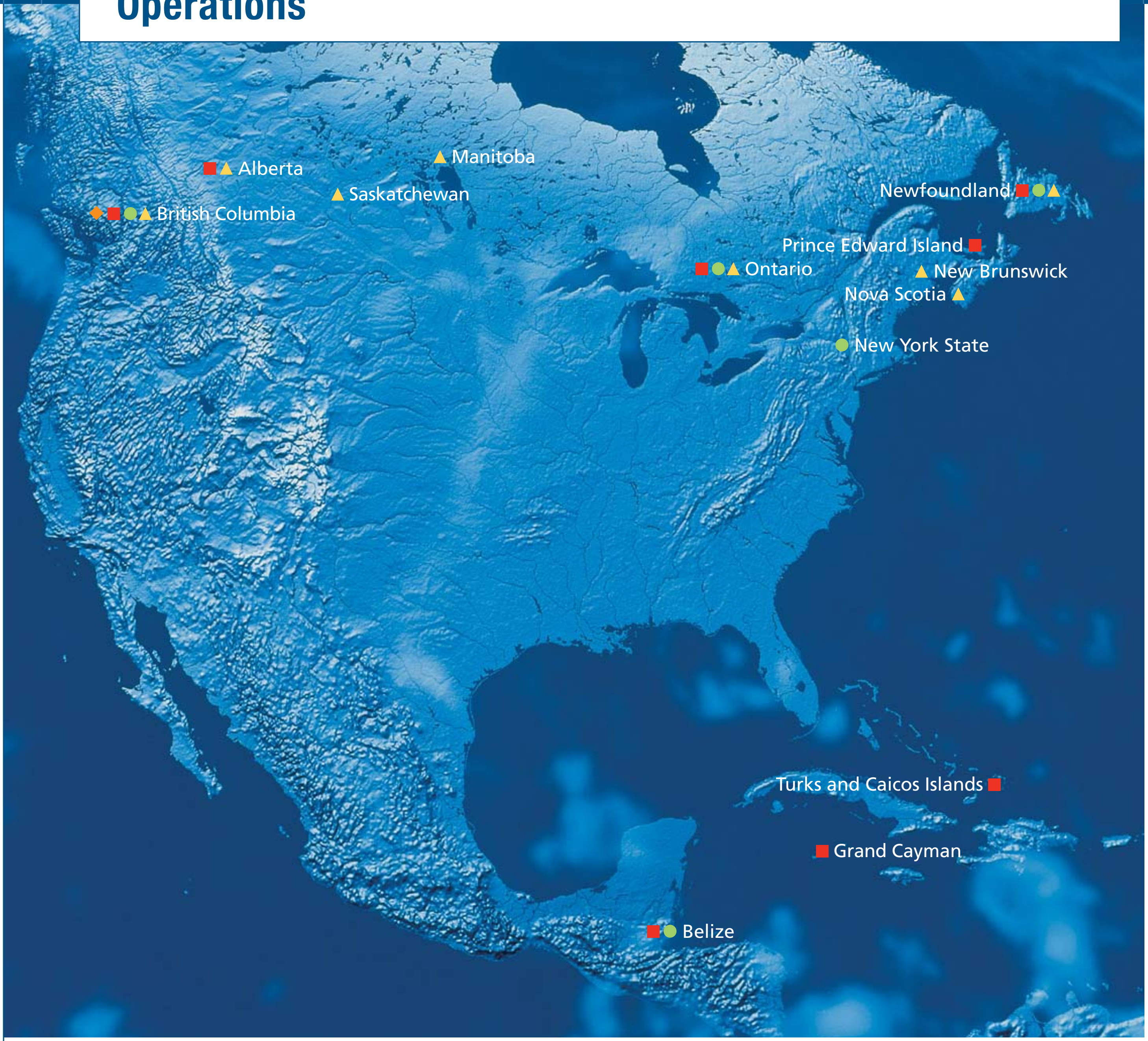
FORTIS INC.

2009 ANNUAL REPORT

Operations



Regulated Utility Operations

Gas Operations ◆

Terasen *British Columbia*

Electric Operations ■

FortisAlberta *Alberta*

FortisBC *British Columbia*

Newfoundland Power *Newfoundland*

Maritime Electric *Prince Edward Island*

FortisOntario *Ontario*

Belize Electricity *Belize*

Caribbean Utilities *Grand Cayman*

Fortis Turks and Caicos *Turks and Caicos Islands*

Non-Regulated Operations

Fortis Generation ●

Production Areas

Belize, Ontario, Central Newfoundland, British Columbia, New York State

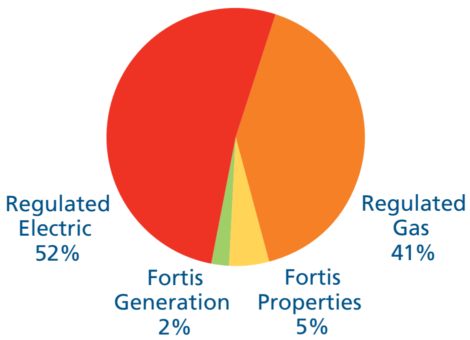
Fortis Properties ▲

Real Estate and Hotels

Across Canada

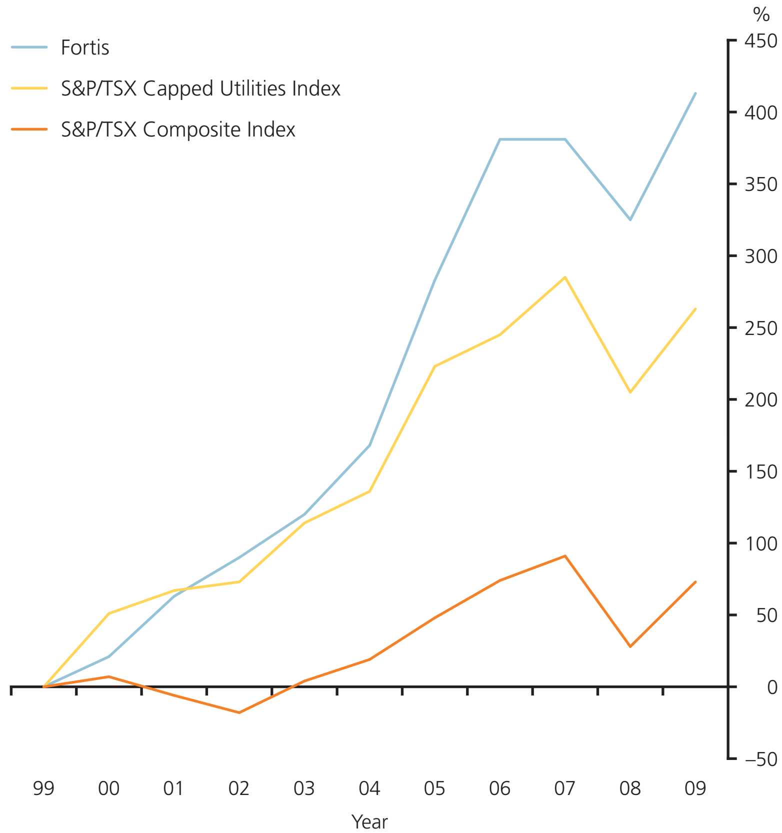
Total Assets Exceed $12 Billion

(as at December 31, 2009)



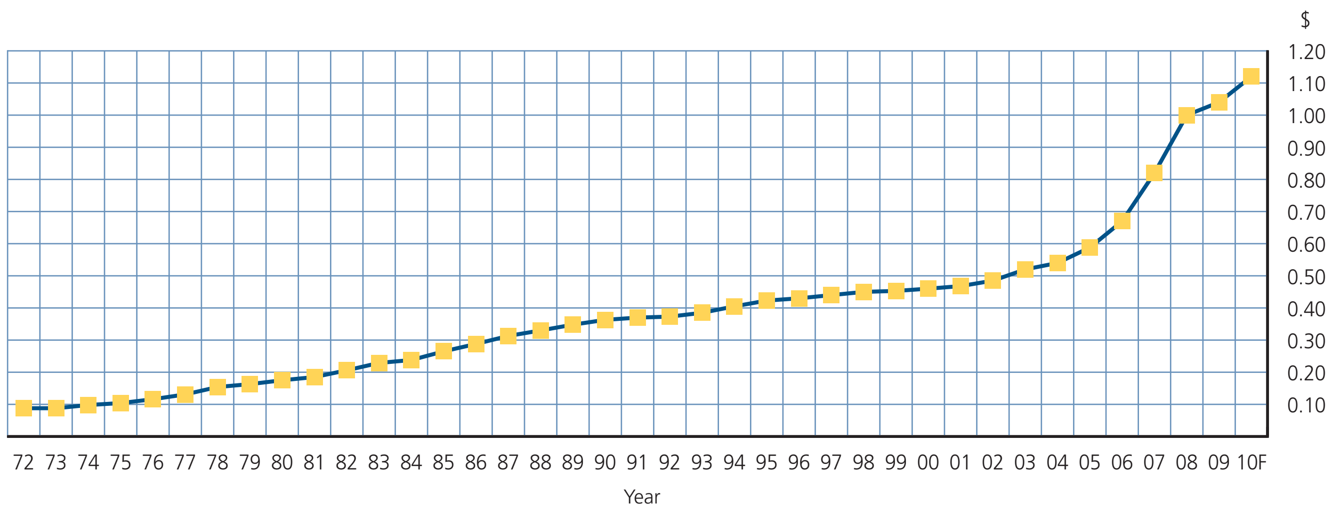
Contents

10-Year Cumulative Total Return



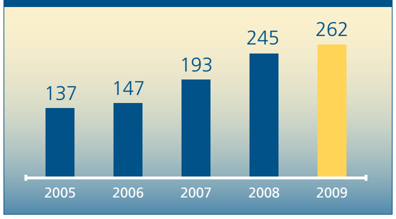
Dividends paid per common share

Fortis has increased its annual dividend to common shareholders for 37 consecutive years, the longest record of any public corporation in Canada.



Investor Highlights

Earnings ($M)

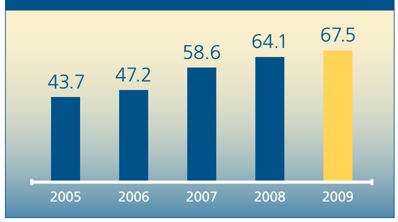


Basic Earnings per Common Share ($)

Diluted Earnings per Common Share ($)

Dividends Paid per Common Share ($)

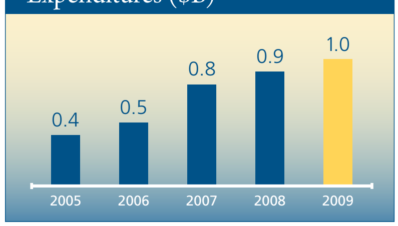
Dividend Payout Ratio (%)



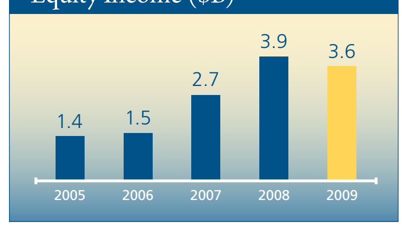
Return on Average Book Common Shareholders' Equity (%)

Assets ($B)

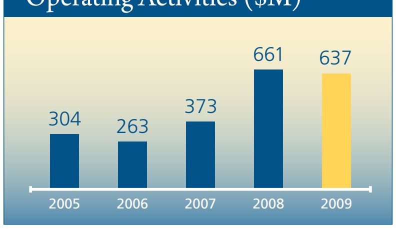
Capital Expenditures ($B)



Revenue and Equity Income ($B)

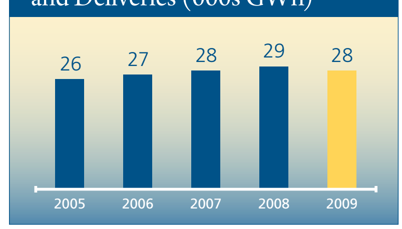


Cash Flow from Operating Activities ($M)



Debt to Total Capitalization (%)

Electricity Sales and Deliveries (000s GWh)



All financial information is presented in Canadian dollars.

Information is for the fiscal year ended December 31, 2009 unless otherwise indicated.

Regulated

Gas

Terasen[1]	Customers (#)	Employees (#)	Peak Day Demand (TJ)	Gas Volumes (PJ)	Capital Program ($M)	Total Assets ($B)	Rate Base ($B)[2]	Earnings ($M)	Allowed ROE (%)[3] 2009	Allowed ROE (%)[3] 2010
Total	**940,000**	**1,295**	**1,234**	**207**	**246**	**5.0**	**3.1**	**117**	**9.50[4]**	**9.50**

Electric

Company	Customers (#)	Employees (#)	Peak Demand (MW)	Energy Sales (GWh)	Capital Program ($M)	Total Assets ($B)	Rate Base ($B)[2]	Earnings ($M)	Allowed ROE (%)[3] 2009	Allowed ROE (%)[3] 2010
FortisAlberta	480,000	996	3,365	15,865	407	2.1	1.6	60	9.00	9.00
FortisBC	159,000	540	714	3,157	115	1.4	1.0	37	8.87	9.90
Newfoundland Power	239,000	568	1,219	5,299	74	1.2	0.9	32	8.95	9.00
Maritime Electric	74,000	179	219	1,032	30	0.4	0.3	11	9.75	9.75[5]
FortisOntario	64,000	184	265	1,163	16	0.2	0.2	9	8.01/8.57[6]	9.75[7]
Belize Electricity[8]	76,000	292	76	417	24	0.2	0.2	4	10.00[9]	[9][10]
Caribbean Utilities[11]	25,000	196	98	558	45	0.5	0.4	12	9.00–11.00[9]	7.75–9.75[9]
Fortis Turks and Caicos	9,000	105	30	165	23	0.2	0.1	11	17.50[9][12]	17.50[9]
Total	**1,126,000**	**3,060**	**5,986**	**27,656**	**734**	**6.2**	**4.7**	**176**		

(1) Includes the operations of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc., collectively known as the "Terasen Gas companies"
(2) Forecast mid-year 2010
(3) Rate of return on common shareholders' equity ("ROE"). For Terasen, ROE is for Terasen Gas Inc. Effective July 1, 2009, ROE for Terasen Gas (Vancouver Island) Inc. is 50 basis points higher; prior to July 1, 2009, ROE was 70 basis points higher.
(4) Effective July 1, 2009; 8.47% prior to July 1, 2009
(5) Subject to regulatory approval
(6) Canadian Niagara Power 8.01%; Algoma Power 8.57%
(7) Subject to Canadian Niagara Power filing a full cost of service application in 2010
(8) Information in table represents 100% of Belize Electricity's operations except for earnings data. Earnings represent Belize Electricity's contribution to consolidated earnings of Fortis, based on the Corporation's 70.1% ownership interest.
(9) Regulated rate of return on rate base assets ("ROA")
(10) Allowed ROA to be settled once regulatory matters are resolved.
(11) Information in table represents 100% of Caribbean Utilities' operations except for earnings data. Earnings represent Caribbean Utilities' contribution to consolidated earnings of Fortis, based on the Corporation's 59% ownership interest.
(12) 2009 achieved ROA was materially lower than the ROA allowed under the licence due to significant investment occurring at the utility.

Non-Regulated

Fortis Generation[1]

	Generating Capacity (MW)	Energy Sales (GWh)	Assets[3] ($B)	Earnings[4] ($M)	Capital Program ($M)
Total	**139**	**583**	**0.4**	**16**	**18**

Fortis Properties[2]

	Employees (#)	Assets ($B)	Earnings[4] ($M)	Capital Program ($M)
Total	**2,300**	**0.6**	**24**	**26**

(1) Includes operations in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State, including the 19-MW Vaca hydroelectric generating facility in Belize, which will be commissioned in March 2010
(2) Includes approximately 2.8 million square feet of commercial office and retail space primarily in Atlantic Canada and 21 hotels across Canada
(3) Includes $130 million in "Other" non-regulated assets
(4) Contribution to consolidated earnings of Fortis for the fiscal year ended December 31, 2009

Information is for the fiscal year ended December 31, 2009 unless otherwise indicated.

Report to Shareholders

2009 was another successful year and marks a successful decade for your company.

For the 10th consecutive year, Fortis has delivered record earnings. Net earnings applicable to common shares were $262 million, $17 million higher than earnings of $245 million in 2008. Earnings per common share were $1.54 in 2009 compared to $1.56 in 2008. In 2000, your company earned $37 million and earnings per common share were $0.68.

Dividends paid per common share grew to $1.04 in 2009, up 4 per cent from $1.00 paid per common share in 2008. In 2000, dividends paid per common share were 46 cents, after giving effect to the 4-for-1 common share stock split that occurred in 2005. Fortis increased its quarterly common share dividend to 28 cents, commencing with the first quarter dividend paid in 2010. The 7.7 per cent increase in the quarterly common share dividend translates into an annualized dividend of $1.12 and extends the Corporation's record of annual common share dividend increases to 37 consecutive years, the longest record of any public corporation in Canada.

Stan Marshall, President and CEO, Fortis Inc. (left) and Geoffrey F. Hyland, Chair of the Board, Fortis Inc. (right).

Over the past 10 years, Fortis delivered an average annualized total return to shareholders of approximately 18 per cent, the highest in our sector. The Corporation's average annualized total return also exceeded the S&P/TSX Capped Utilities Index and S&P/TSX Composite Index, which delivered average annualized performance of approximately 14 per cent and 6 per cent, respectively, over the same period.

In the past two decades, Fortis has diversified beyond Newfoundland Power to become the largest investor-owned distribution utility in Canada, with regulated electric utility operations in five provinces across Canada and three Caribbean countries and regulated natural gas utility operations in British Columbia. Over the past decade, our customer base has grown from approximately 350,000 to 2,100,000; our common share market capitalization has increased from approximately $412 million to almost $5 billion; and our total assets have increased from approximately $1.2 billion to surpass $12 billion.

FortisAlberta's Automated Meter Infrastructure Project enables customers to better monitor and manage their energy consumption.

Fortis utilities continue to make the investments necessary to provide customers with safe, reliable energy at the lowest reasonable cost. Our capital program surpassed $1 billion in 2009, the largest annual capital program ever undertaken by Fortis. Approximately 75 per cent of this capital investment occurred at our regulated utilities in western Canada. Terasen Gas (Vancouver Island) made significant progress with the construction of its approximate $200 million liquefied natural gas storage facility, which is scheduled to come into service in 2011. FortisBC started construction of its $110 million Okanagan Transmission Reinforcement Project, the largest capital initiative ever undertaken by the utility. It is scheduled for completion by mid-2011. FortisAlberta continues work under its multi-year $155 million Automated Meter Infrastructure Project, with approximately 260,000 electronic meters installed at customer sites to date.

The US$53 million 19-megawatt ("MW") hydroelectric generating facility at Vaca in Belize will be commissioned in March 2010. No further investment in Belize is planned.

The global economic downturn and the busiest regulatory calendar in the history of Fortis made 2009 a challenging year. Strong performance from our regulated utilities in western Canada was tempered by the expiry in April of the 100-year water rights of the Rankine hydroelectric generating facility in Ontario and ongoing regulatory challenges in Belize.

A number of significant regulatory decisions received in the fourth quarter of 2009 should provide regulatory stability for 2010, enabling our utilities to focus on operations and meeting the energy needs of our customers.

Effective January 1, 2009, the allowed rate of return on common shareholder's equity ("ROE") at FortisAlberta increased to 9.00 per cent from an interim allowed ROE for 2009 of 8.51 per cent and the utility's equity component of total capital structure ("equity component") increased to 41 per cent from 37 per cent. Effective July 1, 2009, the allowed ROE at Terasen Gas Inc. increased to 9.50 per cent from 8.47 per cent. Effective January 1, 2010, the equity component of Terasen Gas increased to 40 per cent from 35 per cent. The Company also received regulatory approval of a negotiated settlement agreement for its 2010–2011 revenue requirements. A previous agreement had provided for the sharing of earnings above or below the allowed ROE with customers. The recently approved negotiated settlement agreement does not include an earnings sharing mechanism. At FortisBC, the allowed ROE increased to 9.90 per cent from 8.87 per cent, effective January 1, 2010. FortisBC also received regulatory approval of a negotiated settlement agreement for its 2010 revenue requirements. Newfoundland Power received regulatory approval for its 2010 revenue requirements and the Company's allowed ROE has been set at 9.00 per cent for 2010, up from 8.95 per cent for 2009.

The Terasen Gas (Vancouver Island) liquefied natural gas storage facility is scheduled to come into service in 2011.

The Terasen Gas companies delivered earnings of $117 million for 2009 compared to $118 million for 2008. Results for 2009 were constrained by increased costs of approximately $5 million after tax associated with the conversion of Whistler customer appliances from propane to natural gas. Regulatory approval is being sought to include the additional conversion costs in rate base. Results for 2008 were favourably impacted by an approximate $5.5 million tax reduction related to the settlement of historical corporate tax matters. Excluding these two items, earnings were $9.5 million higher year over year, mainly due to the impact of the higher allowed ROE, effective July 1, 2009, and lower effective corporate taxes.

The annual capital program of Fortis surpassed a record $1 billion in 2009.

Earnings at Canadian Regulated Electric Utilities were $149 million, up $23 million from $126 million for 2008. Excluding a one-time favourable $3 million corporate tax adjustment at FortisOntario in 2009 and a one-time $2 million charge at FortisOntario associated with the repayment of an interconnection agreement-related refund during 2008, earnings were $18 million higher year over year. Results were driven by the higher allowed ROE and increased equity component at FortisAlberta combined with rate base growth at FortisAlberta and FortisBC.

FortisOntario acquired Great Lakes Power Distribution Inc., subsequently renamed Algoma Power Inc., in October for an aggregate purchase price of approximately $75 million. The utility serves approximately 12,000 customers in the District of Algoma in northern Ontario. The acquisition makes Fortis the only investor-owned electric distribution utility in Ontario.

Earnings at Caribbean Regulated Electric Utilities were $27 million compared to $17 million for 2008. Results for 2008 reflected a $13 million reduction in earnings related to a June 2008 regulatory decision at Belize Electricity but included $1.5 million of additional earnings from Caribbean Utilities related to a change in the utility's fiscal year end in 2008. Excluding these two items, earnings were $1.5 million lower year over year. The decrease was mainly due to the impact of a lower allowed rate of return on rate base assets at Belize Electricity for the entire year in 2009 compared to half a year in 2008 and higher operating costs. The decrease was partially offset by the favourable impact of a change in the methodology for calculating the cost of fuel recoverable from customers and a change in depreciation estimates at Fortis Turks and Caicos as well as the favourable impact of foreign currency translation. Results reflected slower electricity sales growth as a result of the negative impact of the global economic downturn. Annualized electricity sales growth was approximately 2 per cent for 2009 compared to 6 per cent for 2008.

Regulatory challenges are ongoing in Belize where Belize Electricity is legally contesting several decisions of its regulator. The Company's appeal of the June 2008 decision commenced in court in October 2009.

Earnings at Non-Regulated Fortis Generation were $16 million compared to $30 million for 2008. The decrease was mainly due to the lower contribution from the Rankine hydroelectric generating facility combined with lower average wholesale market energy prices and lower production in Upper New York State.

Earnings at Fortis Properties were $24 million compared to $23 million for 2008. Contributions from recently acquired hotels and the Real Estate Division and lower finance charges were partially offset by generally lower occupancies at the remainder of the Company's hotels as a result of the economic downturn.

Fortis and its four largest utilities have strong investment-grade credit ratings. In September, Standard & Poor's confirmed its credit rating for Fortis at A– (stable outlook), reflecting the diversity of the Corporation's regulated utility operations, the stability and predictability of the utilities' cash flows, and the Corporation's focused, well-executed growth strategy. Fortis is rated BBB (high) by DBRS.

Notwithstanding the severe global economic downturn and capital market volatility, Fortis and its utilities have raised approximately $1.3 billion in the capital markets since late 2008, demonstrating the financial strength of our core utility business. In December 2008, we completed a $300 million common share issue. In 2009, we issued more than $700 million of long-term debt, including 30-year $200 million 6.51% unsecured debentures at Fortis, 30-year $495 million long-term debt at rates ranging from 5.37% to 7.06% at our Canadian Regulated Utilities and 15-year US$40 million 7.50% long-term debt at Caribbean Utilities. In January 2010, Fortis issued $250 million five-year fixed rate reset preference shares with an initial annualized dividend of 4.25%.

Fortis, through its regulated and non-regulated businesses, owns and/or operates 1,840 MW of generation, mainly hydroelectric.

Report to Shareholders

The Corporation's long-term debt maturities and repayments, as at December 31, 2009, are expected 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 provides the Corporation and its subsidiaries with flexibility in the timing of access to the debt and equity capital markets.

At December 31, 2009, Fortis had consolidated credit facilities of approximately $2.2 billion, of which approximately $1.4 billion was unused, including $476 million unused under the Corporation's $600 million committed revolving credit facility. Approximately $2.0 billion of the total credit facilities are committed facilities, the majority of which have maturities between 2011 and 2013. The credit facilities are syndicated almost entirely with the seven largest Canadian banks, with no one bank holding more than 25 per cent of these facilities.

Over the next five years, capital expenditures are expected to approach $5 billion.

The commitment of Fortis employees, now almost 6,700 people strong, to deliver quality service to our customers continues to power our performance. Congratulations to each and every one of you on achieving another successful year. We welcome Messrs. Douglas Haughey and Ronald Munkley and Ms. Ida Goodreau who joined our Board this year. We extend our gratitude to each of our Board members for their guidance and support.

We continue to build boldly. Our 2010 capital program of more than $1 billion is well underway. Over the next five years, capital expenditures are expected to approach $5 billion, driven by ongoing investment in infrastructure at our regulated utilities in western Canada.

As a new decade begins to unfold, we are excited about the future growth prospects for your company. We will continue to build our business profitably through investment in our existing operations and the acquisition of regulated electric and natural gas utilities in the United States, Canada and the Caribbean.

On behalf of the Board of Directors,

Geoffrey F. Hyland
Chair of the Board
Fortis Inc.

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

The vision of Fortis is to be the world leader in those segments of the regulated utility industry in which it operates and the leading service provider within its service areas. In all its operations, Fortis will manage resources prudently and deliver quality service to maximize value to customers and shareholders.

The Corporation will continue to focus on three primary objectives:

i) The growth in assets and market capitalization should be greater than the average of other North American public gas and electric utilities of similar size.

ii) Earnings should continue at a rate commensurate with that of a well-run North American utility.

iii) The financial and business risks of Fortis should not be substantially greater than those associated with the operation of a North American utility of similar size.

Terasen Inc. ("Terasen") is the largest distributor of natural gas in British Columbia, serving approximately 940,000 customers or 96 per cent of gas users in the province. The Company delivers more than 20 per cent of the total energy consumed in British Columbia, comparable to the amount of electricity used in the province, making it a significant contributor to the province's energy mix.

Terasen's regulated natural gas and piped-propane transmission and distribution business is carried out by Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGWI"), collectively known as the Terasen Gas companies. Its operations also include Terasen Energy Services, which finances, designs, owns and operates geoexchange systems, community piping and energy-transfer systems to harness renewable energy sources.

Officers of Terasen (l-r): Jan Marston, VP, HR and Operations Governance; Dwain Bell, VP, Distribution; Cynthia Des Brisay, VP, Gas Supply and Transmission; Bob Samels, VP, Business Services and Technology; Randy Jespersen, President and CEO; Roger Dall'Antonia, VP, Corporate Development and Treasurer; David Bennett, VP and General Counsel; Scott Thomson, VP, Regulatory Affairs and CFO; Doug Stout, VP, Marketing and Business Development

TGI, the largest subsidiary of Terasen, provides natural gas transmission and distribution services and propane distribution to approximately 839,000 customers. Its service territory extends from Vancouver to the Fraser Valley and the interior of British Columbia. TGVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island and the distribution system on Vancouver Island and along the Sunshine Coast. The Company serves approximately 98,000 customers. TGWI owns and operates the natural gas distribution system in the Resort Municipality of Whistler ("Whistler"), providing service to approximately 2,600 customers.

The Terasen Gas companies own and operate more than 46,000 kilometres of natural gas distribution and transmission pipelines. In 2009, gas volumes were 207,230 terajoules ("TJ") and a peak day demand of 1,234 TJ was met.

Terasen achieved a record Customer Satisfaction Rating of 80 per cent in 2009. Residential customers gave improved ratings for emergency and non-emergency services, as well as marketing and communication initiatives.

The approximate $27 million Fraser River South Bank South Arm Rehabilitation Project is expected to be in service by the end of August 2010.

The Terasen Gas companies invested approximately $246 million, before customer contributions, in capital programs in 2009 to ensure the safe, reliable delivery of piped energy to customers.

Construction continued on the approximate $200 million 1.5 billion-cubic foot Mount Hayes liquefied natural gas storage facility on Vancouver Island. When it comes into service, expected in 2011, the facility will allow for more efficient use of existing pipeline systems and improve reliability and security of supply during periods of system interruptions or increased energy demand. Construction of the 50-kilometre natural gas pipeline from Squamish to Whistler and conversion of Whistler to natural gas from propane was completed in 2009 at a total project cost of $56 million. More than 14,000 appliances were converted to natural gas, which will result in a 15 per cent reduction in annual greenhouse gas ("GHG") emissions by natural gas customers and a 5 per cent reduction in annual GHG emissions by the region. An approximate $27 million pipeline upgrade below the south arm of the Fraser River to maintain the integrity of these infrastructure assets is expected to be completed by the end of August 2010.

Terasen continued work on the Village of Fraser Mills district energy system in Coquitlam, the Beedie Group's largest sustainable development project. The district energy system could potentially displace up to 8,200 tonnes of GHG emissions annually–the equivalent of removing 2,500 cars from the road.

FortisAlberta

Officers of FortisAlberta (l-r): Alan Skiffington, VP, Business Services and CIO; Nipa Chakravarti, VP, Customer Service; Ian Lorimer, VP, Finance and CFO; Karl Smith, President and CEO; Phonse Delaney, VP, Operations and Engineering; Annette Butt, VP, Human Resources and Corporate Communications

FortisAlberta is an electric utility that distributes electricity generated by other market participants to end-use customers in southern and central Alberta. Its electricity system includes approximately 110,000 kilometres of distribution lines, which comprise more than 60 per cent of Alberta's total electricity distribution network. The Company serves approximately 480,000 customers and met a record peak demand of 3,365 MW in 2009.

A Customer Satisfaction Rating of 83 per cent was achieved in 2009 compared to an average annual rating of 80 per cent for the previous three years. Customer Contact Centre staff handled approximately 194,000 calls in 2009. Employees resolved 87 per cent of customer concerns during the initial contact.

A record $407 million, before customer contributions, was invested in capital projects in 2009 to maintain the system, install automated meters and meet customer growth. More than 10,000 new customers were connected to the utility's distribution system, including several large and complex business operations such as the CrossIron Mills shopping mall near Balzac and TransCanada's Keystone Pipeline in Hardisty. Approximately 3,000 kilometres of power lines were added to the distribution system. Construction of new farm irrigation services and business activity in Alberta continued to drive the need for additional distribution lines. FortisAlberta worked closely with the transmission service provider and the Alberta Electric System Operator to increase substation capacity, improve reliability and meet customer load growth in Devon, Fort Saskatchewan, Manyberries, Hayter, Fort Assiniboine and Hardisty.

The Company's multi-year Automated Meter Infrastructure ("AMI") Project, estimated at a total capital cost of $155 million, involves the scheduled replacement of 466,000 conventional meters at customer sites with AMI technology by the end of 2011. Approximately 260,000 electronic meters have been installed to date. AMI technology, which replaces the manual and estimated meter reading system, will help reduce operating costs and enable customers to better monitor and manage their energy consumption. By eliminating the need for manual meter readings, carbon dioxide emissions from utility vehicles will be reduced by more than 1,000 metric tonnes annually.

The Government of Alberta implemented regulation in 2009 to assist Albertans in generating electricity from renewable sources to power their homes, farms and businesses. During the year, FortisAlberta connected 60 wind and solar power customers to its distribution system, enabling them to obtain electricity when needed and receive credit from their respective retailers for renewable-source energy supplied to the province's electricity grid. FortisAlberta ensures these interconnections are safe and do not affect power quality or reliability for other customers.

A record $407 million, before customer contributions, was invested in capital projects in 2009 to maintain the system, install automated meters and meet customer growth.

For the second consecutive year, employees received the Government of Alberta's *Best Safety Performer Award*, ranking FortisAlberta in the 99.5th percentile of employers in the province. Safety initiatives helped achieve a record low Lost-Time Injury Severity Rate in 2009. Safe-work practices resulted in seven offices celebrating a minimum of nine years without a lost-time injury.

Electrical contacts with FortisAlberta distribution lines continue to be a concern. The Company participates in the *Where's the Line?* campaign, an industry and government partnership focused on public education regarding electrical safety. Employees delivered more than 100 electrical safety presentations to high-risk external companies, emergency personnel and relevant industry associations, focusing on safe-work planning, effective response to electrical incidents and the dangers of high-voltage work.

Through its Environmental Management System, which is consistent with the international ISO 14001 standard, programs have been established to improve environmental performance. More than 600 employees received job-specific environmental training in 2009.

FortisBC

FortisBC is an integrated electric utility operating in the southern interior of British Columbia, serving approximately 159,000 customers directly and indirectly. Its utility assets include approximately 7,000 kilometres of transmission and distribution power lines and four regulated hydroelectric generating plants on the Kootenay River with a combined capacity of 223 MW. The annual gross energy entitlement from the plants is approximately 1,591 gigawatt hours ("GWh"). The Company also manages 947 MW of hydroelectric generation through contract services. It generates approximately 45 per cent of its electricity requirements with the balance met through power purchase agreements. The utility met a peak demand of 714 MW in 2009. A record summer peak demand of 406 MW was met in 2009, exceeding the previous record of 387 MW reached in 2007.

Officers of FortisBC (l-r): David Bennett, VP, Regulatory Affairs, General Counsel and Corporate Secretary; Doyle Sam, VP, Engineering and Operations; John Walker, President and CEO; Michele Leeners, VP, Finance and CFO; Michael Mulcahy, VP, Customer and Corporate Services; Don Debienne, VP, Power Supply and Strategic Planning

A Customer Satisfaction Rating of 86 per cent was achieved in 2009, consistent with the rating in 2008. Results in all customer service areas were strong, despite the impact of a significant winter storm which affected more than 18,000 customers in the Kootenay area. Overcoming the challenges of severe weather conditions and road closures, employees restored service to all affected customers within 24 hours.

FortisBC invested approximately $115 million, before customer contributions, in capital projects in 2009 to meet growing energy demand and replace aging infrastructure. Construction of the $15 million Black Mountain substation and associated distribution line was completed, servicing growth to areas in northeast Kelowna. A new substation in north Kelowna, the final phase of the $17 million Ellison project, and the $7 million Naramata substation project were commissioned. Work also began on the $18 million Benvoulin substation project to meet growing customer demand in central Kelowna.

The $110 million Okanagan Transmission Reinforcement Project is the largest capital project ever undertaken by FortisBC.

Construction started on the $110 million Okanagan Transmission Reinforcement Project, the largest capital project ever undertaken by FortisBC. Upgrades to existing transmission lines and substations and the building of a new 230-kilovolt ("kV") distribution line and substation are scheduled for completion by mid-2011.

Approximately $13 million was invested in the ongoing hydroelectric generation Upgrade and Life Extension Program in 2009, which involves rebuilding 11 of the 15 hydroelectric generating units in the utility's four generating plants. Eight units have been rebuilt to date and the program is scheduled for completion in 2012. The upgrades will improve efficiency, safety and environmental stewardship and will maintain the overall reliability of the plants.

In September, FortisBC received regulatory approval for its Net Metering Program, which enables customers to offset part or all of their electricity requirements by generating electricity from renewable sources, such as wind, hydro or solar. Customers receive a billing credit for any renewable-source energy they provide to the Company's electricity grid.

A proactive consultation program continues with the public, stakeholders and First Nations in regard to capital programs, focusing on creating meaningful opportunities for open dialogue, information sharing and long-term cooperative relationships. FortisBC received the *2009 Industry Partner Award* at the British Columbia Aboriginal Tourism Awards ceremony.

Celebrating its 20th anniversary in 2009, the Company's *PowerSense Program* offers customers financial incentives and advice on energy-efficient technologies and practices. Since 1989, customers have achieved total energy savings of 360 GWh–the equivalent of the energy used by almost 28,000 homes for a full year.

Newfoundland Power operates an integrated generation, transmission and distribution system in Newfoundland. The Company serves more than 239,000 customers or 85 per cent of electricity consumers in the province. It owns and operates 30 small generating stations with an installed generating capacity of approximately 140 MW, of which 97 MW is hydroelectric generation, and has approximately 11,000 kilometres of transmission and distribution lines. Newfoundland Power met a peak demand of 1,219 MW in 2009. Approximately 92 per cent of its energy requirement is purchased from Newfoundland and Labrador Hydro ("Newfoundland Hydro").

Officers of Newfoundland Power (l-r): Jocelyn Perry, VP, Finance and CFO; Peter Alteen, VP, Regulation and Planning; Gary Smith, VP, Customer Operations and Engineering; Earl Ludlow, President and CEO

A Customer Satisfaction Rating of 90 per cent was achieved in 2009, slightly higher than the rating for the previous year. Newfoundland Power launched four new energy rebate programs for residential and commercial customers under its *takeCHARGE–Saving Energy Starts Here!* partnership with Newfoundland Hydro. Almost 2,000 customers availed of the new rebate programs, which were promoted through media, trade shows, municipal seminars and point-of-purchase information at building supply stores. The *takeCHARGE* Energy Savers Rebate Programs and similar initiatives will help customers conserve 15 GWh of energy annually by 2013–equivalent to the energy needs of 1,400 homes heated with electricity.

Almost $74 million, before customer contributions, was invested in capital projects in 2009 to upgrade and modernize the utility's electricity system. More than 30 per cent of this investment was allocated to connect a record annual addition of 5,000 new customers. A $4.5 million upgrade of transmission lines, including two transmission lines on the Bonavista Peninsula, was completed. The penstock at the Rocky Pond hydroelectric plant was replaced at a total cost of approximately $5.2 million and a $4.5 million refurbishment and upgrade of several substations across the province was completed. 2009 was a record year for the lowest number and shortest duration of power outages.

As part of its Five-Year Capital Plan, the Company is increasing the efficiency of its hydroelectric plants, which will reduce its need for energy from Newfoundland Hydro's Holyrood Generating Plant. More than $0.5 million was invested to raise the spillway and increase the amount of energy output at the Rose Blanche hydroelectric plant. Almost 1,400 streetlights across the province were replaced with energy-efficient high-pressure sodium lights, which consume 35 per cent less energy and maintain the same quality of light as traditional streetlights.

2009 was the best year on record for safety performance, with the Company reporting its lowest number of safety injuries in more than 40 years. Safety performance was driven by refocused employee commitment to safety supported by several initiatives, including the launch of a new internal safety program. A new television advertisement promoted public awareness of electrical hazards. A direct mail campaign to contractors was completed as a reminder about safety requirements when working around electrical equipment. Newfoundland Power continued to partner with Newfoundland and Labrador Crime Stoppers to prevent incidents of vandalism and convey the safety risks associated with damaged electrical equipment.

Almost $74 million, before customer contributions, was invested in capital projects in 2009 to upgrade and modernize the utility's electricity system.

An external audit of the Environmental Management System verified continued compliance with the international ISO 14001 standard and confirmed the Company's commitment to carrying out its operations in an environmentally responsible manner. 2009 marked the 12th anniversary of Newfoundland Power's *EnviroFest Program* which, to date, has entailed the planting of almost 2,000 trees to improve the environment and beautify green spaces throughout the province.

Maritime Electric

Maritime Electric, the principal electric utility on Prince Edward Island (the "Island"), serves approximately 74,000 customers or 90 per cent of electricity consumers in the province. The Company owns and operates a fully integrated system, comprised of approximately 5,300 kilometres of transmission and distribution lines, providing for the generation, transmission and distribution of electricity throughout the Island. Maritime Electric maintains on-Island generating facilities with a combined total capacity of 150 MW at Charlottetown and Borden-Carleton. The electricity system is connected to the mainland power grid via two submarine cables under the Northumberland Strait. The utility met a peak demand of 219 MW in 2009.

Officers of Maritime Electric (l-r): Steve Loggie, VP, Customer Service; John Gaudet, VP, Corporate Planning and Energy Supply; Bill Geldert, VP, Finance & Administration, CFO and Corporate Secretary; Fred O'Brien, President and CEO

Maritime Electric purchases approximately 86 per cent of the energy required to serve customers from New Brunswick Power ("NB Power"). Purchases are made through a short-term energy purchase agreement with NB Power and entitlements from NB Power's Point Lepreau Nuclear Generating Station ("Point Lepreau") and Dalhousie Generating Station through agreements that extend for the life of these stations. A refurbishment of Point Lepreau began in April 2008, which will extend its life by 25 years and provide additional stability with respect to long-term energy supply. The station is scheduled to return to service in early 2011.

The balance of the Company's energy requirements is obtained from on-Island wind-powered generation facilities and from the utility's own generating plants. Approximately 14 per cent of total energy supply was derived from wind-powered generation in 2009.

While challenged with increasing energy costs to meet the Island's energy demand, Maritime Electric achieved a Customer Satisfaction Rating of 75 per cent in 2009. To enhance customer service, the Company's website was redesigned with energy-efficient interactive and educational tools such as the *Virtual Home, Energy Calculator* and *100 Ways to Save on Your Electricity Bill*.

Approximately $30 million, before customer contributions, was invested in capital projects in 2009 to improve system reliability and customer service. Construction was completed on the 71-kilometre 138-kV transmission line and power corridor in western Prince Edward Island, which will deliver wind-powered energy to the North American grid. The $16 million project, jointly funded by the Government of Prince Edward Island and SUEZ Energy North America, will facilitate further expansion of wind-powered generation on the Island.

Maritime Electric's goal is that 30 per cent of its annual energy sales be sourced from renewable energy supply by 2013. Work continues with the Government of Prince Edward Island and PEI Energy Corporation on the development of additional generation from renewable sources. In October, Maritime Electric issued a request for proposal seeking 30 MW of energy from renewable resources. The Company is also supporting the development of an additional 100 MW from wind-powered sources that will help the province of Prince Edward Island in its efforts to capitalize on the Island's wind resource and meet its target of 500 MW of wind-powered generation on the Island by 2013.

Maritime Electric serves approximately 74,000 customers on Prince Edward Island.

In order to facilitate the export of merchant wind-generated electricity, Maritime Electric is working with the province of Prince Edward Island to secure the necessary funding for the installation of a 200-MW interconnection with the mainland via a cable in the Confederation Bridge.

Through its *Demand Side Management and Energy Conservation Program*, an energy audit was undertaken of 15 businesses with the results used to provide energy conservation information to interested parties through a series of town hall meetings. The *Winter Challenge Program* challenged residential customers to reduce their energy consumption by 10 per cent in December 2009 from December 2008. More than 4,600 customers met the challenge.

FortisOntario

FortisOntario is an integrated electric utility which owns and operates Canadian Niagara Power, Cornwall Electric and Algoma Power, serving approximately 64,000 customers mainly located in Fort Erie, Port Colborne, Cornwall, Gananoque and the District of Algoma in Ontario. Its regulated assets include approximately 3,300 kilometres of distribution and transmission lines in the Niagara and Cornwall regions and the District of Algoma, including an international interconnection between New York State and Fort Erie. FortisOntario owns a 10 per cent strategic interest in Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc., three regional electric distribution companies serving approximately 38,000 customers. The Company purchases its electricity from the Independent Electricity System Operator in Ontario, with the exception of Cornwall Electric which is supplied by Hydro-Québec. A combined peak demand of 265 MW was met in 2009.

Officers of FortisOntario (l-r): William Daley, President and CEO; Glen King, VP, Finance and CFO; Angus Orford, VP, Operations; Scott Hawkes, VP, Corporate Services, General Counsel and Corporate Secretary

In October, FortisOntario acquired Algoma Power (formerly known as Great Lakes Power Distribution Inc.), which serves approximately 12,000 customers in the District of Algoma in northern Ontario. Its assets include more than 1,800 kilometres of distribution lines in an area that covers approximately 14,200 square kilometres, which is more than double the size of the Greater Toronto Area.

A record overall Customer Satisfaction Rating of 88 per cent was achieved in 2009 compared to 84 per cent in the previous year. Customers rated the utility's reliability/safe delivery of electricity and quality of service at 94 per cent and 91 per cent, respectively. The Company continues to exceed the performance standards set by the Ontario Energy Board with respect to response times, service connections and call response statistics.

Capital investments totalled approximately $16 million, before customer contributions, in 2009, including new service connections and system rebuild projects to enhance the safety and reliability of the distribution system. In Niagara, construction was completed on a new $2.1 million substation to support load growth and replace an existing substation near the end of its useful life. Feeder upgrades were completed to increase system capacity for normal supply and emergency support, and work continued on voltage conversions. In Gananoque, construction continued on the rebuilding of the 26.4-kV feeders and replacement of distribution equipment nearing the end of its useful life. In Cornwall, capital projects focused on new customer connections, rebuilding a 3.5-kilometre rural feeder to support industrial and residential load growth and constructing a 4-kilometre feeder to supply load-transfer customers formerly supplied by Hydro One.

A record overall Customer Satisfaction Rating of 88 per cent was achieved in 2009.

The Government of Ontario has mandated all regulated electric utilities in the province to install smart meters, which track time-of-use consumption data, at customer sites by the end of 2010. During 2009, FortisOntario completed 90 per cent of smart meter installations in Fort Erie and began installations in Port Colborne. Smart meter installations in the Gananoque and Algoma territories will begin spring 2010. Time-of-use rates are anticipated to be implemented by spring 2011.

FortisOntario is implementing an integrated health, safety and environmental management system. Its utilities received Merit Certificates from the Electrical and Utilities Safety Association of Ontario in recognition of achieving zero lost-time injuries. A follow-up waste audit in 2009 verified 93 per cent of office waste was being diverted from landfill.

Belize Electricity

Belize Electricity is the primary distributor of electricity in Belize, Central America. Serving approximately 76,000 customers, the utility met a peak demand of 76 MW in 2009 from multiple sources of energy, including power purchases from Belize Electric Company Limited ("BECOL"), Comisión Federal de Electricidad ("CFE") (the Mexican state-owned power company), Belize Cogeneration Energy Limited ("BELCOGEN"), Hydro Maya Limited and Belize Aquaculture Limited, and from its own diesel-powered and gas-turbine generation. All major load centres are connected to the country's national electricity system, which is interconnected with the Mexican national electricity grid, allowing the Company to optimize its power supply options. Belize Electricity has an installed generating capacity of 34 MW and owns more than 2,900 kilometres of transmission and distribution lines. Fortis holds an approximate 70 per cent controlling ownership interest in Belize Electricity.

Despite the significant ongoing operational constraints imposed as a result of regulatory decisions received in 2008, which are being challenged in the Supreme Court of Belize, Belize Electricity earned a Customer Satisfaction Rating of approximately 82 per cent in 2009.

Officers of Belize Electricity (l-r): Rene Blanco, VP, Finance & Administration and CFO; Lynn Young, President and CEO; Curtis Eck, VP, Customer Care and Operations; Joseph Sukhnandan, VP, Engineering and Energy Supply; Juliet Estell, Manager, Executive Services and Company Secretary

Approximately $24 million, before customer contributions, was invested in capital programs in 2009. Almost 68 kilometres of distribution lines were built to meet growth in customer demand and improve the quality of service delivery. Approximately 18 kilometres of distribution lines, including a 1.6-kilometre submarine cable, were constructed to enhance reliability of service to customers, including major tourism and real estate developments, on the island of San Pedro.

Belize Electricity proceeded with the US$2.3 million Banana Belt Electrification Project to connect seven rural communities in southern Belize to the national electricity grid. Funding for this project is being provided by the European Union and the Government of Belize. Approximately 80 kilometres of distribution lines are being constructed to deliver electricity service for the first time to almost 5,000 residents. Two of the seven communities have been connected to the national electricity grid with the remainder to be connected by mid-2010.

Approximately US$2 million was invested in 2009 to build new substations and associated transmission lines to connect Belize Aquaculture Limited, BELCOGEN and BECOL's Vaca hydroelectric generating facility. These new generation facilities will collectively supply up to 48 MW of capacity to the national electricity grid, bringing total in-country generation capacity to 117 MW.

CFE cancelled its Power Purchase Agreement ("PPA") with Belize Electricity in October, citing force majeure reasons. CFE advised that the cancellation of the PPA, which was to expire in December 2010, had become necessary as a result of limited generation capacity. CFE continues to supply Belize Electricity with power when available. With in-country generation capacity well above the country's peak demand, Belize Electricity is only purchasing power from Mexico when it is more economical than in-country generation.

Approximately $24 million, before customer contributions, was invested in capital projects in 2009.

Belize Electricity continues to strengthen its Environmental Management System by ensuring it meets and exceeds all related legal requirements. Key areas of focus in 2009 were spill prevention and response. The transportation of fuel over open waters to Caye Caulker for generation purposes was made safer by using a barge specifically designed to carry petroleum products and equipped with safety features to minimize the risk of spills. Environmental training was undertaken with employees and contractors.

Employee development continues to be a priority. Hotline techniques training was completed, enabling crews to carry out maintenance on energized power lines, which helps improve service reliability. Line crews were also trained to conduct line inspections and thermoscanning surveys to quickly identify and address trouble spots on the electricity system. Under a four-year Apprenticeship Training Program, modelled after FortisAlberta's program, 30 line staff are working to become certified journeymen.

Caribbean Utilities

Caribbean Utilities generates, transmits and distributes electricity to more than 25,000 customers on Grand Cayman, Cayman Islands. The utility owns and operates approximately 555 kilometres of transmission and distribution lines and 24 kilometres of high-voltage submarine cable. Its electricity system has an installed generating capacity of approximately 153 MW. The Company met a record peak demand of 97.5 MW in 2009.

The Class A Ordinary Shares of Caribbean Utilities are listed in US funds on the Toronto Stock Exchange under the symbol CUP.U. Fortis has an approximate 59 per cent controlling ownership interest in the utility.

Caribbean Utilities is one of the most reliable and efficient utilities in the Caribbean region. The Company achieved a Customer Satisfaction Rating of 84 per cent in 2009 compared to 87 per cent in 2008. The slightly lower rating was attributable to the customer impact of increased fuel prices. Caribbean Utilities posted an Average Service Availability Index of 99.95 per cent in 2009.

Officers of Caribbean Utilities (l-r): David Watler, VP, Production; Richard Hew, President and CEO; Letitia Lawrence, VP, Finance and CFO; Douglas Murray, Corporate Secretary; Andrew Small, VP, Transmission and Distribution

Capital investments totalled approximately $45 million in 2009. Projects undertaken included completion of the building expansion and installation of a 16-MW diesel-powered generating unit and associated equipment for a total project cost of approximately US$30 million, the US$8 million expansion and upgrade to the transmission and distribution system and the US$1 million upgrade to the North Sound substation. Under a strategic alliance relationship over the past ten years with MAN Diesel SE, Caribbean Utilities has acquired five diesel-powered generating units, bringing total installed MAN Diesel SE supplied generation to approximately 69 MW.

Caribbean Utilities completed the installation of more than 200 concrete poles, weighing almost 10,000 pounds each, associated with its 69-kV transmission loop along the Frank Sound Road. The poles, which are designed to better sustain the potential impact of a hurricane, will enhance reliability of electricity service and help meet growth in energy demand.

Caribbean Utilities continues to explore energy supply options from renewable sources such as solar (photovoltaic) or wind. The *Consumer Owned Renewable Energy Program*, a joint initiative between the Company and the ERA, provides a mechanism for customers on Grand Cayman who generate their own energy from renewable sources to remain connected to the utility's transmission and distribution system. Caribbean Utilities is reviewing two proposals received in response to its expressions of interest for up to 10 MW of wind-powered generation.

Caribbean Utilities is one of the most reliable and efficient utilities in the Caribbean region.

Caribbean Utilities hosted the Caribbean Electric Utility Service Corporation ("CARILEC") CEOs conference in June. CARILEC is an association of 33 electric utilities, suppliers, manufacturers and other stakeholders operating in the electricity industry in the Caribbean. It plays a coordinating role in servicing its members' needs for training, research, information sharing and mutual aid in disaster recovery.

Caribbean Utilities continues to demonstrate its environmental commitment through its ISO 14001:2004 registered Environmental Management System associated with its generation operations. A *Scrap Metal Recycling Program* was implemented to centrally collect scrap metal and ship overseas for recycling. Under its *Energy Smart Program*, which promotes energy conservation, the Company has been conducting complimentary energy smart audits for customers for seven years.

Fortis Turks and Caicos

Fortis Turks and Caicos is a fully integrated electric utility providing for the generation, transmission and distribution of electricity on Providenciales, North Caicos, Middle Caicos and South Caicos and the supply of electricity on Dellis Cay in the Turks and Caicos Islands. Fortis Turks and Caicos serves more than 9,000 customers or 85 per cent of electricity consumers in the Turks and Caicos Islands. Its regulated assets include 235 kilometres of transmission and distribution lines. The utility has a combined diesel-powered generating capacity of 54 MW and met a combined record peak demand of 29.6 MW in 2009.

An overall Customer Satisfaction Rating of 95 per cent was achieved in 2009 compared to 79 per cent in 2008. The improved rating was attributable to the Company's performance in restoring service following a tropical storm and Category 4 hurricane in September 2008, enhanced system reliability and the introduction of new customer services, such as the launch of the utility's website, electronic billing (eBills) and Internet bill payment options.

Officers of Fortis Turks and Caicos (l-r): Ruth Gardiner-Forbes, VP, Finance and CFO; Brian Walsh, VP, Operations; Eddinton Powell, President and CEO; Allan Robinson, VP, Customer and Corporate Services; Ernest Jackson, VP, Production and Engineering

Capital investments totalled approximately $23 million, before customer contributions, in 2009. Construction of the US$2 million central warehouse and US$0.9 million vehicle maintenance centre was completed which, together with the re-engineering of the utility's purchase order and inventory systems, have significantly improved material management procedures. Several information technology ("IT") infrastructure projects were completed to improve internal communications and reporting capabilities, including the new US$0.4 million IT Disaster Recovery Centre, the installation of an exchange server, completion of a network upgrade and the installation of fibre-optic links between corporate offices, the central warehouse, the IT Disaster Recovery Centre and the generation plant building.

Two Caterpillar 3612 series units were commissioned in May at a total cost of US$8.3 million, increasing the utility's installed generating capacity by 6.6 MW. A purchase agreement was signed with Wärtsilä Finland OY in June for two diesel-powered generating units with a combined capacity of approximately 18 MW. The units are scheduled for delivery mid-2010 and early 2011.

The US$0.5 million Bellamy Re-engineering Project was launched in January, an initiative to streamline internal operating procedures and upgrade the utility's financial reporting system to improve overall operational effectiveness, and enable the implementation of a fixed-asset management system.

Significant progress was made in the development of the Company's Environmental Management System in 2009. The US$0.6 million refurbishment and noise-attenuation work to the Engine Room South Building was completed, drastically reducing noise levels at the plant. All exhaust stacks were increased in height to achieve optimum plume dispersion as recommended in the Company's environmental audit. Construction began on the first phase of the ground water management systems, which will control heavy rainfall runoff from buildings.

Employee development is a major priority for Fortis Turks and Caicos. During the year, the Company offered IT, credit-control and line-staff apprenticeship training, and provided opportunities for employees to gain exposure to similar operations across the Fortis Group. With the introduction of its scholarship program, the Company granted three engineering scholarships and one accounting scholarship.

An overall Customer Satisfaction Rating of 95 per cent was achieved in 2009.

Fortis Generation includes the operations of non-regulated generating assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State with a combined generating capacity of 139 MW, 134 MW of which is hydroelectric generation.

BECOL owns and operates the 25-MW Mollejon, the 7-MW Chalillo and, as of March 2010, the 19-MW Vaca hydroelectric generating facilities located on the Macal River, the largest such facilities in Belize, Central America. Energy production was higher than the projected average at 180 GWh in 2009 compared to 192 GWh in 2008, when annual energy production hit a record high due to above-average rainfall. The Belize Meteorological Office confirmed that the flood-control features of the Chalillo facility significantly reduced the impact on downstream communities of widespread flooding related to heavy rainfall in July.

The US$53 million Vaca facility will be commissioned in March 2010. The run-of-river hydroelectric facility, which is situated approximately five kilometres downstream from Mollejon, is the final phase of the three-phase hydroelectric development plan for the Macal River. BECOL sells its entire output to Belize Electricity under 50-year power purchase agreements.

Fortis Generation has a combined generating capacity of 139 MW, 134 MW of which is hydroelectric generation.

In Ontario, non-regulated operations include six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW and a 5-MW gas-powered cogeneration plant in Cornwall. The electricity produced from these facilities is sold in Ontario at market prices, with the exception of the cogeneration plant in Cornwall. The 75 MW of water-right entitlement associated with the Rankine hydroelectric generating station at Niagara Falls expired in April at the end of a 100-year term.

The Exploits River Hydro Partnership ("Exploits Partnership") is owned 51 per cent by Fortis Generation and 49 per cent by AbitibiBowater Inc. ("Abitibi"). The Exploits Partnership was established in 2001 and commenced operations in 2003 following the development of additional capacity at Abitibi's two hydroelectric generating plants in central Newfoundland. In December 2008, the Government of Newfoundland and Labrador passed legislation expropriating most of Abitibi's assets in Newfoundland, including those assets associated with the generation of electricity, some of which included the capital assets of the Exploits Partnership. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi in the province.

The US$53 million 19-MW Vaca hydroelectric generating facility on the Macal River in Belize will be commissioned in March 2010.

In British Columbia, the non-regulated generating asset is the 16-MW run-of-river Walden hydroelectric generating plant near Lillooet, which was acquired in May 2004 as part of the assets of FortisBC. The plant sells its entire output to BC Hydro under a long-term contract.

In Upper New York State, the non-regulated generating assets are four hydroelectric generating stations located in Moose River, Philadelphia, Dolgeville and Diana. The plants have a combined capacity of approximately 23 MW. The average annual 85 GWh of energy output of these modern facilities is sold at the wholesale level through a number of renewable contracts.

Fortis Properties

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

The Hospitality Division was significantly challenged in 2009 by the global economic downturn. Revenue per available room ("RevPAR") decreased by 4.8 per cent to $76.55 from the previous year, primarily as a result of decreased occupancy. An aggressive cost-management strategy was implemented to mitigate revenue pressures resulting from the economic downturn. National RevPAR declined 12.3 per cent for 2009 compared to the previous year.

Fortis Properties acquired the 214-room Holiday Inn Select Windsor in Ontario for $7 million in April. The hotel offers standard, suite and executive rooms and has more than 14,000 square feet of meeting and banquet space. A four-year $4.1 million capital investment began in 2009 to complete interior renovations, including the installation of a fire-sprinkler system, and exterior upgrades.

Officers of Fortis Properties: Nora Duke, President and CEO; Jamie Roberts, VP, Finance and CFO; Terry Chaffey, VP, Real Estate

Approximately $3.2 million was invested in lobby and room renovations at the Sheraton Hotel Newfoundland. The hotel's extensive capital improvement plan will continue through to 2011 with upgrades to guest rooms, food and beverage outlets and meeting space.

The 70-room expansion of the Holiday Inn Express Kelowna opened in February 2010. The new tower includes executive rooms, business and family suites, two indoor waterslides and approximately 4,500 square feet of meeting space.

The Real Estate Division continued to exhibit stable performance, supported by a focus on quality customer service and long-term leases with quality tenants. The year-end occupancy rate was 96.2 per cent, outpacing the national rate of 90.2 per cent. Most of the Company's major real estate holdings have been operating at full occupancy. Approximately $2.9 million in capital investment focused on asset enhancement and maintenance and leasehold improvements.

Technology solutions were initiated to improve productivity and provide optimal customer service. Phase I of a new human resource/payroll system was completed, providing improved operational efficiencies and supporting future organizational growth.

Fortis Properties was bestowed three awards by the Building Owners and Managers Association, Newfoundland and Labrador Chapter: the *Pinnacle Award* for customer service, the *Team Excellence Award – Property Team of the Year* and the *Office Building of the Year* for Cabot Place.

All Fortis Properties hotels have been certified under the *Hotel Association of Canada*'s *GreenKey Eco-Rating Program*, which recognizes hotels, motels and resorts that are committed to improving their fiscal and environmental performance.

The 70-room expansion of the Holiday Inn Express Kelowna opened in February 2010.

Fortis Properties and its employees recently received two hospitality awards. Delta Brunswick was recognized for its community involvement and leadership with the *Hotel Association of Canada*'s *Humanitarian Award*. The award is given to a property that has demonstrated dedication and responsiveness to community needs through volunteerism, donations and community leadership. The Company also received the *President's Award for North America* from Starwood Hotels and Resorts Worldwide, Inc., owners of the Sheraton and Four Points by Sheraton brands. The award is given to hotel owners that possess strong leadership and an ongoing commitment to a shared vision of community success in a manner consistent with the Starwood brand.

Our Community

Fortis employees are committed to helping improve the quality of life in the communities where we work and live.

We've got spirit! Team spirit. Community spirit. Employee spirit. Fortis employees show their caring spirit by opening up their hearts and rolling up their sleeves to help improve the quality of life in the communities where we work and live. The Fortis Group contributed more than $3 million in financial and in-kind donations in 2009 to community initiatives that are helping to make our world a better, brighter place.

Here are a few of the partnerships we were proud to be involved with during the year:

Terasen joined forces with the *Tynehead Hatchery*, operated by the non-profit volunteer Serpentine Enhancement Society, in Surrey, British Columbia to celebrate Earth Day. Volunteers released Chinook salmon fry and completed gardening and painting tasks.

FortisAlberta employees generated significant donations for eight local United Way chapters. The Company's *2009 United for a Cause* campaign raised $181,000 to improve the lives of individuals and families across Alberta.

FortisBC employees and families pitched in to help make the *Great Canadian Shoreline Cleanup* a success, collecting some 2,500 kilograms of garbage from the shoreline of the Columbia River in downtown Trail, British Columbia.

Heart and Stroke Foundation's Big Bike Ride.

Newfoundland Power contributed approximately $165,000 to *The Power of Life Project*. Five chemotherapy chairs were donated to the Cancer Centre Western Region and a blanket warmer was provided to the Burin Cancer Centre.

2009 Canada Games

Maritime Electric was one of the five *Friends of the 2009 Canada Games Sponsors*, which contributed a combined $250,000 to the national multi-sport and cultural event held on Prince Edward Island.

FortisOntario contributed $15,000 towards energy-efficient lighting for the Town of Fort Erie's new skate park and $10,000 towards the Town of Gananoque's *King Street Lighting Beautification Project*.

Belize Electricity was a major sponsor of the *4th Annual Belize Band Fest*, which provides an opportunity for young people to showcase their musical talent.

Caribbean Utilities hosted 36 high school and college students as part of the *2009 Summer Work Experience Program*.

Fortis Turks and Caicos was the main sponsor of the newly opened *Bright Community Park*, the principal public beach recreation and environmental park on Providenciales.

Fortis Properties helped raise $67,000 for the *Children's Wish Foundation of Canada* through a dinner and silent auction hosted by the Sheraton Hotel Newfoundland.

Management Discussion and Analysis

Dated March 2, 2010

The following Management Discussion and Analysis ("MD&A") should be read in conjunction with the 2009 Consolidated Financial Statements and Notes to the 2009 Consolidated Financial Statements included in the Fortis Inc. ("Fortis" or the "Corporation") 2009 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.

Barry Perry, VP, Finance and CFO, Fortis Inc.

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 increase in average annual energy production from the Macal River in Belize by the Vaca hydroelectric generating facility; the expected timing of regulatory decisions; negligible electricity sales growth is expected at the Corporation's regulated utilities in the Caribbean for 2010; organic revenue growth at Fortis Properties' Hospitality Division is expected to continue to be challenged in 2010; consolidated forecasted gross capital expenditures for 2010 and in total over the five-year period from 2010 through 2014; the nature, timing and amount of certain capital projects and their expected costs and time to complete; the expected impacts on Fortis of the economic downturn; the expectation of no significant decrease in annual consolidated operating cash flows in 2010 as a result of any continuation of the economic downturn; the expectation that the subsidiaries will be able to source the cash required to fund their 2010 capital expenditure programs; the expectation that the Corporation and its utilities will continue to have reasonable access to capital in the near to medium terms; expected consolidated long-term debt maturities and repayments in 2010 and on average annually over the next five years; no material increase in consolidated interest expense and/or fees associated with renewed and extended credit facilities is expected in 2010; no material adverse credit rating actions are expected in the near term; the expected impact of a change in the US dollar-to-Canadian dollar foreign exchange rate on basic earnings per common share in 2010; the estimated impact a decrease in revenue at Fortis Properties' Hospitality Division would have on basic earnings per common share; the expectation that counterparties to the Terasen Gas companies' gas derivative contracts will continue to meet their obligations; and the expectation of an increase in consolidated defined benefit net pension cost for 2010. The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major event; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no significant decline in capital spending in 2010; no severe and prolonged downturn in economic conditions; sufficient liquidity and capital resources; the continuation of regulator-approved mechanisms to flow through the commodity cost of natural gas and energy supply costs in customer rates; the continued ability to hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas commodity prices; no significant variability in interest rates; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas supply; the continued ability to fund defined benefit pension plans; the absence of significant changes in government energy plans and environmental laws that may materially affect the operations and cash flows of the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; no material decrease in market energy sales prices; maintenance of information technology infrastructure; favourable relations with First Nations; favourable labour relations; and sufficient human resources to deliver service and execute the capital program. The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory risk; operating and maintenance risks; economic conditions; capital resources and liquidity risk; weather and seasonality; commodity price risk; derivative financial instruments and hedging; interest rate risk; counterparty risk; competitiveness of natural gas; natural gas supply; defined benefit pension *plan performance and funding requirements; risks related to the development of the Terasen Gas (Vancouver Island) Inc. franchise; the Government of British Columbia's Energy Plan; environmental risks; insurance coverage risk; loss of licences and permits; loss of service area; market energy sales prices; changes in the current assumptions and expectations associated with the transition to International Financial Reporting Standards; changes in tax legislation; information technology infrastructure; an ultimate resolution of the expropriation of the assets of the Exploits River Hydro 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 this MD&A for the year ended December 31, 2009.*

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

Corporate Overview and Strategy

Fortis is the largest investor-owned distribution utility in Canada, serving approximately 2,100,000 gas and electricity customers. Its regulated holdings include electric utilities in five Canadian provinces and three Caribbean countries and a natural gas utility in British Columbia. Fortis owns 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. In 2009, the Corporation's electricity distribution systems met a combined peak electricity demand of 5,986 megawatts ("MW") and its gas distribution systems met a peak day demand of 1,234 terajoules ("TJ").

The vision of Fortis is to be the world leader in those segments of the regulated utility industry in which it operates and the leading service provider within its service areas. Fortis has adopted a strategy of profitable growth with earnings per common share as the primary measure of performance. The Corporation's first priority is to pursue organic growth opportunities in existing operations. Additionally, Fortis pursues profitable growth through acquisitions.

The key goals of the Corporation's regulated utilities are to operate sound gas and electricity distribution systems, deliver gas and electricity safely and reliably to customers at the lowest reasonable cost and conduct business in an environmentally responsible manner. The Corporation's main business, utility operations, is highly regulated. It is segmented by franchise area and, depending on regulatory requirements, by the nature of the assets. The operating segments of the Corporation are: (i) Regulated Gas Utilities – Canadian; (ii) Regulated Electric Utilities – Canadian; (iii) Regulated Electric Utilities – Caribbean; (iv) Non-Regulated – Fortis Generation; (v) Non-Regulated – Fortis Properties; and (vi) Corporate and Other. The earnings of the Corporation's regulated utilities are primarily determined under cost of service and rate of return methodologies. Earnings of the Canadian regulated utilities are generally exposed to changes in interest rates, which factor into customer rate-setting mechanisms.

Fortis holds investments in non-regulated generation, and commercial office and retail space and hotels, which are treated as two separate segments. The Corporation's non-regulated generation assets operate in three countries and have a combined generating capacity of 139 MW, mainly hydroelectric. Except for non-regulated hydroelectric generation operations in Belize and British Columbia, the Corporation's non-regulated generation operations are owned and/or managed by Fortis Properties to ensure standard operating practices, enable leveraging of expertise across the various jurisdictions and allow the pursuit of non-regulated hydroelectric projects. The Corporation's investments in non-regulated assets provide financial, tax and regulatory flexibility and enhance shareholder return.

The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the Corporation's long-term objectives. Each reporting segment operates as an autonomous unit, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

The following summary describes the Corporation's interests in regulated gas and electric utilities in Canada and the Caribbean by utility:

Regulated Gas Utilities – Canadian

Terasen Gas Companies: Includes Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGWI").

TGI is the largest distributor of natural gas in British Columbia, serving approximately 839,000 residential, commercial and industrial customers in a service area that extends from Vancouver to the Fraser Valley and the interior of British Columbia.

TGVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island, and the distribution system on Vancouver Island and along the Sunshine Coast of British Columbia, serving approximately 98,000 residential, commercial and industrial customers.

In addition to providing transmission and distribution ("T&D") services to customers, TGI and TGVI also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through TGI's Southern Crossing Pipeline, from Alberta.

TGWI owns and operates the newly converted natural gas distribution system in the Resort Municipality of Whistler ("Whistler"), British Columbia, which provides service to approximately 2,600 residential and commercial customers.

Regulated Electric Utilities – Canadian

a. *FortisAlberta:* FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving approximately 480,000 customers.

b. *FortisBC:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia, serving approximately 159,000 customers directly and indirectly. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 223 MW. Included with the FortisBC component of the Regulated Electric Utilities – Canadian segment are the operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Cominco Metals Ltd., the 149-MW Brilliant hydroelectric plant and 120-MW Brilliant expansion plant, both owned by Columbia Power Corporation and the Columbia Basin Trust ("CPC/CBT"), the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT and the distribution system owned by the City of Kelowna.

c. *Newfoundland Power:* Newfoundland Power is the principal distributor of electricity in Newfoundland, serving more than 239,000 customers. Newfoundland Power has an installed generating capacity of 140 MW, of which 97 MW is hydroelectric generation.

d. *Other Canadian:* Includes Maritime Electric and FortisOntario. Maritime Electric is the principal distributor of electricity on Prince Edward Island, serving approximately 74,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to approximately 64,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations include Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and, as of October 2009, Algoma Power Inc. ("Algoma Power"). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc. ("Port Colborne Hydro"), which has been leased from the City of Port Colborne under a ten-year lease agreement that expires in April 2012. FortisOntario also owns a 10 per cent interest in each of Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc. ("Grimsby Power"), three regional electric distribution companies serving approximately 38,000 customers.

Regulated Electric Utilities – Caribbean

a. *Belize Electricity:* Belize Electricity is the principal distributor of electricity in Belize, Central America, serving approximately 76,000 customers. The Company has an installed generating capacity of 34 MW. Fortis holds an approximate 70 per cent controlling ownership interest in Belize Electricity.

b. *Caribbean Utilities:* Caribbean Utilities is the sole provider of electricity on Grand Cayman, Cayman Islands, serving more than 25,000 customers. The Company has an installed generating capacity of 153 MW. Fortis holds an approximate 59 per cent controlling ownership interest in Caribbean Utilities. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U). Previously, Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, its financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. In 2008, Caribbean Utilities changed its fiscal year end to December 31, which has eliminated the previous two-month lag in consolidating its financial results.

c. *Fortis Turks and Caicos:* Includes P.P.C. Limited and Atlantic Equipment & Power (Turks and Caicos) Ltd. Fortis Turks and Caicos is the principal distributor of electricity in the Turks and Caicos Islands, serving more than 9,000 customers. The Company has a combined diesel-powered generating capacity of 54 MW.

Non-Regulated – Fortis Generation

The following summary describes the Corporation's non-regulated generation assets by location:

a. *Belize:* Operations consist of the 25-MW Mollejon, the 7-MW Chalillo and, as of March 2010, the 19-MW Vaca hydroelectric generating facilities in Belize. All of the output of these facilities is sold to Belize Electricity under 50-year power purchase agreements expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirect wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the Government of Belize.

b. *Ontario:* Includes six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW and a 5-MW gas-powered cogeneration plant in Cornwall. The 75 MW of water-right entitlement associated with the Rankine hydroelectric generating facility at Niagara Falls expired on April 30, 2009, at the end of a 100-year term.

c. *Central Newfoundland:* Through the Exploits River Hydro Partnership (the "Exploits Partnership"), a partnership between the Corporation, through its wholly owned subsidiary Fortis Properties, and AbitibiBowater Inc. ("Abitibi"), 36 MW of additional capacity was developed and installed at two of Abitibi's hydroelectric generating plants in central Newfoundland. Fortis Properties holds directly a 51 per cent interest in the Exploits Partnership and Abitibi holds the remaining 49 per cent interest. The Exploits Partnership sells its output to Newfoundland and Labrador Hydro ("Newfoundland Hydro") under a 30-year power purchase agreement expiring in 2033. Effective February 12, 2009, Fortis discontinued the consolidation method of accounting for its investment in the Exploits Partnership. For a further discussion of the Exploits Partnership, refer to the "Critical Accounting Estimates – Contingencies" section of this MD&A.

d. *British Columbia:* Includes the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia. The plant sells its entire output to BC Hydro under a long-term contract expiring in 2013.

e. *Upper New York State:* Includes the operations of four hydroelectric generating stations in Upper New York State, with a combined capacity of approximately 23 MW, operating under licences from the U.S. Federal Energy Regulatory Commission. Hydroelectric operations in Upper New York State are conducted through the Corporation's indirect wholly owned subsidiary FortisUS Energy Corporation ("FortisUS Energy").

Non-Regulated – Fortis Properties

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

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment. This segment includes finance charges, including interest on debt incurred directly by Fortis and Terasen Inc. ("Terasen") and dividends on preference shares classified as long-term liabilities; dividends on preference shares classified as equity; other corporate expenses, including Fortis and Terasen corporate operating costs, net of recoveries from subsidiaries; interest and miscellaneous revenue; and corporate income taxes.

Also included in the Corporate and Other segment are the financial results of CustomerWorks Limited Partnership ("CWLP"). CWLP is a non-regulated shared-services business in which Terasen holds a 30 per cent interest. CWLP operates in partnership with Enbridge Inc. and provides customer service contact, meter reading, billing, credit, support and collection services to the Terasen Gas companies and several smaller third parties. CWLP's financial results are recorded using the proportionate consolidation method of accounting. The financial results of Terasen Energy Services Inc. ("TES") are also reported in the Corporate and Other segment. TES is a non-regulated wholly owned subsidiary of Terasen that provides alternative energy solutions.

Financial Highlights

For the Years Ended December 31	2009	2008	Variance
Net Earnings Applicable to Common Shares *($ millions)*	**262**	245	17
Basic Earnings per Common Share *($)*	**1.54**	1.56	(0.02)
Diluted Earnings per Common Share *($)*	**1.51**	1.52	(0.01)
Weighted Average Number of Common Shares Outstanding *(millions)*	**170.2**	157.4	12.8
Revenue *($ millions)*	**3,637**	3,903	(266)
Dividends Paid per Common Share *($)*	**1.04**	1.00	0.04
Rate of Return on Average Book Common Shareholders' Equity *(%)*	**8.4**	8.7	(0.3)
Total Assets *($ millions)*	**12,160**	11,166	994
Cash Flow from Operating Activities *($ millions)*	**637**	661	(24)

Acquisitions: In October 2009, FortisOntario acquired Great Lakes Power Distribution Inc., subsequently renamed Algoma Power, for an aggregate purchase price of $75 million. Algoma Power is a regulated electric distribution utility serving approximately 12,000 customers in the District of Algoma in northern Ontario.

In June 2009, FortisOntario acquired a 10 per cent interest in Grimsby Power for approximately $1 million. Grimsby Power is a regulated electric distribution utility serving approximately 10,000 customers in a service territory in close proximity to FortisOntario's operations in Fort Erie.

In April 2009, Fortis Properties acquired the 214-room Holiday Inn Select Windsor in Ontario for approximately $7 million.

In November 2008, Fortis Properties acquired the Sheraton Hotel Newfoundland for approximately $22 million, increasing hospitality operations by 301 rooms and 16,000 square feet of convention meeting space.

Key Trends and Risks: The acquisition of Terasen in May 2007, which almost doubled the size of the Corporation's assets, provides Fortis with a platform to acquire larger-sized regulated utilities in Canada and the United States. The primary focus will likely be investor-owned US-based utilities due to the limited number of opportunities to acquire investor-owned regulated gas and electric utility assets in Canada.

Persistently low long-term interest rates in Canada have negatively affected the formula-based allowed rate of return on common shareholders' equity ("ROE") at each of the Corporation's four largest regulated utilities. However, several regulators in Canada have reviewed the cost of capital of utilities they regulate and have set allowed ROEs for 2010 at levels higher than those that would have been determined under the previous ROE automatic adjustment formulas. The chart below highlights the trend in the allowed ROEs at each of the Corporation's four largest regulated utilities.

Approved Regulator-Allowed ROEs

(%)	2006	2007	2008	2009	2010
TGI	8.80	8.37	8.62	8.47/9.50(1)	9.50
FortisAlberta	8.93	8.51	8.75	9.00(2)	9.00(2)
FortisBC	9.20	8.77	9.02	8.87	9.90
Newfoundland Power	9.24	8.60	8.95	8.95	9.00

(1) Set at 9.50 per cent, effective July 1, 2009

(2) Set for 2009, 2010 and, on an interim basis, 2011

The impact on the Corporation's consolidated earnings of lower allowed ROEs in recent years has been mitigated by earnings derived from increased rate bases and energy sales and the realization of operating cost efficiencies.

A large proportion of the businesses of Fortis serve the economies of western Canada, which have been growing faster than those of other regions of Canada. As at December 31, 2009, regulated utility assets comprised 93 per cent of total assets (December 31, 2008 – 92 per cent) and regulated utility assets in western Canada comprised 75 per cent of total regulatory assets (December 31, 2008 – 74 per cent). Organic earnings' growth from the Corporation's regulated utilities in Canada, therefore, is expected to be primarily driven by rate base growth at FortisAlberta, FortisBC and the Terasen Gas companies. The Corporation's other Canadian regulated electric utilities, Newfoundland Power, Maritime Electric and FortisOntario, are expected to generate slower earnings' growth.

Regulated assets in the Caribbean region, as a percentage of the Corporation's total regulated assets, were 8 per cent as at December 31, 2009 (December 31, 2008 – 10 per cent). Generally, the regulated rate of return on rate base assets ("ROA") in the Caribbean is higher than that in Canada. The higher return is correlated with increased operating risks associated with local economic and political factors and weather conditions. However, the allowed ROAs at Caribbean Utilities and Belize Electricity were lowered in 2008 due to the negotiation of new licences at Caribbean Utilities and the impact of a regulatory rate decision at Belize Electricity. Economic growth had been strong in the Corporation's service territories in the Caribbean; however, the economic downturn unfavourably impacted sales growth in 2009 and is expected to have a similar impact in 2010. Additionally, the Corporation's operations in the Caribbean are exposed to hurricane risk. Fortis uses external insurance to help mitigate the impact on its operations of potential damage and related business interruption associated with hurricanes.

The key business risk to Fortis is regulatory risk. Except for the Terasen Gas companies and FortisBC, which have the same regulator, the Corporation's other utilities are regulated by different regulatory authorities. Relationships with the regulatory authorities are managed at the local utility level and such relationships have generally been positive. However, the relationship of Belize Electricity with its regulator became tenuous in 2008 when the regulator issued a decision disallowing previously incurred fuel and purchased power costs and lowering the regulated ROA. The decision has and continues to negatively impacted Belize Electricity's financial health. Although the receipt of an adverse regulatory decision may materially affect the ability of any utility to recover the cost of providing its services and achieving a reasonable rate of return, the impact on the Corporation as a whole is lessened due to the geographic and regulatory diversity of its operations. The total assets of Belize Electricity comprise approximately 2 per cent of the Corporation's total assets.

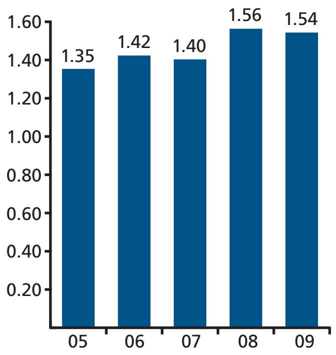
In Canada, regulator-approved negotiated settlement agreements were reached at the Terasen Gas companies for 2010 and 2011 customer gas rates and at FortisBC for 2010 customer electricity rates. Achieving regulator-approved negotiated settlement agreements eliminates the cost of public hearing processes.

The Corporation's regulated gas and electric utilities require ongoing access to long-term capital to fund investments in infrastructure necessary to provide service to customers. Long-term capital required to carry out the subsidiary capital expenditure programs is mostly obtained at the regulated utility level. The subsidiaries issue debt mostly at terms ranging between 10 years and 30 years. As at December 31, 2009, approximately 81 per cent of the Corporation's consolidated long-term debt and capital lease obligations had maturities beyond five years. To help ensure uninterrupted access to capital and sufficient liquidity to fund capital programs and working capital requirements, the Corporation and its subsidiaries have approximately $2.2 billion in credit facilities of which approximately $1.4 billion was unused as at December 31, 2009. With strong credit ratings and conservative capital structures, the Corporation and its utilities expect to continue to have reasonable access to long-term capital in 2010.

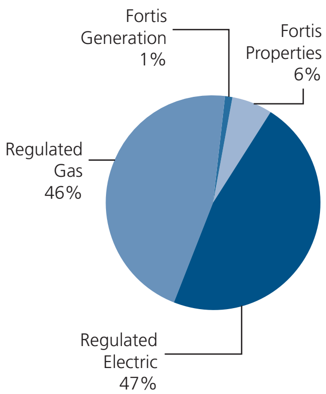
Common share dividend payments increased to $1.04 per share in 2009. Effective for the first quarter of 2010, a 7.7 per cent increase in the quarterly common share dividend to 28 cents from 26 cents translates into an annualized dividend of $1.12 and extends the Corporation's record of annual common share dividend increases to 37 consecutive years, the longest record of any public corporation in Canada.

For a complete discussion of the Corporation's business risks, including regulatory risk and the impact on the Corporation and its subsidiaries of recent economic conditions, refer to the "Regulatory Highlights" and "Business Risk Management" sections of this MD&A.

Basic Earnings per Common Share *($)*

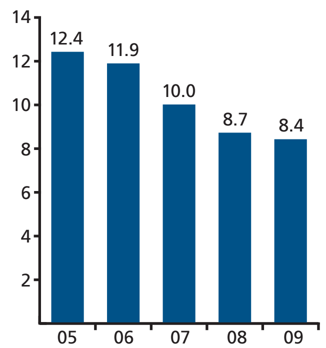


Revenue[(1)]
(year ended December 31, 2009)



[(1)] Excludes Corporate and Other

Rate of Return on Average Book Common Shareholders' Equity *(%)*



Net Earnings Applicable to Common Shares and Earnings per Common Share: Fortis achieved net earnings applicable to common shares of $262 million in 2009, up $17 million from earnings of $245 million in 2008. Earnings in 2008 were enhanced by a one-time $7.5 million tax reduction at Terasen and were reduced by one-time charges of approximately $15 million pertaining to Belize Electricity and FortisOntario. Earnings in 2009 were favourably impacted by a one-time $3 million adjustment to future income taxes related to prior periods at FortisOntario and were reduced by a one-time $5 million after-tax provision for additional costs related to the conversion of Whistler customer appliances from propane to natural gas. Excluding the above items, earnings were higher year over year mainly due to the impact of an increase in the allowed ROEs for 2009 at FortisAlberta and TGI and an increase in the deemed equity component of the total capital structure at FortisAlberta, combined with rate base growth mainly at the electric utilities in western Canada. Growth in earnings was partially offset by lower contribution from non-regulated generation operations in Ontario due to the expiration of the Rankine water rights in April 2009, and ongoing regulatory challenges at Belize Electricity.

Basic earnings per common share were $1.54 in 2009 compared to $1.56 in 2008. Basic earnings per common share in 2009 were diluted by the 11.7 million common share equity offering in December 2008, the net proceeds of which were primarily used to repay maturing long-term debt.

Revenue: Revenue was approximately $3.6 billion in 2009 compared to approximately $3.9 billion in 2008. The decrease was driven by the flow through to customers at the Terasen Gas companies and Caribbean Utilities of lower natural gas commodity and energy supply costs, respectively, combined with the loss of revenue from non-regulated generation operations in Ontario due to the expiration of the Rankine water rights in April 2009. The decrease was partially offset by the impact of basic customer rate increases, and customer growth mainly in Canada, in addition to the favourable impact of foreign exchange associated with translation of foreign currency-denominated revenue.

Rate of Return on Average Book Common Shareholders' Equity: The rate of return on average book common shareholders' equity was 8.4 per cent in 2009 compared to 8.7 per cent in 2008. The decline related to higher average book common shareholders' equity largely associated with the 11.7 million common share equity offering in December 2008.

Cash Flow from Operating Activities: Cash flow from operating activities, after working capital adjustments, was $637 million in 2009 compared to $661 million in the previous year. The decrease was mainly due to the timing of the declaration of common share dividends, the timing and an increase in the amount of corporate income taxes paid at Newfoundland Power and unfavourable working capital changes at the Terasen Gas companies reflecting differences in the commodity cost of natural gas and the cost of natural gas charged to customers year over year. The decrease was partially offset by favourable changes in the Alberta Electric System Operator ("AESO") charges deferral account at FortisAlberta.

Dividends: Dividends paid per common share increased to $1.04 in 2009, up 4.0 per cent from $1.00 in 2008. Fortis increased its quarterly common share dividend 7.7 per cent, to 28 cents from 26 cents, commencing with the first quarter dividend paid on March 1, 2010. The Corporation's dividend payout ratio was 67.5 per cent in 2009 compared to 64.1 per cent in 2008.

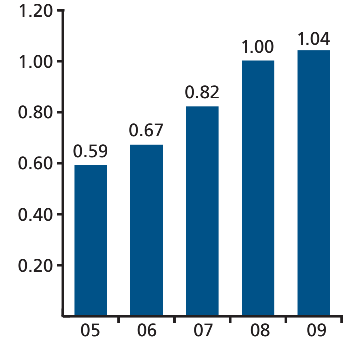
In December 2008, the Corporation's Amended and Restated Dividend Reinvestment and Share Purchase Plan (the "Dividend Reinvestment and Share Purchase Plan") provided a 2 per cent discount on the purchase of common shares issued from treasury, with reinvested dividends, effective March 1, 2009. The Corporation received $29 million from dividend reinvestments during 2009.

Asset Growth: Total assets increased almost 9 per cent to approximately $12.2 billion at the end of 2009 compared to approximately $11.2 billion at the end of 2008. The increase reflected the Corporation's continued investment in energy systems, driven by the capital expenditure programs at FortisAlberta, FortisBC and the Terasen Gas companies, and an increase in regulatory assets driven by the adoption of the amended accounting standard pertaining to income taxes. The increase was partially offset by the unfavourable impact of foreign exchange associated with translation of foreign currency-denominated assets. For a further discussion of the nature of the impact of the adoption of the amended accounting standard for income taxes, refer to the "Changes in Accounting Standards" section of this MD&A.

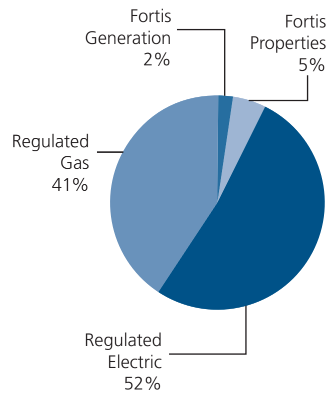
2009 Capital Expenditures: During 2009, consolidated capital expenditures, before customer contributions ("gross capital expenditures"), were $1,024 million, up $89 million from $935 million in 2008. Total capital investment at the regulated utilities in western Canada in 2009 was approximately $768 million, representing approximately 75 per cent of total gross capital expenditures. Much of the capital investment was driven by customer growth and the need to enhance the reliability of energy systems. The larger capital projects during 2009 included the continued construction of the liquefied natural gas ("LNG") storage facility at TGVI, the installation of automated meter technology at FortisAlberta, the Okanagan Transmission Reinforcement Project at FortisBC and BECOL's 19-MW Vaca hydroelectric generating facility in Belize.

Financings: During 2009, Fortis and its regulated utilities raised more than $700 million in long-term debt. In July 2009, Fortis issued $200 million 30-year 6.51% unsecured debentures. The net proceeds from the debenture offering were used to repay in full the indebtedness outstanding under the Corporation's credit facility and for general corporate purposes. At the subsidiary level, TGI issued $100 million 30-year 6.55% unsecured debentures in February; FortisAlberta issued $100 million 30-year 7.06% unsecured debentures in February and $125 million 30-year 5.37% unsecured debentures in October; Newfoundland Power issued $65 million 30-year 6.606% first mortgage sinking fund bonds in May; FortisBC issued $105 million 30-year 6.10% unsecured debentures in June; and Caribbean Utilities issued US$30 million and US$10 million in May and July, respectively, 15-year 7.50% unsecured notes. Proceeds from the long-term debt issues at the regulated utilities were mainly used to repay indebtedness under credit facilities incurred primarily in support of capital spending, to repay $110 million of maturing debt at TGI and FortisBC and to finance capital expenditures.

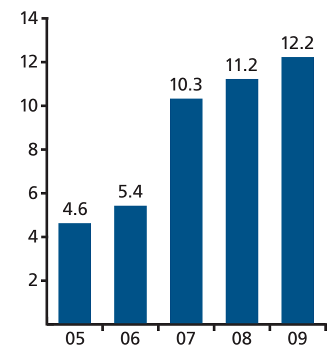
Dividends Paid per Common Share *($)*



Total Assets
(as at December 31, 2009)



Total Assets *($ billions)*
(as at December 31)



Segmented Results of Operations

The segmented results of the Corporation are outlined below.

Segmented Net Earnings

Years Ended December 31 *($ millions)*	**2009**	2008	Variance
Regulated Gas Utilities – Canadian			
Terasen Gas Companies	**117**	118	(1)
Regulated Electric Utilities – Canadian			
FortisAlberta	**60**	46	14
FortisBC	**37**	34	3
Newfoundland Power	**32**	32	–
Other Canadian[(1)]	**20**	14	6
	149	126	23
Regulated Electric Utilities – Caribbean[(2)]	**27**	17	10
Non-Regulated – Fortis Generation[(3)]	**16**	30	(14)
Non-Regulated – Fortis Properties[(4)]	**24**	23	1
Corporate and Other	**(71)**	(69)	(2)
Net Earnings Applicable to Common Shares	**262**	245	17

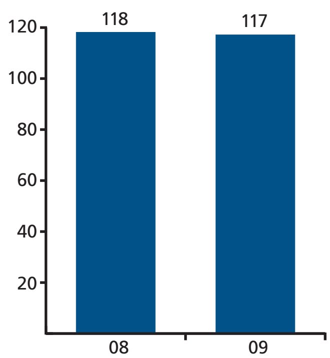
(1) Includes Algoma Power from October 2009

(2) Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, its financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. In 2008, Caribbean Utilities changed its fiscal year end to December 31, which has eliminated the previous two-month lag in consolidating its financial results and resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities for the year ended December 31, 2008. During 2009, the financial reporting periods of the Corporation coincided with the financial reporting periods of Caribbean Utilities.

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

(4) Includes the results of the Holiday Inn Select Windsor from April 2009 and the Sheraton Hotel Newfoundland from November 2008, the dates of acquisition

Regulated Gas Utilities – Canadian Earnings *($ millions)*



REGULATED UTILITIES

The Corporation's primary business is regulated utilities. In 2009, regulated earnings in Canada and the Caribbean represented approximately 88 per cent (2008 – 83 per cent) of the Corporation's earnings from its operating segments (excluding the Corporate and Other segment). Total regulated assets represented 93 per cent of the Corporation's total assets as at December 31, 2009 (December 31, 2008 – 92 per cent).

Regulated Gas Utilities – Canadian

Regulated Gas Utilities – Canadian earnings for 2009 were $117 million (2008 – $118 million), which represented approximately 40 per cent of the Corporation's total regulated earnings (2008 – 45 per cent). Regulated Gas Utilities – Canadian assets were approximately $5.0 billion as at December 31, 2009 (December 31, 2008 – $4.6 billion), which represented approximately 44 per cent of the Corporation's total regulated assets as at December 31, 2009 (December 31, 2008 – 45 per cent).

Terasen Gas Companies

Financial Highlights

Years Ended December 31	**2009**	2008	Variance
Gas Volumes *(TJ)*	**207,230**	221,122	(13,892)
($ millions)			
Revenue	**1,663**	1,902	(239)
Energy Supply Costs	**1,022**	1,268	(246)
Operating Expenses	**268**	253	15
Amortization	**102**	97	5
Finance Charges	**121**	129	(8)
Corporate Taxes	**33**	37	(4)
Earnings	**117**	118	(1)

Gas Volumes: Gas volumes decreased 13,892 TJ, or 6.3 per cent, year over year. The following is a breakdown of gas volumes by major customer category.

Gas Volumes by Major Customer Category

Years Ended December 31

(TJ)	**2009**	2008	Variance
Core – residential and commercial	**125,238**	132,867	(7,629)
Industrial	**6,038**	6,337	(299)
Total sales volumes	**131,276**	139,204	(7,928)
Transportation volumes	**60,067**	63,572	(3,505)
Throughput under fixed revenue contracts	**15,887**	18,346	(2,459)
Total Gas Volumes	**207,230**	221,122	(13,892)

The decrease in gas volumes to core customers was mainly due to lower average consumption as a result of warmer temperatures experienced in the cooler months in 2009 compared to 2008. The decrease in gas volumes for all other customers was mainly due to the negative impact of the economic downturn.

The Terasen Gas companies earn approximately the same margin regardless of whether a customer contracts for the purchase of natural gas or contracts for the transportation only of natural gas.

As a result of the operation of regulator-approved deferral mechanisms, changes in consumption levels and energy supply costs from those forecasted to set customer gas rates do not materially affect earnings.

During 2009, net customer additions at the Terasen Gas companies totalled approximately 8,200, bringing the total customer count to approximately 939,600 as at December 31, 2009. During 2008, net customer additions at the Terasen Gas companies totalled approximately 12,800. Continuing weak housing and construction markets, due to slower economic growth, and growth in multi-family housing, where natural gas use is less prevalent compared to single-family housing, has resulted in lower customer growth year over year.

Revenue: Revenue was approximately $1.7 billion for 2009 compared to $1.9 billion for 2008. The decrease was largely due to the lower commodity cost of natural gas charged to customers and lower consumption, partially offset by higher basic customer delivery rates and the rate revenue accrual related to an increase, effective July 1, 2009, in the allowed ROEs for the Terasen Gas companies.

The allowed ROE was increased to 9.50 per cent from 8.47 per cent for TGI and increased to 10.00 per cent from 9.17 per cent for TGVI and TGWI.

Effective January 1, 2009, basic customer delivery rates at TGI increased approximately 6 per cent while basic customer delivery rates at TGVI increased up to 5 per cent based on customer rate class. The basic customer delivery rates, however, reflected the impact of a decrease in the allowed ROE, effective for the first half of 2009, to 8.47 per cent from 8.62 per cent for TGI and to 9.17 per cent from 9.32 per cent for TGVI and TGWI.

Earnings: Earnings were $117 million for 2009 compared to $118 million for 2008. Excluding a $5.5 million tax reduction during the third quarter of 2008 associated with the settlement of historical corporate tax matters and $6 million ($5 million after tax) of costs associated with the conversion of Whistler customer appliances from propane to natural gas, which increased operating expenses in 2009, earnings were approximately $9.5 million higher year over year. The increase was mainly due to the $6 million after-tax impact of the rate revenue accrual related to the increase in the allowed ROEs, effective July 1, 2009, as discussed above, higher basic customer delivery rates, lower finance charges and a lower effective corporate income tax rate. The increase was partially offset by higher operating expenses due to increased labour and employee-benefit costs, and increased amortization costs due to continued investment in capital assets.

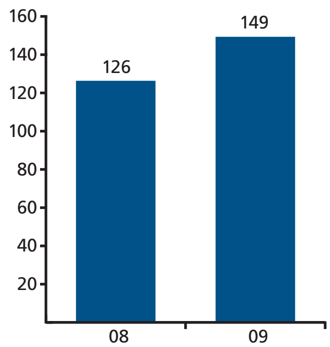
The decrease in the effective corporate income tax rate was primarily due to higher deductions taken for tax purposes compared to accounting purposes in 2009 compared to 2008.

As reflected in basic customer delivery rates for 2009, finance charges were lower year over year due to decreased borrowing rates and lower borrowings under credit facilities.

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

Outlook: Allowed ROEs for 2010 have been set by the regulator at 9.50 per cent for TGI and 10.00 per cent for TGVI and TGWI. The deemed equity component of the total capital structure for TGI has increased, effective January 1, 2010, to 40 per cent. Customer rates at the Terasen Gas companies have been approved by the regulator, effective January 1, 2010.

Regulated Electric Utilities – Canadian Earnings *($ millions)*



A discussion of the nature of regulation and material regulatory decisions and applications pertaining to the Terasen Gas companies is provided under the heading "Regulatory Highlights". A summary of forecast gross capital expenditures for 2010 for the Terasen Gas companies is provided under the heading "Liquidity and Capital Resources – Capital Program".

Regulated Electric Utilities – Canadian

Regulated Electric Utilities – Canadian earnings for 2009 were $149 million (2008 – $126 million), which represented approximately 51 per cent of the Corporation's total regulated earnings (2008 – 48 per cent). Regulated Electric Utilities – Canadian assets were approximately $5.4 billion as at December 31, 2009 (December 31, 2008 – $4.6 billion), which represented approximately 48 per cent of the Corporation's total regulated assets as at December 31, 2009 (December 31, 2008 – 45 per cent).

FortisAlberta

Financial Highlights

Years Ended December 31	**2009**	2008	Variance
Energy Deliveries *(GWh)*	**15,865**	15,722	143
($ millions)			
Revenue	**331**	300	31
Operating Expenses	**132**	130	2
Amortization	**94**	85	9
Finance Charges	**50**	42	8
Corporate Tax Recovery	**(5)**	(3)	(2)
Earnings	**60**	46	14

Energy Deliveries: Energy deliveries at FortisAlberta increased 143 gigawatt hours ("GWh"), or 0.9 per cent, year over year, mainly due to an increase in residential, commercial, farm and irrigation customers, partially offset by a decrease in oilfield customers. Cooler than normal temperatures during the first quarter of 2009 also favourably affected energy deliveries for the year.

As a significant portion of the Company'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: Revenue was $31 million higher than in the previous year, mainly due to an 8.6 per cent increase in customer distribution rates, effective January 1, 2009, reflecting the impact of ongoing investment in electrical infrastructure, and customer and load growth. Revenue also increased due to the rate revenue accrual of approximately $4 million related to the impact of the increase in the allowed ROE to 9.00 per cent, effective January 1, 2009, from an interim allowed ROE of 8.51 per cent and the increase in the deemed equity component of the total capital structure to 41 per cent from 37 per cent for 2009.

Earnings: Earnings were $14 million higher than in the previous year. The impact of the increase in revenue and higher corporate tax recoveries was partially offset by: (i) higher amortization costs associated with continued investment in capital assets; (ii) increased finance charges due to higher debt levels in support of the Company's significant capital expenditure program, partially offset by the impact of lower interest rates on credit facility borrowings; and (iii) higher operating expenses mainly due to higher labour and employee-benefit costs associated with increased salaries and number of employees, partially offset by lower general operating costs. Corporate tax recoveries were higher due to higher future income tax recoveries associated with an increase in regulatory deferrals subject to future income tax recoveries.

Outlook: FortisAlberta's allowed ROE for 2010 has been set by the regulator at 9.00 per cent, unchanged from 2009. An interim customer distribution rate increase of 7.5 per cent, effective January 1, 2010, has been approved by the regulator pending final approval of FortisAlberta's 2010 and 2011 Revenue Requirements Application.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to FortisAlberta is provided under the heading "Regulatory Highlights". A summary of FortisAlberta's forecast gross capital expenditures for 2010 is provided under the heading "Liquidity and Capital Resources – Capital Program".

FortisBC

Financial Highlights

Years Ended December 31	2009	2008	Variance
Electricity Sales *(GWh)*	**3,157**	3,087	70
($ millions)			
Revenue	**253**	237	16
Energy Supply Costs	**72**	68	4
Operating Expenses	**70**	67	3
Amortization	**37**	34	3
Finance Charges	**32**	28	4
Corporate Taxes	**5**	6	(1)
Earnings	**37**	34	3

Electricity Sales: Electricity sales at FortisBC increased 70 GWh, or 2.3 per cent, year over year, primarily due to growth in residential, general service and indirect wholesale customers, partially offset by a decrease in the number of industrial customers. Cooler than normal temperatures during the first quarter of 2009 also favourably impacted electricity sales for the year.

Revenue: Revenue was $16 million higher than in the previous year, driven by: (i) a 4.6 per cent increase in customer electricity rates, effective January 1, 2009; (ii) a 2.2 per cent increase in customer electricity rates, effective September 1, 2009, as a result of the flow through to customers of increased purchased power costs from BC Hydro; and (iii) electricity sales growth, partially offset by a decrease in other revenue driven by an increase in performance-based rate-setting ("PBR") incentive adjustments owing to customers. Customer electricity rates for 2009 reflected the impact of ongoing investment in electrical infrastructure and an allowed ROE of 8.87 per cent compared to 9.02 per cent for 2008.

Earnings: Earnings were $3 million higher than in the previous year. The impact of the increase in customer electricity rates, customer growth and a lower effective corporate income tax rate was partially offset by: (i) higher energy supply costs associated with increased electricity sales and the impact of higher average prices for purchased power, combined with a higher proportion of purchased power versus energy generated from Company-owned hydroelectric generating plants and the receipt of $0.6 million of insurance proceeds during the second quarter of 2008 associated with a turbine failure in 2006; (ii) higher operating expenses mainly due to higher labour costs and general inflationary cost increases, and higher property taxes and water fees; (iii) increased amortization costs associated with continued investment in capital assets; and (iv) higher finance charges, reflecting increased debt levels in support of the Company's capital expenditure program, combined with increased credit facility renewal fees, partially offset by the impact of lower interest rates on credit facility borrowings.

The decrease in the effective corporate income tax rate was due to higher deductions taken for tax purposes compared to accounting purposes in 2009 compared to 2008, combined with a lower statutory income tax rate.

Outlook: FortisBC's allowed ROE for 2010 has been set at 9.90 per cent, up from 8.87 per cent for 2009. In December 2009, FortisBC received regulatory approval of a Negotiated Settlement Agreement ("NSA") pertaining to the Company's 2010 Revenue Requirements Application, resulting in a general customer electricity rate increase of 6.0 per cent, effective January 1, 2010.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to FortisBC is provided under the heading "Regulatory Highlights". A summary of FortisBC's forecast gross capital expenditures for 2010 is provided under the heading "Liquidity and Capital Resources – Capital Program".

Newfoundland Power

Financial Highlights

Years Ended December 31	2009	2008	Variance
Electricity Sales *(GWh)*	**5,299**	5,208	91
($ millions)			
Revenue	**527**	517	10
Energy Supply Costs	**346**	337	9
Operating Expenses	**52**	50	2
Amortization	**46**	45	1
Finance Charges	**34**	33	1
Corporate Taxes	**16**	19	(3)
Non-Controlling Interest	**1**	1	–
Earnings	**32**	32	–

Electricity Sales: Electricity sales at Newfoundland Power increased 91 GWh, or 1.7 per cent, year over year, primarily due to the impact of customer growth and higher average consumption.

Revenue: Revenue was $10 million higher than in the previous year. The increase was driven by increased electricity sales and higher other revenue, partially offset by lower amortization to revenue of certain regulatory liabilities, in accordance with prescribed regulatory orders. The allowed ROE of 8.95 per cent for 2009 remained unchanged from 2008 and, consequently, did not impact customer electricity rates for 2009.

Earnings: Earnings were comparable year over year. Higher electricity sales, an increase in other revenue and a lower effective corporate income tax rate were offset mainly by: (i) the impact of higher demand charges from Newfoundland Hydro, associated with meeting peak load requirements during the winter season; (ii) higher operating expenses, driven by wage, inflationary and regulatory cost increases and an increase in regulator assessment costs due to the timing of the recognition of these costs in 2008, partially offset by a reduction in insurance costs; (iii) increased amortization costs, driven by the impact of continued investment in capital assets; and (iv) higher finance charges, reflecting increased debt levels in support of the Company's capital expenditure program, partially offset by the impact of lower interest rates on credit facility borrowings.

The decrease in the effective corporate income tax rate was primarily due to higher deductions taken for tax purposes compared to accounting purposes in 2009 compared to 2008 and a lower statutory income tax rate.

Outlook: Newfoundland Power's allowed ROE for 2010 has been set at 9.00 per cent, up from 8.95 per cent for 2009. The regulator has approved an overall average increase in basic customer electricity rates of approximately 3.5 per cent, effective January 1, 2010.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to Newfoundland Power is provided under the heading "Regulatory Highlights". A summary of Newfoundland Power's forecast gross capital expenditures for 2010 is provided under the heading "Liquidity and Capital Resources – Capital Program".

Other Canadian Electric Utilities(1)

Financial Highlights

Years Ended December 31	**2009(2)**	2008	Variance
Electricity Sales *(GWh)*	**2,195**	2,182	13
($ millions)			
Revenue	**279**	262	17
Energy Supply Costs	**183**	177	6
Operating Expenses	**32**	28	4
Amortization	**19**	18	1
Finance Charges	**19**	18	1
Corporate Taxes	**6**	7	(1)
Earnings	**20**	14	6

(1) Includes Maritime Electric and FortisOntario

(2) FortisOntario includes financial results of Algoma Power from October 8, 2009.

In October 2009, FortisOntario acquired Great Lakes Power Distribution Inc., subsequently renamed Algoma Power, for an aggregate purchase price of $75 million.

In June 2009, FortisOntario acquired a 10 per cent interest in Grimsby Power for approximately $1 million.

Electricity Sales: Electricity sales at Other Canadian Electric Utilities increased 13 GWh, or 0.6 per cent, year over year. Excluding electricity sales at Algoma Power, electricity sales decreased 33 GWh, or 1.5 per cent, year over year. The decrease was driven by lower average consumption, mainly due to the impact of the economic downturn and the unfavourable impact on consumption due to more moderate temperatures experienced in Ontario in the second and third quarters of 2009, compared to the same periods in 2008, partially offset by the favourable impact on consumption due to cooler temperatures experienced in Ontario in the first quarter of 2009 compared to the same quarter of 2008.

Revenue: Revenue was $17 million higher than in the previous year. Excluding the impact of an approximate $3 million ($2 million after tax) one-time charge at FortisOntario associated with the repayment, during the second quarter of 2008, of a refund received during the fourth quarter of 2007 associated with cross-border transmission interconnection agreements, revenue increased $14 million, $8 million of which related to Algoma Power. The remaining increase in revenue year over year was due to the impact of an average 5.3 per cent increase in customer electricity rates at Maritime Electric, effective April 1, 2009, and a 5.1 per cent, 11.7 per cent and 8.4 per cent increase in customer electricity distribution rates in Fort Erie, Gananoque and Port Colborne, respectively, effective May 1, 2009, partially offset by the impact of lower electricity sales and the flow through to customers of lower energy supply costs at FortisOntario. The higher customer electricity rates at Maritime Electric reflected an increase in the base amount of energy-related costs being expensed and collected from customers and recorded in revenue through the basic rate component of customer billings.

Earnings: Earnings were $6 million higher than in the previous year. Excluding a one-time $3 million favourable adjustment to future income taxes during the fourth quarter of 2009 related to prior periods at FortisOntario and the $2 million after-tax one-time charge at FortisOntario associated with the repayment, during the second quarter of 2008, of the interconnection agreement-related refund, earnings increased $1 million year over year. The increase reflected lower operating expenses at FortisOntario due to the timing of maintenance expenses and a focus on capital projects. Algoma Power contributed $0.1 million to earnings in 2009.

Outlook: In January 2010, Maritime Electric filed a regulatory application requesting an allowed ROE of 9.75 per cent for both 2010 and 2011, unchanged from 2009.

During the first half of 2010, FortisOntario expects to file a new electricity rate application for Algoma Power for rates effective July 1, 2010, using 2010 as a forward test year and an allowed ROE of 9.75 per cent.

Electricity distribution rates for Canadian Niagara Power customers have been approved by the regulator for the period May 1, 2009 through April 30, 2010 and were rebased using 2009 as a forward test year. Regulatory applications were filed in the fourth quarter of 2009, under the Third-Generation Incentive Rate Mechanism, for electricity distribution rates, effective May 1, 2010. An allowed ROE of 9.75 per cent for 2010 will be applicable to utilities in Ontario regulated by the Ontario Energy Board ("OEB"), including FortisOntario, upon filing full cost of service applications in 2010.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to Maritime Electric and FortisOntario is provided under the heading "Regulatory Highlights". A summary of forecast gross capital expenditures for the Other Canadian Electric Utilities for 2010 is provided under the heading "Liquidity and Capital Resources – Capital Program".

Regulated Electric Utilities – Caribbean

Earnings' contribution from Regulated Electric Utilities – Caribbean for 2009 was $27 million (2008 – $17 million), which represented approximately 9 per cent of the Corporation's total regulated earnings (2008 – 7 per cent). Regulated Electric Utilities – Caribbean assets were approximately $0.9 billion as at December 31, 2009 (December 31, 2008 – $1.0 billion), which represented approximately 8 per cent of the Corporation's total regulated assets as at December 31, 2009 (December 31, 2008 – 10 per cent).

Regulated Electric Utilities – Caribbean(1)

Financial Highlights

Years Ended December 31	2009	2008(2)	Variance
Average US:CDN Exchange Rate (3)	**1.13**	1.08	0.05
Electricity Sales *(GWh)*	**1,140**	1,203	(63)
($ millions)			
Revenue	**339**	408	(69)
Energy Supply Costs	**192**	273(4)	(81)
Operating Expenses	**54**	55	(1)
Amortization	**37**	36	1
Finance Charges	**16**	16	–
Corporate Taxes	**2**	2	–
Non-Controlling Interest	**11**	9	2
Earnings	**27**	17	10

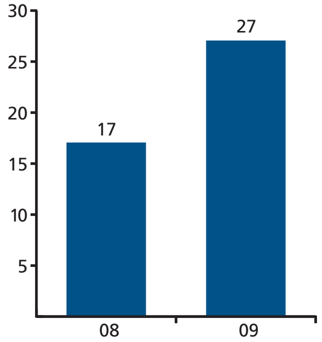
(1) Includes Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos

(2) During 2008, Caribbean Utilities changed its fiscal year end from April 30 to December 31, resulting in the Corporation consolidating 14 months of electricity sales and financial results of Caribbean Utilities for the year ended December 31, 2008. Prior to the fourth quarter of 2008, Fortis was consolidating the financial results of Caribbean Utilities on a two-month lag basis. During 2009, the financial reporting periods of the Corporation coincided with the financial reporting periods of Caribbean Utilities.

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

(4) Energy supply costs during the second quarter of 2008 included an $18 million (BZ$36 million) charge as a result of a regulatory rate decision by the Public Utilities Commission in Belize in June 2008.

Regulated Electric Utilities – Caribbean Earnings *($ millions)*



Electricity Sales: Electricity sales at Regulated Electric Utilities – Caribbean decreased 63 GWh, or 5.2 per cent, year over year. Electricity sales and financial results for the segment for 2008, however, included electricity sales and financial results of Caribbean Utilities for the 14 months ended December 31, 2008, due to a change in the utility's fiscal year end in 2008. When comparing electricity sales for the period from January to December 2009 to the same 12-month period in 2008 for Caribbean Utilities, electricity sales for the segment increased approximately 2 per cent for the year. The increase reflected the loss of electricity sales during the third and fourth quarters of 2008 at Fortis Turks and Caicos as a result of Hurricane Ike, including the delayed reopening for the fall 2008 tourist season of several large hotels on the Turks and Caicos Islands. Hurricane Ike struck the Turks and Caicos Islands in early September 2008. Tempering electricity sales growth year over year, however, was the negative impact of the economic downturn on consumption by residential customers and activities in the tourism, oil, construction and related industries.

Excluding the two additional months of contribution from Caribbean Utilities in 2008, annualized electricity sales growth in 2008 was approximately 6 per cent.

Revenue: Revenue was $69 million lower than in the previous year. Excluding the approximate $13 million favourable impact of foreign exchange associated with the translation of foreign currency-denominated revenue, due to the strengthening of the US dollar relative to the Canadian dollar year over year, revenue decreased approximately $82 million. The decrease was driven by the flow through to customers of lower energy supply costs at Caribbean Utilities and Fortis Turks and Caicos and two additional months of contribution from Caribbean Utilities in fiscal 2008 (November and December 2007). Partially offsetting the above factors was the impact of: (i) a 2.4 per cent increase in basic customer electricity rates at Caribbean Utilities, effective June 1, 2009; (ii) an increase in the cost of power component of the average customer electricity rate at Belize Electricity, effective July 1, 2008; (iii) $1 million associated with a favourable appeal judgment at Fortis Turks and Caicos related to a customer rate classification matter; and (iv) the approximate 2 per cent increase in annualized electricity sales. Tempering revenue growth was the impact of: (i) a decrease in the value-added delivery ("VAD") component of the average customer electricity rate at Belize Electricity, effective July 1, 2008, due to a decrease in the allowed ROA; and (ii) a change in the methodology at Belize Electricity for recording customer installation fees and the impact of refunding certain installation fees previously collected. Customer installation fees at Belize Electricity are now recorded as a capital contribution on the balance sheet rather than as revenue on the statement of earnings.

Earnings: Earnings' contribution was $10 million higher than in the previous year. Excluding: (i) a $13 million reduction in earnings during the second quarter of 2008, representing the Corporation's approximate 70 per cent share of $18 million of disallowed previously incurred fuel and purchased power costs as a result of the June 2008 regulatory rate decision at Belize Electricity; (ii) two additional months of contribution from Caribbean Utilities in fiscal 2008 (November and December 2007) of approximately $1.5 million; and (iii) approximately $1 million associated with favourable foreign currency translation, earnings' contribution decreased $2.5 million year over year. Factors decreasing earnings' contribution included: (i) the lower allowed ROA at Belize Electricity, effective July 1, 2008; (ii) higher operating expenses, excluding foreign exchange impacts, driven by increased employee, legal and regulatory costs and bad debt expense, partially offset by an increase in capitalized general and administrative expenses, as prescribed under Caribbean Utilities' T&D licence, effective April 2008; and (iii) the favourable impact on energy supply costs in 2008 associated with a change in the fuel cost recovery mechanism at Caribbean Utilities. Included in Caribbean Utilities' T&D licence is a new mechanism for the flow through to customers of the cost of fuel and oil, which eliminates favourable or adverse timing differences in fuel and oil cost recovery for reporting periods subsequent to April 30, 2008. The above factors were partially offset by: (i) the approximate $1.5 million favourable impact of a change in depreciation estimates at Fortis Turks and Caicos; (ii) approximately $1 million associated with a favourable appeal judgment at Fortis Turks and Caicos, as described above; and (iii) the favourable impact on energy supply costs in 2009 due to a change in the methodology for calculating the cost of fuel recoverable from customers at Fortis Turks and Caicos in 2009. Earnings were also favourably impacted by the 2.4 per cent basic customer electricity rate increase at Caribbean Utilities and the approximate 2 per cent increase in annualized electricity sales.

Caribbean Utilities met a record peak demand of 97.5 MW in August 2009 and Fortis Turks and Caicos met a combined record peak demand of 29.6 MW in July 2009. In May 2009, Fortis Turks and Caicos commissioned two diesel-powered generating units, increasing the Company's generating capacity by 6.6 MW to 54 MW. Fortis Turks and Caicos has also entered into an agreement with a supplier to purchase two diesel-powered generating units with a combined capacity of approximately 18 MW for a total of approximately US$12 million ($13 million) for delivery in mid-2010 and early 2011.

Outlook: Electricity sales growth at the Corporation's regulated utilities in the Caribbean is expected to be negligible for 2010, reflecting the expected continuation of the negative impact of the economic downturn on consumption by residential customers and activities in the tourism, oil, construction and related industries in the Caribbean region.

In October 2009, the Comisión Federal de Electricidad ("CFE") of Mexico cancelled the guaranteed power supply contract for firm energy with Belize Electricity, citing force majeure reasons. The contract was to mature in December 2010. CFE has stated that its generating capacity has been significantly limited as a result of problems with gas availability, generation equipment and shortfalls in hydroelectric production. CFE is proposing to negotiate a new contract to provide up to 50 MW of economic and emergency energy to Belize Electricity. CFE continues to supply Belize Electricity with power when available. There is sufficient in-country generation to meet energy demand in Belize without supply from CFE.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos is provided under the heading "Regulatory Highlights". A summary of forecast gross capital expenditures for the Regulated Electric Utilities – Caribbean segment for 2010 is provided under the heading "Liquidity and Capital Resources – Capital Program".

NON-REGULATED

Non-Regulated – Fortis Generation[(1)]

Financial Highlights

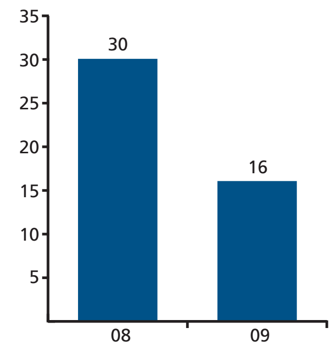
Years Ended December 31	2009[(2)]	2008	Variance
Energy Sales *(GWh)*	**583**	1,217	(634)
($ millions)			
Revenue	**39**	82	(43)
Energy Supply Costs	**2**	7	(5)
Operating Expenses	**11**	14	(3)
Amortization	**5**	10	(5)
Finance Charges	**2**	8	(6)
Corporate Taxes	**3**	10	(7)
Non-Controlling Interest	**–**	3	(3)
Earnings	**16**	30	(14)

(1) Includes the operations of non-regulated generation assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State.

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

Energy Sales: Energy sales from Non-Regulated – Fortis Generation decreased 634 GWh, or 52.1 per cent, year over year. As anticipated, 440 GWh of the total decrease in energy sales was due to the expiration on April 30, 2009, at the end of a 100-year term, of the water rights of the Rankine hydroelectric generating facility in Ontario. In addition, 158 GWh of the total decrease in energy sales related to generation operations in central Newfoundland. Energy sales for 2009 included sales related to central Newfoundland operations for only 1½ months compared to the entire year in 2008, due to the discontinuance of the consolidation method of accounting for these operations in February 2009, necessitated by the actions of the Government of Newfoundland and Labrador related to its expropriation of the assets of the Exploits Partnership (see the "Critical Accounting Estimates – Contingencies" section of this MD&A). The remaining decrease in total energy sales was mainly due to lower production in Belize and Upper New York State. Production levels were primarily a function of rainfall levels, in addition to the impact of maintenance downtime of one unit at the Chalillo hydroelectric generating facility in Belize for about 1½ months during the third quarter of 2009.

Non-Regulated – Fortis Generation Earnings *($ millions)*



Revenue: Revenue was $43 million lower than in the previous year. The primary factors decreasing revenue were: (i) the loss of revenue subsequent to the expiration of the water rights of the Rankine hydroelectric generating facility, as described above; (ii) the impact of the discontinuance of the consolidation method of accounting for the financial results of the hydroelectric generation operations in central Newfoundland during the first quarter of 2009, as described above; (iii) lower average wholesale market energy prices per megawatt hour ("MWh") in Upper New York State, which were US$38.40 for 2009 compared to US$71.10 for 2008; (iv) decreased production in Upper New York State; and (v) lower average wholesale market energy prices per MWh in Ontario related to revenue earned associated with the Rankine facility, which were $36.83 for January through April in 2009 compared to $49.70 for the same period in 2008. The above factors were partially offset by the approximate $2 million favourable impact of foreign currency translation.

Earnings: Earnings were $14 million lower than in the previous year, driven by the expiration of the Rankine water rights, lower average wholesale market energy prices in Upper New York State and Ontario and the impact of lower production in Upper New York State. The decrease in earnings was partially offset by higher interest revenue associated with inter-company lending from non-regulated to regulated operations in Ontario, which reduced finance charges, and the approximate $1 million favourable impact of foreign currency translation. Earnings' contribution associated with the Rankine hydroelectric generating facility was $3.5 million for 2009 compared to approximately $16 million for 2008.

Outlook: The US$53 million 19-MW hydroelectric generating facility at Vaca on the Macal River in Belize will be commissioned in March 2010. The facility is expected to increase average annual energy production from the Macal River by approximately 80 GWh to 240 GWh.

Further information on forecast non-regulated utility capital expenditures for 2010 is provided under the heading "Liquidity and Capital Resources – Capital Program".

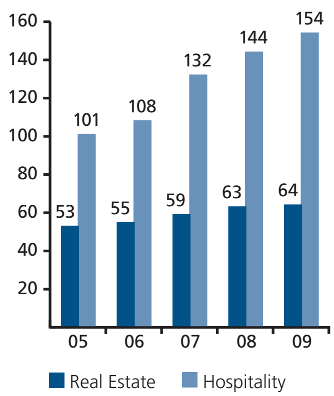
Non-Regulated – Fortis Properties

Financial Highlights

Years Ended December 31

($ millions)	**2009**	2008	Variance
Hospitality Revenue	**154**	144	10
Real Estate Revenue	**64**	63	1
Total Revenue	**218**	207	11
Operating Expenses	**146**	135	11
Amortization	**16**	15	1
Finance Charges	**22**	24	(2)
Corporate Taxes	**10**	10	–
Earnings	**24**	23	1

Fortis Properties Revenue *($ millions)*



Revenue: Hospitality revenue was $10 million higher than in the previous year, driven by revenue contribution from the Sheraton Hotel Newfoundland, which was acquired in November 2008, and the Holiday Inn Select Windsor in Ontario, which was acquired in April 2009, partially offset by decreased revenue in all regions related to the remainder of the Company's hotel operations due to the economic downturn.

Revenue per available room ("RevPAR") was $76.55 for 2009 compared to $80.39 for 2008. The decrease in RevPAR was mainly due to lower occupancies in all of the Company's operating regions, the most significant of which were experienced in western Canada and Ontario.

Real Estate revenue was $1 million higher than in the previous year. The increase reflected growth in all operating regions. The occupancy rate of the Real Estate Division was 96.2 per cent as at December 31, 2009 compared to 96.8 per cent as at December 31, 2008. The decrease in the occupancy rate was primarily associated with a property in rural Newfoundland.

Earnings: Earnings were $1 million higher than in the previous year. Contributions from the Sheraton Hotel Newfoundland and the Holiday Inn Select Windsor, combined with increased contribution from the Real Estate Division and lower finance charges, were partially offset by the impact of generally lower occupancies at the remainder of the Company's hotel operations. Finance charges decreased mainly due to lower external debt balances resulting from regularly scheduled debt repayments.

Operating expenses were $11 million higher than in the previous year, primarily related to the Sheraton Hotel Newfoundland, including non-recurring transitional operating costs incurred during the first quarter of 2009, and the Holiday Inn Select Windsor. The increase was partially offset by overall cost reductions realized in the balance of the Hospitality Division and lower operating expenses incurred at the Real Estate Division. The decrease in operating expenses incurred at the Real Estate Division mainly related to the reclassification to amortization costs during 2009 of certain major operating expenses recoverable from tenants, which were previously deferred and amortized to operating expenses.

Outlook: Same-hotel revenue declined at Fortis Properties' Hospitality Division in 2009 and organic revenue growth will continue to be challenged in 2010 as a result of the economic downturn and its impact on leisure and business travel and hotel stays.

The Real Estate Division operates primarily in Atlantic Canada, where the majority of properties are located in large regional markets that contain a broad economic base. The buildings are occupied by a diversified tenant base characterized by long-term leases with staggered maturity dates to reduce the risk of vacancy exposure.

Corporate and Other[(1)]

Financial Highlights

Years Ended December 31

($ millions)	**2009**	2008	Variance
Revenue	**27**	26	1
Operating Expenses	**14**	16	(2)
Amortization	**8**	8	–
Finance Charges[(2)]	**79**	80	(1)
Corporate Tax Recovery	**(21)**	(23)	2
Preference Share Dividends	**18**	14	4
Net Corporate and Other Expenses	**(71)**	(69)	(2)

(1) Includes Fortis net corporate expenses and the net expenses of non-regulated Terasen corporate-related activities and the financial results of Terasen's 30 per cent ownership interest in CWLP and Terasen's non-regulated wholly owned subsidiary TES

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

Revenue: Revenue was $1 million higher than in the previous year. The increase was driven by higher inter-company interest revenue due to increased inter-company lending, partially offset by lower revenue contribution from CWLP due to the impact of a decrease in the number of customer contracts.

Net Corporate and Other Expenses: Net corporate and other expenses were $2 million higher than in the previous year. Excluding a $1 million favourable corporate tax adjustment at Fortis during 2009 and a $2 million tax reduction recorded in 2008 associated with the settlement of historical corporate tax matters at Terasen, net corporate and other expenses were $1 million higher year over year. The increase was due to higher preference share dividends, due to the issuance of First Preference Shares, Series G during the second quarter of 2008, and lower earnings' contribution from CWLP, partially offset by decreased operating expenses and lower finance charges.

Operating expenses decreased due to lower business development costs at Fortis, partially offset by higher corporate legal and consulting fees and employee-benefit costs at Terasen.

Finance charges decreased as a result of lower average credit facility borrowings in 2009 compared to 2008 and lower interest rates charged on those borrowings, partially offset by interest costs associated with the $200 million 6.51% unsecured debentures issued in July 2009 and the unfavourable impact of foreign exchange associated with the translation of US dollar-denominated interest expense.

In January 2010, Fortis completed a $250 million five-year fixed rate reset preference share offering. The net proceeds of $242 million were used to repay borrowings under the Corporation's committed credit facility and to fund an equity injection into TGI to repay borrowings under the utility's credit facilities in support of working capital and capital expenditure requirements.

Regulatory Highlights

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

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity *(%)*	Allowed Returns *(%)*			Supportive Features
			2008	**2009**	**2010**	**Future or Historical Test Year Used to Set Customer Rates**
				ROE		Cost of Service ("COS")/ROE
TGI	British Columbia Utilities Commission ("BCUC")	40[1]	8.62	8.47 (pre-July 1, 2009) 9.50 (post-July 1, 2009)	9.50	TGI: 50/50 sharing of earnings above or below the allowed ROE under a PBR mechanism that expired on December 31, 2009
TGVI	BCUC	40	9.32	9.17 (pre-July 1, 2009) 10.00 (post-July 1, 2009)	10.00	ROEs established by the BCUC, effective July 1, 2009, as a result of a cost of capital decision in 2009. Previously, the allowed ROEs were set using an automatic adjustment formula tied to long-term Canada bond yields. Future Test Year
FortisBC	BCUC	40	9.02	8.87	9.90	COS/ROE PBR mechanism for 2009 through 2011: 50/50 sharing of earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE – excess to deferral account ROE established by the BCUC, effective January 1, 2010, as a result of a cost of capital decision in 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[2]	8.75	9.00	9.00	COS/ROE ROE established by the AUC, effective January 1, 2009, as a result of a generic cost of capital decision in 2009. Previously, the allowed ROE was set using an automatic adjustment formula tied to long-term Canada bond yields. Future Test Year
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB")	45	8.95 +/– 50 bps	8.95 +/– 50 bps	9.00 +/– 50 bps	COS/ROE ROE for 2010 established by the PUB. Except for 2010, the allowed ROE is set using an automatic adjustment formula tied to long-term Canada bond yields. Future Test Year
Maritime Electric	Island Regulatory and Appeals Commission ("IRAC")	40	10.00	9.75	9.75[3]	COS/ROE Future Test Year
FortisOntario	OEB					
	Canadian Niagara Power	40[4]	9.00	8.01	9.75[5]	Canadian Niagara Power – COS/ROE
	Algoma Power	50	N/A	8.57	9.75	Algoma Power – COS/ROE and subject to Rural Rate Protection Subsidy program
	Franchise Agreement Cornwall Electric					Cornwall Electric – Price cap with commodity cost flow through Canadian Niagara Power – 2004 historical test year for 2008; 2009 test year beginning in 2009 Algoma Power – 2007 historical test year for 2009; 2010 test year for 2010
				ROA		Four-year COS/ROA agreements
Belize Electricity	Public Utilities Commission ("PUC")	N/A	10.00	10.00	–[6]	Additional costs in the event of a hurricane would be deferred and the Company may apply for future recovery in customer rates. Future Test Year
Caribbean Utilities	Electricity Regulatory Authority ("ERA")	N/A	9.00 – 11.00	9.00 – 11.00	7.75 – 9.75	COS/ROA Rate-cap adjustment mechanism based on published consumer price indices Under the new T&D licence, the Company may apply for a special additional rate to customers in the event of a disaster, including a hurricane. Historical Test Year
Fortis Turks and Caicos	Utilities make annual filings with the Energy Commission	N/A	17.50[7]	17.50[7]	17.50[7]	COS/ROA If the actual ROA is lower than the allowed ROA, due to additional costs resulting from a hurricane or other event, the Company may apply for an increase in customer rates in the following year. Future Test Year

(1) Effective January 1, 2010. For 2008 and 2009, the allowed deemed equity component of the capital structure was 35 per cent.
(2) Effective January 1, 2009. For 2008, the allowed deemed equity component of the capital structure was 37 per cent.
(3) Subject to regulatory approval
(4) Effective May 1, 2010. For 2009, effective May 1, the allowed deemed equity component of the capital structure was 43.3 per cent.
(5) Subject to Canadian Niagara Power filing a full cost of service application in 2010
(6) Allowed ROA to be settled once regulatory matters are resolved
(7) Amount provided under licence. Actual ROAs achieved in 2008 and 2009 were materially lower than the ROA allowed under the licence due to significant investment occurring at the utility.

Material Regulatory Decisions and Applications

Regulated Utility	Summary Description
TGI/TGVI	• Every three months TGI and TGVI review natural gas and propane commodity rates with the BCUC in order to ensure the flow-through rates charged to customers are sufficient to cover the cost of purchasing natural gas and propane, while mid-stream rates are reviewed by the BCUC annually in December. As approved by the BCUC, the commodity rate for natural gas was unchanged for most customers and the commodity rate for propane and the mid-stream rate for natural gas decreased, all effective January 1, 2009. Effective April 1, 2009, the BCUC approved decreases in the commodity rates for natural gas and propane. Effective July 1, 2009, the BCUC approved the commodity rate for natural gas as unchanged for customers in most service regions and approved an increase in the commodity rate for propane for customers in Revelstoke. Effective October 1, 2009, the BCUC approved a decrease in commodity rates for natural gas for customers in the Lower Mainland, Fraser Valley and Interior service areas. Effective January 1, 2010, the BCUC approved an increase in mid-stream rates for natural gas and kept commodity rates for natural gas unchanged for customers in the Lower Mainland, Fraser Valley, Interior, North and the Kootenay service areas. The BCUC also approved an increase in commodity rates for propane for customers in Revelstoke, an increase in commodity rates for natural gas for customers in Fort Nelson and a decrease in commodity rates for natural gas for customers in Whistler, effective January 1, 2010. • In December 2008, the BCUC approved a basic customer delivery rate increase of approximately 6 per cent at TGI and approved basic customer delivery rate increases of up to 5 per cent at TGVI based on customer rate class. Basic customer delivery rates for 2009 reflected the decrease in the allowed ROE for 2009 to 8.47 per cent at TGI and to 9.17 per cent at TGVI, resulting from the application of ROE automatic adjustment formulas. • In March 2009, TGI received approval for its application with the BCUC to perform extensive rehabilitation of certain underwater transmission pipeline crossings of the South Arm of the Fraser River, serving Vancouver and Richmond. The project is expected to be completed in 2010 for a total cost of approximately $27 million. • In April 2009, TGI received approval from the BCUC for its new $41.5 million Energy Efficiency and Conservation Program to provide customers with enhanced tools and incentives to manage their natural gas consumption, reduce their energy costs and lower their greenhouse gas emissions. The program began in summer 2009. • In June 2009, the BCUC approved TGI's application requesting to sell LNG as a transportation fuel source for fleet vehicles. • Effective June 1, 2009, the BCUC approved an average 12 per cent decrease in basic customer delivery rates at TGWI. Effective July 1, 2009, the BCUC also approved an approximate 10 per cent decrease in commodity rates at TGWI. • In November and December 2009, the BCUC approved: (i) NSAs pertaining to the 2010 and 2011 Revenue Requirements Applications for TGI and TGVI; (ii) an increase in the deemed equity component of TGI's total capital structure, effective January 1, 2010, to 40 per cent from 35 per cent; (iii) an increase in TGI's allowed ROE, effective July 1, 2009, to 9.50 per cent from 8.47 per cent; and (iv) an increase in the allowed ROE to 10.00 per cent, effective July 1, 2009, from 9.17 per cent for each of TGVI and TGWI. In its decision on the Return on Equity and Capital Structure Application, the BCUC maintained TGI as a benchmark utility for calculating the allowed ROE for certain utilities regulated by the BCUC. The BCUC also determined that the former automatic adjustment formula used to establish the ROE annually will no longer apply and the allowed ROEs as determined in the BCUC decision will apply until reviewed further by the BCUC. The BCUC-approved NSA for TGI did not include a provision to allow the continued use of a PBR mechanism after the expiry, on December 31, 2009, of TGI's previous PBR agreement. The approved mid-year rate base at TGI is approximately $2,540 million for 2010 and $2,634 million for 2011, and the approved mid-year rate base at TGVI is approximately $555 million for 2010 and $729 million for 2011. The overall impact on customer rates, including the effect of changes in the commodity and/or mid-stream rates for natural gas and/or propane, effective January 1, 2010, was: (i) an increase of approximately 10 per cent for residential customers in the Lower Mainland, Fraser Valley, Interior, North and the Kootenays; (ii) an increase of approximately 16 per cent for residential customers in Revelstoke; (iii) a decrease of approximately 12 per cent for customers in Whistler; and (iv) an increase of approximately 8 per cent for customers in Fort Nelson. Customer rates for TGVI's sales customers will remain unchanged for the two-year period beginning January 1, 2010, as provided in the BCUC-approved NSA for TGVI. • In June 2009, TGI filed an application with the BCUC requesting the in-sourcing of core elements of its customer care services and implementation of a new customer information system. Two new call centres and the customer information system are expected to be in place effective January 2012 at a total expected project cost of approximately $116 million, including deferral of certain operating and maintenance expenses. The application was approved in February 2010, upon the Company accepting a cost risk-sharing condition, whereby the Company would share equally with customers any costs or savings outside a band of plus or minus 10 per cent of the approved total project cost.
FortisBC	• In December 2008, the BCUC approved the Company's 2009 Revenue Requirements Application, resulting in a general customer rate increase of 4.6 per cent, effective January 1, 2009. The customer rate increase was primarily the result of the Company's ongoing investment in electrical infrastructure and increasing power purchase prices driven by customer growth and increased electricity demand. Rates for 2009 reflected an allowed ROE of 8.87 per cent as a result of the application of the ROE automatic adjustment formula. The approval of the 2009 Revenue Requirements Application also included an extension of the PBR mechanism for the years 2009 through 2011 under terms similar to the previous PBR agreement, except annual gross operating and maintenance expenses, before capitalized overhead, will be set by a formula incorporating customer growth and inflation, i.e., the consumer price index ("CPI") for British Columbia minus a productivity improvement factor ("PIF") of 3 per cent in 2009, 1.5 per cent in 2010 and 1.5 per cent in 2011. Should inflation be in excess of 3 per cent, the excess is to be added to the PIF, which effectively caps the CPI at 3 per cent.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisBC (cont'd)	• In February 2009, the BCUC issued its decision on FortisBC's 2009 and 2010 Capital Expenditure Plan. Total gross capital expenditures of $165 million were approved for 2009 and $156 million for 2010. • In August 2009, FortisBC applied for and received BCUC approval for a 2.2 per cent increase in customer rates, effective September 1, 2009. The increase was due to higher power purchase costs being charged to the Company by BC Hydro. • In December 2009, the BCUC approved an NSA pertaining to FortisBC's 2010 Revenue Requirements Application. The result was a general customer electricity rate increase of 6.0 per cent, effective January 1, 2010. The rate increase was primarily the result of the Company's ongoing investment in infrastructure, increasing power supply costs and the higher cost of capital. FortisBC's allowed ROE has increased to 9.90 per cent, effective January 1, 2010, from 8.87 per cent in 2009 as a result of the BCUC decision to increase the allowed ROE of TGI, the benchmark utility in British Columbia. The BCUC-approved NSA assumes a mid-year rate base of approximately $975 million for 2010.
FortisAlberta	• In December 2008, FortisAlberta received regulatory approval for its 2009 distribution rates to recover approved distribution costs. The result was a distribution rate increase of 8.6 per cent, effective January 1, 2009. The rate increase was slightly higher than the rate increase of 7.3 per cent contemplated in the 2008/2009 NSA, due to the deferred recovery in customer rates in 2009 of the increase in the allowed ROE to 8.75 per cent in 2008. The approved rates for 2009 also reflected the impact of the Company's union agreement, which was settled after the 2008/2009 NSA was approved. • In June 2009, FortisAlberta filed a comprehensive two-year Distribution Revenue Requirements Application for 2010 and 2011. The application forecasts a mid-year rate base of approximately $1,538 million for 2010 and $1,724 million for 2011. The expected impact on the distribution component of customer rates is an average increase of 13.3 per cent for 2010 and 14.9 per cent for 2011, before considering the impact of the increase in the allowed ROE and the deemed equity component of the total capital structure, as per the AUC Generic Cost of Capital Decision. The incremental effect of the final approved 2009 ROE and capital structure, as described below, is expected to be collected in customer electricity rates in 2010. New customer electricity rates to be established for 2010 will reflect an allowed ROE of 9.00 per cent on a deemed equity component of the total capital structure of 41 per cent. FortisAlberta anticipates a regulatory decision by the AUC to be received in spring 2010 with final customer electricity rates anticipated to take effect in late 2010 or early 2011. An interim approval of customer electricity rates by the AUC has resulted in an overall 7.5 per cent average increase in base customer distribution electricity rates at FortisAlberta, effective January 1, 2010. • In November 2009, the AUC issued its decision on the 2009 Generic Cost of Capital Proceeding, establishing a generic allowed ROE for all Alberta utilities it regulates of 9.00 per cent for each of 2009 and 2010. The allowed ROE of 9.00 per cent is up from 8.61 per cent that the former ROE automatic adjustment formula would have provided for FortisAlberta in 2009. The ROE automatic adjustment formula will no longer apply until reviewed further by the AUC. The AUC also increased the deemed equity component of FortisAlberta's total capital structure to 41 per cent from 37 per cent, effective January 1, 2009. Two hundred basis points of the increase in the equity component of the capital structure reflected the effects of FortisAlberta having become a non-taxable utility for rate-setting purposes. The AUC also ordered that the generic allowed ROE for Alberta utilities that it regulates, including FortisAlberta, be established on an interim basis for 2011 at 9.00 per cent. The establishment of an interim ROE level was chosen because the AUC was not prepared to reimpose an adjustment formula without the opportunity to assess changes in the capital markets and to reconsider the types of factors that should be built into a formula.
Newfoundland Power	• In November 2008, the PUB approved, as filed, the Company's 2009 Capital Budget Application for approximately $62 million, with approximately half of the proposed capital expenditures relating to construction and capital maintenance of the electricity system. During the third quarter of 2009, Newfoundland Power filed supplemental applications to its 2009 Capital Budget Application, requesting an additional approximate $2 million in capital spending, which were approved by the PUB. • The Company's allowed ROE of 8.95 per cent for 2009 remained unchanged from 2008 and, consequently, did not impact customer electricity rates for 2009. • Effective July 1, 2009, the PUB approved an overall average decrease in customer electricity rates of approximately 6.6 per cent, reflecting the flow through to customers, by operation of the Rate Stabilization Account, of variances in the cost of fuel used to generate electricity that Newfoundland Hydro sells to Newfoundland Power. The decrease in customer electricity rates had no impact on Newfoundland Power's earnings in 2009. • In November 2009, the Company's 2010 Capital Budget Application totalling approximately $65 million was approved by the PUB. • In December 2009, the PUB issued a decision on Newfoundland Power's 2010 General Rate Application, resulting in an overall average increase in basic customer electricity rates of approximately 3.5 per cent, effective January 1, 2010, including the impact of an increase in the allowed ROE to 9.00 per cent from 8.95 per cent in 2009, as set by the PUB for 2010. The PUB decision assumes a mid-year rate base of approximately $869 million for 2010. The PUB also ordered that Newfoundland Power's allowed ROE for each of 2011 and 2012 be determined using the ROE automatic adjustment formula. The ROE automatic adjustment formula is subject to a review by the PUB in the first quarter of 2010.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
Maritime Electric	• In March 2009, IRAC approved Maritime Electric's 2009 Rate Application, which resulted in an increase in the base amount of energy-related costs being expensed and collected from customers and recorded in revenue through the basic rate component of customer billings, effective April 1, 2009. The increase in the reference cost of energy in basic rates from 6.73 cents per kilowatt hour ("kWh") to 7.7 cents per kWh resulted in a decrease in the amount of energy costs collected from customers through the operation of the Energy Cost Adjustment Mechanism ("ECAM"). Additionally, IRAC approved the deferral of the New Brunswick Power ("NB Power") Point Lepreau Nuclear Generating Station ("Point Lepreau") replacement energy costs for 2009 and an increase in the amortization period of the ECAM to 12 months, effective April 1, 2009. IRAC also approved, as filed, a maximum allowed ROE of 9.75 per cent for 2009, down from an allowed ROE of 10.00 per cent for 2008. The overall impact on residential customer electricity rates for 2009 was an increase of 5.3 per cent based on average consumption of 650 kWh per month. • In September 2009, NB Power announced that the refurbishment of Point Lepreau was behind schedule with the target date for electricity to be generated again delayed until early 2011. The Point Lepreau reactor was originally scheduled to restart October 1, 2009. • In October 2009, Maritime Electric received regulatory approval, as filed, of its 2010 Capital Budget Application totalling $22 million, before customer contributions. • In October 2009, Maritime Electric received regulatory approval of the extension of its energy purchase agreement with NB Power to December 31, 2010. The agreement, originally entered into in April 2008, was set to expire in September 2009 when Point Lepreau was to return to service. Delays in the refurbishment and resulting return to service date of Point Lepreau required an extension of the energy purchase agreement. • In January 2010, Maritime Electric filed an application with IRAC: (i) providing a report on the impact of the rebasing of the ECAM deferral account in 2009 and requesting an increase in the reference cost of energy in basic rates from 7.7 cents per kWh to 9.4 cents per kWh, effective April 1, 2010, and from 9.4 cents per kWh to 9.6 cents per kWh, effective April 1, 2011; (ii) requesting that the replacement energy costs incurred during the refurbishment of Point Lepreau be amortized over a period of 25 years, representing the extended life of the unit; and (iii) requesting an allowed ROE of 9.75 per cent for both 2010 and 2011, unchanged from 2009.
FortisOntario	• In August 2009, the OEB issued its Rate Order for Fort Erie and Gananoque, approving final distribution rate increases using 2009 as a forward test year, effective May 1, 2009, of 5.1 per cent and 11.7 per cent, respectively, with impact on customer billings commencing September 1, 2009. Foregone revenue from May 1, 2009 through August 31, 2009 will be recovered from customers through a rate rider in effect from September 1, 2009 through April 30, 2010. The Rate Order confirmed a deemed capital structure containing 43.3 per cent equity, approved an allowed ROE of 8.01 per cent for 2009 and approved all forecast capital expenditures and significantly all forecast operating expenses, as filed. The approved rate increases were primarily driven by the impact of distribution system upgrades. • In September and October 2009, the OEB held a stakeholder conference to determine whether current economic and financial market conditions warranted an adjustment to any cost of capital. In December 2009, the OEB issued its *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities.* Based on current economic indicators, a preliminary allowed ROE has been set at 9.75 per cent for utilities in Ontario regulated by the OEB. The ROE formula has been refined to reduce sensitivity to changes in long-term Canada bond yields and includes an additional factor for utility bond spreads. The updated allowed ROE will come into effect for the setting of customer rates beginning in 2010 by way of a cost of service application. • In October and November 2009, FortisOntario filed Third-Generation Incentive Rate Mechanism ("IRM") electricity distribution rate applications for harmonized rates for Fort Erie and Gananoque and rates for Port Colborne, effective May 1, 2010, based on a deemed capital structure containing 40 per cent equity. In non-rebasing years, customer electricity rates are set using inflationary factors less an efficiency target under the OEB's Third-Generation IRM. • In October 2009, the OEB issued its Rate Order for Port Colborne, approving a final electricity rate increase using 2009 as a forward test year, effective May 1, 2009, of 8.4 per cent, with impact on customer billings commencing November 1, 2009. Foregone revenue from May 1, 2009 through October 31, 2009 will be recovered from customers through a rate rider in effect from November 1, 2009 through April 30, 2011. The Rate Order confirmed a deemed capital structure containing 43.3 per cent equity and approved an allowed ROE of 8.01 per cent for 2009. • FortisOntario expects to file a new electricity rate application for Algoma Power during the first half of 2010 for rates effective July 1, 2010, using 2010 as a forward test year and an allowed ROE of 9.75 per cent.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
Belize Electricity	• In June 2008, the PUC issued its Final Decision on Belize Electricity's 2008/2009 Rate Application, which rejected most of the recommendations of a PUC-appointed Independent Expert engaged to review the PUC's Initial Decision on Belize Electricity's 2008/2009 Rate Application and failed to increase the overall average electricity rate, as requested in the application. The PUC also ordered a BZ$36 million retroactive adjustment associated with Belize Electricity's prior years' financial results. The adjustment, in substance, represented the disallowance of previously incurred fuel and purchased power costs. The PUC also reduced Belize Electricity's targeted allowed ROA to 10 per cent from 12 per cent through a reduction in the VAD component of the average electricity rate. As a direct result of the June 2008 Final Decision, Belize Electricity recorded an $18 million (BZ$36 million) charge ($13 million of which was the Corporation's share) to energy supply costs during the second quarter of 2008. The Final Decision does not affect the Corporation's hydroelectric generation operations conducted in BECOL. • The Final Decision also proposed the use of an automatic mechanism, to be finalized by the PUC, to adjust monthly, on a two-month lag basis, the cost of power component of the rate to reflect actual costs of power. The automatic adjustment mechanism, which was retroactively effective September 1, 2008, allows for the recovery from, or refund to, customers of the actual cost of power that varies from a reference cost of power by more than a threshold of 10 per cent. • In February 2009, the PUC amended the Final Decision on Belize Electricity's 2008/2009 Rate Application (the "Amendment"), effective for the period from January 1, 2009 through June 30, 2009. The Amendment provides for an increase in the VAD component of the average electricity rate to allow Belize Electricity to earn a targeted allowed ROA of 12 per cent but reduces the reference cost of power component of the average electricity rate, due to an overall decline in the cost of power. The Amendment, therefore, allows for an overall decrease in the average electricity rate from BZ44.1 cents per kWh to BZ37.5 cents per kWh. The Amendment also provides for a lower regulated asset value upon which the allowed ROA is calculated, while increasing operating expenses by the same amount, and reduces depreciation, taxes and fees and the related revenue requirement. • In April 2009, Belize Electricity filed its Annual Tariff Review Application for the annual tariff period from July 1, 2009 to June 30, 2010 (the "2009/2010 Rate Application") proposing a 6 per cent decrease in the average electricity rate, as well as a reversal of the BZ$36 million charge described above. The PUC has not accepted the 2009/2010 Rate Application on the grounds that an Annual Tariff Review Proceeding is not in effect. • Changes made in electricity legislation by the Government of Belize and the PUC, and the PUC's June 2008 Final Decision and the Amendment, which were based on the changed legislation, have been judicially challenged by Belize Electricity in several proceedings. The judicial process is ongoing with interim rulings, judgments and appeals. The timing or likely final outcome of the proceedings is indeterminable at this time. The Supreme Court of Belize issued an injunction against the Amendment until Belize Electricity's appeal of the June 2008 Final Decision has been heard in court. The court appeal of the June 2008 Final Decision was called in early October 2009 but, after considering some preliminary matters, the trial judge postponed the case for a date to be determined. In addition, Belize Electricity's appeal of the Supreme Court of Belize's previous decision to uphold certain changes made in electricity legislation by the Government of Belize and the PUC was dismissed in June 2009. • In June 2009, the Government of Belize issued a statutory instrument purporting to declare providers of electricity generation and water services, including BECOL, as public utility providers within the meaning of the *Public Utilities Commission Act* as of May 1, 2009. Fortis continues to assess the statutory instrument and its impact on previously negotiated and PUC-approved power purchase agreements.
Caribbean Utilities	• In March 2009, the ERA approved the Company's 2009 Capital Investment Plan ("CIP") of US$48 million. • In April 2009, Caribbean Utilities submitted its bid to install 16 MW of generation in May 2012 and another 16 MW of generation in May 2013. There was one other bidder for the 32 MW of generation. In September 2009, based on economic conditions and revised medium-term future load growth projections by Caribbean Utilities, the ERA cancelled its 32 MW capacity-expansion solicitation. Caribbean Utilities and the ERA will continue to monitor growth indicators and revise forecasts as necessary. A new solicitation may occur at such time as there are indicators of a future need for additional capacity. • The ERA approved a 2.4 per cent increase in basic customer electricity rates, effective June 1, 2009, in accordance with Caribbean Utilities' T&D licence. • In February 2010, the ERA approved Caribbean Utilities' 2010–2014 CIP at US$98 million for non-generation expansion expenditures. The 2010–2014 CIP submitted by Caribbean Utilities to the ERA in October 2009 totalled US$157 million, which included approximately US$59 million for estimated costs associated with future generation expansion to be solicited.
Fortis Turks and Caicos	• In March 2009, Fortis Turks and Caicos submitted its 2008 annual regulatory filing outlining the Company's performance in 2008 and its capital expansion plans for 2009.

Consolidated Financial Position

The following table outlines the significant changes in the consolidated balance sheets of Fortis between December 31, 2009 and December 31, 2008.

Significant Changes in the Consolidated Balance Sheets between December 31, 2009 and December 31, 2008

Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Accounts receivable	(86)	The decrease was primarily due to warmer temperatures, lower natural gas commodity prices at the Terasen Gas companies and lower fuel costs at Caribbean Utilities and Fortis Turks and Caicos.
Regulatory assets – current and long-term	621	The increase was primarily due to recording $560 million in regulatory assets as at December 31, 2009, associated with the recognition of future income taxes upon adoption of amended Section 3465, *Income Taxes*, effective January 1, 2009. The remainder of the increase was mainly due to: (i) the deferral at the Terasen Gas companies of the change in the fair market value of the natural gas derivatives and of actual net mid-stream natural gas costs in excess of the amounts collected in customer rates in 2009; (ii) the deferral of Point Lepreau energy replacement costs at Maritime Electric; and (iii) the 2009 AESO charges deferral account at FortisAlberta. The increase was partially offset by the impact of the deferral of amounts collected in customer rates in excess of the actual commodity cost of natural gas at the Terasen Gas companies during 2009.
Inventories	(51)	The decrease was primarily associated with lower natural gas commodity prices.
Other assets	(56)	The decrease was driven by a $61 million reduction associated with the discontinuance of the consolidation method of accounting for the Corporation's interest in the Exploits Partnership, effective February 12, 2009, partially offset by higher accrued pension assets at Newfoundland Power, due to pension funding being in excess of pension expense for 2009. Refer to the "Critical Accounting Estimates – Contingencies" section of this MD&A for a further discussion of the Exploits Partnership.
Utility capital assets	546	The increase primarily related to $966 million invested in electricity and gas systems, partially offset by amortization, customer contributions and the impact of foreign exchange on the translation of foreign currency-denominated utility capital assets.
Accounts payable and accrued charges	(22)	The decrease was driven by lower amounts owing for purchased natural gas at the Terasen Gas companies, due to lower natural gas prices and volumes, partially offset by a $30 million increase associated with the change in the fair market value of the natural gas derivatives at the Terasen Gas companies.
Dividends payable	(44)	The decrease was due to the timing of the declaration of common share dividends.
Income taxes payable	(43)	The decrease was mainly due to the timing of income tax payments at the Terasen Gas companies and Newfoundland Power.
Regulatory liabilities – current and long-term	55	The increase was primarily due to recording $35 million in regulatory liabilities as at December 31, 2009, associated with the recognition of future income taxes upon adoption of amended Section 3465, *Income Taxes*, effective January 1, 2009. Regulatory liabilities also increased due to the lower cost of fuel and purchased power at Belize Electricity during 2009 compared to amounts collected in customer rates during 2009 and the deferral of the margin impact of actual customer consumption exceeding forecast consumption during 2009 at the Terasen Gas companies. The increase was partially offset by the deferral of actual net mid-stream natural gas costs in excess of amounts collected in customer rates at the Terasen Gas companies during 2009.
Future income tax liabilities – current and long-term	524	The increase was primarily due to the recognition of future income taxes upon adoption of amended Section 3465, *Income Taxes*, effective January 1, 2009.

Significant Changes in the Consolidated Balance Sheets between December 31, 2009 and December 31, 2008 (cont'd)

Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Long-term debt and capital lease obligations (including current portion)	376	The increase was primarily due to the issuance of long-term debt, partially offset by a net $14 million repayment of committed credit facility borrowings and a $61 million decrease associated with the discontinuance of the consolidation method of accounting for the Corporation's interest in the Exploits Partnership, effective February 12, 2009; regularly scheduled debt repayments and debt maturities; and the impact of foreign exchange on the translation of foreign currency-denominated debt. Refer to the "Critical Accounting Estimates – Contingencies" section of this MD&A for a further discussion of the Exploits Partnership. The issuance of long-term debt, primarily to repay committed credit facility borrowings, short-term borrowings and maturing debt, was comprised of a $100 million debenture offering by TGI, a $225 million debenture offerings by FortisAlberta, a $65 million bond offering by Newfoundland Power, a US$40 million note offering by Caribbean Utilities, a $105 million debenture offering by FortisBC and a $200 million debenture offering by Fortis. The net $14 million decrease in committed credit facility borrowings was driven by net repayments at FortisAlberta and Newfoundland Power, partially offset by net borrowings at the Corporation. The regularly scheduled debt repayments included the repayment of $60 million of maturing debt at TGI and $50 million of maturing debt at FortisBC.
Non-controlling interest	(22)	The decrease primarily related to the impact of foreign exchange on the translation of US dollar-denominated non-controlling interest amounts, combined with Fortis increasing its controlling ownership in Caribbean Utilities by 2.7 per cent in July 2009.
Shareholders' equity	147	The increase was mainly due to net earnings applicable to common shares for 2009, less common share dividends. The remainder of the increase related to the issuance of common shares under the Corporation's share purchase, dividend reinvestment and stock option plans, partially offset by an increase in accumulated other comprehensive loss.

Liquidity and Capital Resources

The table below outlines the Corporation's sources and uses of cash in 2009 compared to 2008, followed by a discussion of the nature of the variances in cash flows year over year.

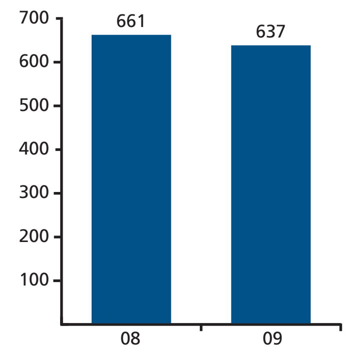
Summary of Cash Flows

Years Ended December 31

($ millions)	**2009**	2008	Variance
Cash, Beginning of Year	**66**	58	8
Cash Provided By (Used In)			
Operating Activities	**637**	661	(24)
Investing Activities	**(1,052)**	(852)	(200)
Financing Activities	**438**	196	242
Foreign Currency Impact on Cash Balances	**(4)**	3	(7)
Cash, End of Year	**85**	66	19

Operating Activities: Cash flow from operating activities, after working capital adjustments, in 2009 was $24 million lower than in the previous year. The decrease was mainly due to the timing of the declaration of common share dividends, the timing and an increase in the amount of corporate income taxes paid at Newfoundland Power and unfavourable working capital changes at the Terasen Gas companies reflecting differences in the commodity cost of natural gas and the cost of natural gas charged to customers year over year. The decrease was partially offset by favourable changes in the AESO charges deferral account at FortisAlberta.

Cash Flow from Operating Activities
($ millions)



Investing Activities: Cash used in investing activities in 2009 was $200 million higher than in the previous year. Investing activities in 2009, however, reflected the acquisition of Algoma Power for approximately $70 million, net of cash acquired, and the Holiday Inn Select Windsor for approximately $7 million. Investing activities in 2008 reflected the acquisition of the Sheraton Hotel Newfoundland for approximately $22 million. Excluding the impact of business acquisitions in 2009 and 2008, cash used in investing activities increased year over year due to higher gross capital expenditures and lower contributions in aid of construction.

Gross capital expenditures in 2009 were $1,024 million, $89 million higher than in 2008. The increase was driven by higher utility capital asset spending at FortisAlberta and the Terasen Gas companies.

Financing Activities: Cash provided by financing activities in 2009 was $242 million higher than in the previous year, mainly due to higher proceeds from long-term debt, lower repayments of long-term debt, and lower net repayments under committed credit facilities and short-term borrowings, partially offset by lower proceeds from common share and preference share issues.

Net short-term borrowings were $8 million for 2009 compared to net repayment of short-term borrowings of $69 million for 2008. The increase in cash provided by changes in short-term borrowings was driven by the Terasen Gas companies and Maritime Electric.

Proceeds from long-term debt, net of issue costs, repayments of long-term debt and capital lease obligations and net borrowings (repayments) under committed credit facilities for 2009 compared to 2008 are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs

Years Ended December 31

($ millions)	**2009**	2008	Variance
Terasen Gas Companies	**99**[(1)]	496[(2)(3)]	(397)
FortisAlberta	**222**[(4)(5)]	99[(6)]	123
FortisBC	**104**[(7)]	–	104
Newfoundland Power	**64**[(8)]	–	64
Maritime Electric	**–**	60[(9)]	(60)
Caribbean Utilities	**43**[(10)]	–	43
Corporate – Fortis	**197**[(11)]	–	197
Other	**–**	7	(7)
Total	**729**	662	67

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

(2) Issued May 2008, 30-year $250 million 5.80% unsecured debentures by TGI. The net proceeds were primarily used to repay maturing $188 million 6.20% debentures and short-term borrowings.

(3) Issued February 2008, 30-year $250 million 6.05% unsecured debentures by TGVI. The net proceeds were used to repay committed credit facility borrowings.

(4) Issued October 2009, 30-year $125 million 5.37% unsecured debentures. The net proceeds were used to repay committed credit facility borrowings and for general corporate purposes.

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

(6) Issued April 2008, 30-year $100 million 5.85% unsecured debentures. The net proceeds were used to repay committed credit facility borrowings.

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

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

(9) Issued April 2008, 30-year $60 million 6.05% secured first mortgage bonds. The proceeds were used to repay short-term borrowings.

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

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

Repayments of Long-Term Debt and Capital Lease Obligations

Years Ended December 31

($ millions)	**2009**	2008	Variance
Terasen Gas Companies	**(62)**	(193)	131
FortisBC	**(55)**	–	(55)
Newfoundland Power	**(5)**	(5)	–
Caribbean Utilities	**(16)**	(11)	(5)
Fortis Properties	**(24)**	(13)	(11)
Corporate – Terasen	**–**	(200)	200
Other	**(10)**	(9)	(1)
Total	**(172)**	(431)	259

Net Borrowings (Repayments) Under Committed Credit Facilities

Years Ended December 31

($ millions)	**2009**	2008	Variance
Terasen Gas Companies	**5**	(261)	266
FortisAlberta	**(99)**	101	(200)
FortisBC	**4**	31	(27)
Newfoundland Power	**(18)**	(1)	(17)
Corporate	**94**	(179)	273
Total	**(14)**	(309)	295

Borrowings under credit facilities by the utilities are primarily in support of their respective 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. During the third quarter of 2009, a net repayment of $144 million under the Corporation's committed credit facility was financed with partial proceeds from the issuance of $200 million unsecured debentures ($197 million net of costs). During the second quarter of 2008, a net repayment of $170 million under the Corporation's committed credit facility was financed with partial proceeds from the issuance of $230 million preference shares ($223 million net of costs).

Net proceeds associated with the issuance of common shares under the Corporation's share purchase and stock option plans in 2009 were $46 million compared to $21 million in 2008, reflecting the impact, effective March 1, 2009, of the Corporation's Dividend Reinvestment and Share Purchase Plan. The Dividend Reinvestment and Share Purchase Plan provides participating common shareholders a 2 per cent discount on the purchase of common shares, issued from treasury, with reinvested dividends. In December 2008, the Corporation publicly issued 11.7 million common shares for gross proceeds of approximately $300 million ($287 million net of costs). The net proceeds were used to repay short-term debt primarily incurred to retire $200 million of debt at Terasen that matured on December 1, 2008, and for general corporate purposes.

Common share dividends were $133 million for 2009, down $29 million from 2008. The decrease was a result of the timing of the declaration of common share dividends, partially offset by a higher number of common shares outstanding during 2009, primarily as a result of the public issuance of 11.7 million common shares in December 2008. The dividend declared per common share was $0.78 in 2009 compared to $1.01 in 2008.

Preference share dividends increased $4 million year over year as a result of the dividends associated with the 9.2 million First Preference Shares, Series G that were issued during the second quarter of 2008.

Contractual Obligations: Consolidated contractual obligations of Fortis for periods over the next five years and thereafter, as at December 31, 2009, are outlined in the following table.

Contractual Obligations

As at December 31, 2009 *($ 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[(1)]	**5,502**	222	312	797	4,171
Brilliant Terminal Station[(2)]	**62**	3	5	5	49
Gas purchase contract obligations[(3)]	**746**	387	193	166	–
Power purchase obligations					
FortisBC[(4)]	**2,921**	42	83	78	2,718
FortisOntario[(5)]	**509**	46	95	99	269
Maritime Electric[(6)]	**66**	47	2	2	15
Belize Electricity[(7)]	**327**	26	65	69	167
Capital cost[(8)]	**383**	15	40	42	286
Joint-use asset and shared service agreements[(9)]	**62**	4	6	6	46
Office lease – FortisBC[(10)]	**19**	1	4	3	11
Operating lease obligations[(11)]	**147**	17	31	27	72
Equipment purchase – Fortis Turks and Caicos[(12)]	**12**	8	4	–	–
Other	**30**	12	12	5	1
Total	**10,786**	830	852	1,299	7,805

(1) In prior years, TGVI received non-interest bearing repayable loans from the federal and provincial governments of $50 million and $25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. The government loans are repayable in any fiscal year prior to 2012 under certain circumstances and subject to the ability of TGVI to obtain non-government subordinated debt financing on reasonable commercial terms. As the loans are repaid and replaced with non-government loans, utility capital assets, long-term debt and equity requirements will increase in accordance with TGVI's approved capital structure, as will TGVI's rate base, which is used in determining customer rates. The repayment criteria were met in 2009 and TGVI is expected to make a $4 million repayment on the loans in 2010 (2009 – $8 million). As at December 31, 2009, the outstanding balance of the repayable government loans was $53 million, with $4 million classified as current portion of long-term debt. Repayments of the government loans beyond 2010 are not included in the contractual obligations table above as the amount and timing of the repayments are dependent upon the ability of TGVI to replace the government loans with non-government subordinated debt financing on reasonable commercial terms. TGVI, however, estimates making payments under the loans of $20 million in 2012, $14 million over 2013 and 2014 and $15 million thereafter.

(2) On July 15, 2003, FortisBC began operating the Brilliant Terminal Station ("BTS") under an agreement, the term of which expires in 2056 (unless the Company has earlier terminated the agreement by exercising its right, at any time after the anniversary date of the agreement in 2029, to give 36 months' notice of termination). The BTS is jointly owned by CPC/CBT and is used by the Company on its own behalf and on behalf of CPC/CBT. The agreement provides that FortisBC will pay CPC/CBT a charge related to the recovery of the capital cost of the BTS and related operating costs.

(3) Gas purchase contract obligations relate to various gas purchase contracts at the Terasen Gas companies. These obligations are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect as at December 31, 2009.

(4) Power purchase obligations for FortisBC include the Brilliant Power Purchase Agreement (the "BPPA"), as well as the power purchase agreement with BC Hydro. On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the BTS located near Castlegar, British Columbia. The BPPA requires payments based on the operation and maintenance costs and a return on capital for the plant in exchange for the specified take-or-pay amounts of power. The BPPA includes a market-related price adjustment after 30 years of the 60-year term. The power purchase agreement with BC Hydro, which expires in 2013, provides for any amount of supply up to a maximum of 200 MW but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements.

(5) Power purchase obligations for FortisOntario primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of electricity and capacity. The first contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The second contract, supplying the remainder of Cornwall Electric's energy requirements, provides 100 MW of capacity and energy and provides a minimum of 300 GWh of energy per contract year. Both contracts expire in December 2019.

(6) Maritime Electric has two take-or-pay contracts for the purchase of either capacity or energy. The take-or-pay contract with NB Power includes, among other things, replacement energy and capacity for Point Lepreau during its refurbishment outage, and the contract expires in December 2010. The other take-or-pay contract is for transmission capacity allowing Maritime Electric to reserve 30 MW of capacity on the new international power line into the United States and expires in November 2032.

(7) Power purchase obligations for Belize Electricity include a 15-year power purchase agreement, which commenced in February 2007, between Belize Electricity and Hydro Maya Limited for the supply of 3 MW of capacity. In addition, two 15-year power purchase agreements commenced in 2009 with Belize Cogeneration Energy Limited and Belize Aquaculture Limited to provide for the supply of approximately 14 MW of capacity and up to 15 MW of capacity, respectively.

In October 2009, the CFE of Mexico cancelled the guaranteed power supply contract for firm energy with Belize Electricity, citing force majeure reasons. The contract was to mature in December 2010.

(8) Maritime Electric has entitlement to approximately 6.7 per cent of the output from the NB Power Dalhousie Generating Station and approximately 4.7 per cent from Point Lepreau for the life of each unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital costs of these units.

(9) FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until FortisAlberta no longer has attachments to the transmission facilities. Due to the unlimited term of this contract, the calculation of future payments after 2014 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time. FortisAlberta and an Alberta transmission service provider have also entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. The service agreements have minimum expiry terms of five years from September 1, 2005 and are subject to extension based on mutually agreeable terms.

(10) Under a sale-leaseback agreement, on September 29, 1993, FortisBC began leasing its Trail, British Columbia office building for a term of 30 years. The terms of the agreement grant FortisBC repurchase options at approximately year 20 and year 28 of the lease term.

(11) Operating lease obligations include certain office, warehouse, natural gas T&D asset, vehicle and equipment leases, and the lease of electricity distribution assets of Port Colborne Hydro.

(12) Fortis Turks and Caicos has entered into an agreement with a supplier to purchase two diesel-powered generating units with a combined capacity of approximately 18 MW for delivery in mid-2010 and early 2011.

Other Contractual Obligations: Caribbean Utilities has a primary fuel supply contract with a major supplier and is committed to purchase 80 per cent of the Company's fuel requirements from this supplier for the operation of Caribbean Utilities' diesel-powered generating plant. The contract is for three years terminating in April 2010, with 9 million imperial gallons required to be purchased during 2010. The contract contains an automatic renewal clause for the years 2010 through 2012. Should any party choose to terminate the contract within that two-year period, notice must be given a minimum of one year in advance of the desired termination date.

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

Pension Funding: The fair value of the Corporation's consolidated defined benefit pension plan assets increased approximately 14 per cent, or $82 million, during 2009, commensurate with the recovery in the capital markets. This increase compares to a decrease of approximately 14 per cent, or $95 million, during 2008 mainly due to unfavourable market conditions during that year. Details of the nature of the changes in the fair value of the plan assets are disclosed in Note 20 to the Corporation's 2009 Consolidated Financial Statements.

Market-driven changes impacting the performance of pension plan assets and the discount rate may result in material changes in future pension funding requirements and/or net pension cost. The decline in fair value of the pension plan assets during 2008 did not materially affect the Corporation's consolidated defined benefit plan funding contributions for 2009.

Consolidated defined benefit pension funding contributions, including current service, solvency and special funding amounts, are expected to be $20 million in 2010, $8 million in 2011, $4 million in 2012 and $3 million in 2013. Fortis expects defined benefit pension plan funding contributions to be sourced primarily from a combination of cash generated from operations and amounts available for borrowing under existing credit facilities. The contributions above, however, 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 as follows for the larger defined benefit pension plans:

December 31, 2009	Terasen (covering non-unionized employees)
December 31, 2010	Terasen (covering unionized employees) and FortisBC
December 31, 2011	Newfoundland Power

Consolidated defined benefit pension funding contributions for 2009 were not materially impacted by the outcome of the actuarial valuations as at December 31, 2008 for defined benefit pension plans at Newfoundland Power and the Corporation, and as at December 31, 2007 for one of the defined benefit pension plans at Terasen, which were completed during the first quarter of 2009.

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

The consolidated capital structure of Fortis as at December 31, 2009 compared to December 31, 2008 is presented in the following table.

Capital Structure

As at December 31	**2009**		2008	
	($ millions)	*(%)*	*($ millions)*	*(%)*
Total debt and capital lease obligations (net of cash)[(1)]	**5,830**	**60.2**	5,468	59.5
Preference shares[(2)]	**667**	**6.9**	667	7.3
Common shareholders' equity	**3,193**	**32.9**	3,046	33.2
Total	**9,690**	**100.0**	9,181	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

The slight change in the capital structure was driven by higher debt levels, primarily in support of infrastructure investment, and increased accumulated other comprehensive loss, driven by unfavourable foreign exchange, partially offset by net earnings applicable to common shares, net of common share dividends, of $129 million and increased common shares outstanding reflecting the impact of the Corporation's enhanced Dividend Reinvestment and Share Purchase Plan.

The Corporation's credit ratings are as follows:

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

In September 2009, S&P confirmed its credit rating for Fortis at A– (stable outlook). The credit ratings reflect the diversity of the operations of Fortis, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level and the continued focus of Fortis on pursuing the acquisition of stable regulated utilities.

Capital Program: The Corporation's principal businesses of regulated gas and electricity distribution are capital intensive. Capital investment in infrastructure is required to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred. Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred. During 2009, approximately $91 million in maintenance and repairs was expensed compared to approximately $90 million during 2008.

Gross consolidated capital expenditures for the year ended December 31, 2009 were more than $1 billion. A breakdown of gross capital expenditures by segment and asset category for 2009 is provided in the following table.

Gross Capital Expenditures(1)

Year Ended December 31, 2009

($ millions)	Terasen Gas Companies	Fortis Alberta(2)	Fortis BC	Newfoundland Power	Other Regulated Electric Utilities – Canadian	**Total Regulated Utilities – Canadian**	**Regulated Electric Utilities – Caribbean**	**Non-Regulated – Utility(3)**	**Fortis Properties**	**Total**
Generation	–	–	19	10	3	**32**	**45**	**14**	**–**	**91**
Transmission	118	–	49	5	8	**180**	**12**	**–**	**–**	**192**
Distribution	97	269	32	52	32	**482**	**27**	**–**	**–**	**509**
Facilities, equipment, vehicles and other	15	128	10	3	2	**158**	**6**	**3**	**26**	**193**
Information technology	16	10	5	4	1	**36**	**2**	**1**	**–**	**39**
Total	246	407	115	74	46	**888**	**92**	**18**	**26**	**1,024**

(1) Relates to utility capital assets, income producing properties and intangible assets and includes capital expenditures associated with assets under construction. Includes asset removal and site restoration expenditures, net of salvage proceeds, for those utilities where such expenditures were permissible in rate base in 2009. Excludes capitalized non-cash equity component of the Allowance for Funds Used During Construction ("AFUDC").

(2) Includes payments made to AESO for investment in transmission capital projects

(3) Includes non-regulated utility and Corporate capital expenditures

Actual gross consolidated capital expenditures for 2009 were comparable to those forecasted and disclosed in the MD&A for the year ended December 31, 2008. An increase in capital spending at FortisAlberta associated with higher than anticipated customer-driven capital expenditures, including new customer connections, and the inclusion of AESO transmission capital expenditures in total capital expenditures was offset mainly by: (i) a shift from 2009 to 2010 of some capital spending related to the Vaca hydroelectric generating project and certain projects at the Terasen Gas companies and FortisBC; (ii) lower than forecasted capital spending at non-regulated TES; and (iii) lower spending at FortisBC associated with the Okanagan Transmission Reinforcement Project.

Gross consolidated capital expenditures for 2010 are expected to be approximately $1.1 billion. Planned capital expenditures are based on detailed forecasts of energy demand, weather and cost of labour and materials, as well as other factors, including economic conditions, which could change and cause actual expenditures to differ from forecasts.

A breakdown of forecast gross capital expenditures by segment and asset category for 2010 is provided in the following table.

Forecast Gross Capital Expenditures(1)

Year Ending December 31, 2010

($ millions)	Terasen Gas Companies	Fortis Alberta(2)	Fortis BC	Newfoundland Power	Other Regulated Electric Utilities – Canadian	**Total Regulated Utilities – Canadian**	**Regulated Electric Utilities – Caribbean**	**Non-Regulated – Utility(3)**	**Fortis Properties**	**Total**
Generation	–	–	19	6	3	**28**	**28**	**16**	**–**	**72**
Transmission	146	–	92	7	3	**248**	**10**	**–**	**–**	**258**
Distribution	100	212	38	47	37	**434**	**31**	**–**	**–**	**465**
Facilities, equipment, vehicles and other	64	139	15	4	2	**224**	**12**	**–**	**26**	**262**
Information technology	17	12	4	5	2	**40**	**1**	**–**	**–**	**41**
Total	327	363	168	69	47	**974**	**82**	**16**	**26**	**1,098**

(1) Relates to utility capital assets, income producing properties and intangible assets and includes forecast capital expenditures associated with assets under construction. Includes forecast asset removal and site restoration expenditures, net of salvage proceeds, for those utilities where such expenditures are permissible in rate base. Excludes forecast capitalized non-cash equity component of AFUDC.

(2) Includes forecast payments to be made to AESO for investment in transmission capital projects

(3) Includes forecast non-regulated utility and Corporate capital expenditures

The percentage breakdown of 2009 actual and 2010 forecast gross capital expenditures among growth, sustaining and other is as follows:

Gross Capital Expenditures

Year Ended December 31 *(%)*	**Actual 2009**	Forecast 2010
Growth	**47**	41
Sustaining[(1)]	**30**	32
Other[(2)]	**23**	27
Total	**100**	100

[(1)] Capital expenditures required to ensure continued and enhanced performance, reliability and safety of generation and T&D assets

[2)] Relates to facilities, equipment, vehicles, information technology systems and other assets, including Automated Meter Infrastructure ("AMI") and the in-house customer care enhancement project at TGI

Significant capital projects for 2009 and 2010 are summarized in the table below.

Significant Capital Projects[(1)]

($ millions) **Company**	**Nature of project**	Pre-2009	**Actual 2009**	Forecast 2010	Forecast costs to complete after 2010	Year of expected completion
Terasen Gas Companies	LNG storage facility – Vancouver Island	47	**71**	66	27	2011
	Squamish-to-Whistler pipeline lateral and system conversion	39	**15**	2	–	2009
	Customer Care Enhancement Project	–	**1**	31	84	2012
	Fraser River South Bank South Arm Rehabilitation Project	1	**7**	19	–	2010
FortisAlberta	AMI technology	24	**58**	64	9	2011
FortisBC	Okanagan Transmission Reinforcement Project	7	**22**	63	18	2011
	Transmission Projects	65	**17**	14	20	2013
	Generation asset Upgrade and Life-Extension Program	17	**13**	15	20	2012
Caribbean Utilities	New 16-MW diesel-powered generating unit	8	**22**	–	–	2009
Non-Regulated – Fortis Generation	19-MW Vaca hydroelectric generating facility in Belize	32	**13**	14	–	2010
Fortis Properties	Expansion of Holiday Inn Express Kelowna	1	**9**	2	–	2010

[(1)] Relates to property, plant and equipment expenditures in addition to capitalized interest and non-cash equity components of AFUDC

In April 2008, TGVI received BCUC approval to proceed with the engineering, procurement and construction of an LNG storage facility. Construction commenced in 2008 and continued during 2009 with the facility expected to be in service by late 2011. The total capital cost of this project is estimated at approximately $211 million.

TGVI's construction of the 50-kilometre Squamish-to-Whistler natural gas pipeline lateral was completed during spring 2009, with conversion of Whistler customer appliances completed in August 2009. The total project cost of the pipeline construction and conversion of the appliances is estimated at approximately $56 million, $8 million higher than the amount previously approved by the BCUC for this project. A provision for approximately $5 million after-tax related to the additional costs associated with the conversion of the appliances has been expensed to earnings in the fourth quarter of 2009. However, applications have been filed with the BCUC requesting inclusion in rate base of the total additional costs. The pipeline lateral and appliance conversion were required as part of the overall conversion of TGWI's propane distribution system to a natural gas distribution system.

In June 2009, TGI filed an application with the BCUC requesting the in-sourcing of core elements of its customer care service and for implementation of a new customer information system. Two new call centres and the customer information system are expected to be in place effective January 2012 at an expected project cost of approximately $116 million, including deferral of certain operating and maintenance expenses. The application was approved in February 2010, upon the Company accepting a cost risk-sharing condition, whereby the Company would share equally with customers any additional costs or savings outside a band of plus or minus 10 per cent of the approved total project cost.

The Fraser River South Bank South Arm Rehabilitation Project was approved by the BCUC in March 2009 and involves the installation and replacement of underwater transmission pipeline crossings that are at potential risk of failure from a major seismic event. The project is estimated to cost approximately $27 million and is expected to be in service in 2010.

FortisAlberta continued the replacement of conventional customer meters with new AMI technology during 2009. In response to the direction of the Alberta Department of Energy on AMI capabilities, FortisAlberta has adjusted the scope of its planned AMI program, which is now expected to cost approximately $155 million, up from $124 million as disclosed in the MD&A for the year ended December 31, 2008. Additional capital costs may be incurred under this project, pending clarification of meter data reporting requirements by the appropriate government agencies. The final project cost is subject to regulatory approval.

FortisBC began construction on the approximate $110 million Okanagan Transmission Reinforcement Project in July 2009, with completion expected in mid-2011. The total forecast cost of the project is down from the original estimate of $141 million as disclosed in the MD&A for the year ended December 31, 2008. The decrease in cost is mainly due to lower forecasted labour, equipment and commodity costs. The project relates to upgrading the existing overhead transmission lines from 161 kilovolts ("kV") to 230 kV between Penticton and Oliver and building a new 230-kV terminal in the Oliver area.

During 2009 several major transmission projects were completed at FortisBC. The Company forecasts an additional $34 million in capital spending related to major transmission growth-related projects from 2010 through 2013, of which $20 million is subject to regulatory approval.

Since 1998, a major life extension of hydroelectric generating facilities has been underway at FortisBC, involving the rebuilding of 11 of the 15 hydroelectric generating units in the utility's four generating plants. Eight units have been rebuilt to date and the program is scheduled for completion in 2012. The upgrades will improve efficiency, safety and environmental stewardship and will maintain the overall reliability of the plants. FortisBC forecasts approximately $35 million in additional BCUC-approved capital spending related to this initiative from 2010 through 2012.

In 2009, Caribbean Utilities commissioned a 16-MW diesel-powered generating unit for a total project cost of approximately $30 million.

The US$53 million Vaca hydroelectric generating facility will be commissioned in March 2010. The facility is expected to increase average annual energy production from the Macal River in Belize by approximately 80 GWh to 240 GWh.

The seven-storey, 70-room, 4,500-square feet of meeting room space expansion to the Holiday Inn Express Kelowna was completed in February 2010 at a total cost of $12 million.

Over the five-year period 2010 through 2014, consolidated gross capital expenditures are expected to approach $5 billion. Approximately 70 per cent of the capital spending is expected to be incurred at the Regulated Electric Utilities, driven by FortisAlberta and FortisBC. Approximately 27 per cent of the capital spending is expected to be incurred at the Regulated Gas Utilities and 3 per cent is expected to be incurred at the non-regulated operations. Capital expenditures at the Regulated Utilities are subject to regulatory approval.

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

The Corporation's ability to service its debt obligations and pay dividends on its common shares 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 its 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.

The Corporation does not expect any significant decrease in subsidiary operating cash flows in 2010 as a result of any continuation of the economic downturn. The subsidiaries expect to be able to source the cash required to fund their 2010 capital expenditure programs.

Management expects consolidated long-term debt maturities and repayments to be approximately $220 million in 2010 and 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 will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets. For a discussion of capital resources and liquidity risk, refer to the "Business Risk Management – Capital Resources and Liquidity Risk" section of this MD&A.

As a result of the regulator's Final Decision on Belize Electricity's 2008/2009 Rate Application in June 2008, Belize Electricity does not meet certain debt covenant financial ratios, related to loans with the International Bank for Reconstruction and Development and the Caribbean Development Bank totalling $7 million (BZ$12 million) as at December 31, 2009. The Company has informed the lenders of the defaults and has requested appropriate waivers.

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 $59 million as at December 31, 2009 (December 31, 2008 – $61 million). The lenders of the term loan have not demanded accelerated repayment. A further discussion of the Exploits Partnership is provided in the "Critical Accounting Estimates – Contingencies" section of this MD&A.

Except for the debt at Belize Electricity and the Exploits Partnership, as described above, Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2009 and are expected to remain compliant in 2010.

Credit Facilities: As at December 31, 2009, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.2 billion, of which approximately $1.4 billion was unused, including $476 million unused under the Corporation's $600 million committed revolving credit facility. The credit facilities are syndicated almost entirely with the seven largest Canadian banks, with no one bank holding more than 25 per cent of these facilities.

Approximately $2.0 billion of the total credit facilities are committed facilities, the majority of which have maturities between 2011 and 2013.

The cost of renewed and extended credit facilities may increase as a result of current economic conditions; however, any increase in interest expense and/or fees is not expected to materially impact the Corporation' consolidated financial results in 2010, as the majority of the total committed credit facilities have maturities between 2011 and 2013.

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

Credit Facilities

($ millions)	Corporate and Other	Regulated Utilities	Fortis Properties	**Total as at December 31, 2009**	Total as at December 31, 2008
Total credit facilities	645	1,495	13	**2,153**	2,228
Credit facilities utilized:					
Short-term borrowings	–	(409)	(6)	**(415)**	(410)
Long-term debt (including current portion)	(125)	(83)	–	**(208)**	(224)
Letters of credit outstanding	(1)	(98)	(1)	**(100)**	(104)
Credit facilities unused	519	905	6	**1,430**	1,490

At December 31, 2009 and 2008, 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.

Significant changes in total credit facilities from December 31, 2008 to December 31, 2009 are described below. The nature and terms of the credit facilities outstanding as at December 31, 2009 are detailed in Note 26 to the 2009 Consolidated Financial Statements.

Corporate and Other

In May 2009, Terasen entered into a $30 million unsecured committed revolving credit facility maturing in May 2011, to replace its $100 million committed revolving credit facility that matured in May 2009. The terms of the new credit facility are substantially the same as those of the credit facility it replaced.

Regulated Utilities

In April 2009, FortisBC amended its $150 million unsecured committed revolving credit facility, including extending the maturity date of the $50 million portion of the facility to May 2012 from May 2011 and extending the maturity date of the $100 million portion of the facility to May 2010 from May 2009.

FortisBC expects to have its $100 million 364-day committed revolving credit facility, due to mature in May 2010, extended for a further 364 days.

Maritime Electric expects to have its $50 million 364-day committed revolving credit facility, due to mature in March 2010, extended for a further 364 days.

Off-Balance Sheet Arrangements

As at December 31, 2009, 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

The following is a summary of the Corporation's significant business risks.

Regulatory Risk: The Corporation's key business risk is regulation. Each of the Corporation's regulated utilities is subject to some form of regulation that can affect future revenue and earnings. Management at each utility is responsible for working closely with its regulator and local government to ensure both compliance with existing regulations and the proactive management of regulatory issues.

Approximately 93 per cent of the Corporation's operating revenue was derived from regulated utility operations in 2009 (2008 – 93 per cent), while approximately 88 per cent of the Corporation's operating earnings, before corporate and other net expenses, were derived from regulated utility operations in 2009 (2008 – 83 per cent). The Corporation's regulated utilities are subject to the normal uncertainties faced by regulated entities, including approvals by the respective regulatory authority of gas and electricity rates that permit a reasonable opportunity to recover, on a timely basis, the estimated costs of providing services, including a fair rate of return on rate base and, in the case of Caribbean Utilities and Fortis Turks and Caicos, the continuation of licences. Generally, the ability of the utilities to recover the actual costs of providing services and to earn the approved ROEs and/or ROAs depends on achieving the forecasts established in the rate-setting processes. Upgrades of, and additions to, gas and electricity infrastructure require the approval of the regulatory authorities either through the approval of capital expenditure plans or regulatory approval of revenue requirements for the purpose of setting electricity and gas rates, which include the impact of capital expenditures on rate base and/or cost of service. There is no assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved or that conditions to such approvals will not be imposed. Capital cost overruns subject to such approvals might not be recoverable. In addition, there is no assurance that the regulated utilities will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

Rate applications that establish revenue requirements may be subject to negotiated settlement procedures, as well as pursued through public hearing processes. There can be no assurance that rate orders issued will permit the Corporation's utilities to recover all costs actually incurred and to earn the expected rates of return. A failure to obtain acceptable rate orders may adversely affect the business carried on by the utilities, the undertaking or timing of proposed capital projects, ratings assigned by rating agencies, the issuance and sale of securities and other matters, which may, in turn, negatively affect the results of operations and financial position of the Corporation's utilities.

Although Fortis considers the regulatory frameworks in most of the jurisdictions it operates in to be fair and balanced, uncertainties do exist at the present time. The June 2008 regulatory decision related to Belize Electricity's 2008/2009 Rate Application and changes in electricity legislation made by the Government of Belize and the PUC create uncertainty in the regulatory regime and the rate-setting process in Belize and violate both established regulatory practice and contractual obligations made by the Government of Belize at the time Fortis made its initial investment in Belize Electricity.

Although all of the Corporation's regulated utilities currently operate under cost of service and/or rate of return on rate base methodologies, PBR and other rate-setting mechanisms, such as ROE automatic adjustment formulas, are also being employed to varying degrees. A discussion of the impact of changes in interest rates on allowed ROEs is provided in the "Business Risk Management – Interest Rate Risk" section of this MD&A.

TGI and FortisBC are regulated by the BCUC and have, from time to time, used PBR mechanisms. PBR mechanisms provide utilities an opportunity to earn returns in excess of the allowed ROEs determined by the regulator. The current PBR mechanism at FortisBC extends through 2011. Upon expiry of the PBR mechanism, there is no certainty as to whether a new PBR mechanism will be entered into or what the particular terms of any renewed PBR mechanism will be.

The PBR mechanism at TGI expired at the end of 2009 and the BCUC-approved rate settlement agreement reached at TGI pertaining to 2010 and 2011 revenue requirements did not provide for the continuation of a PBR mechanism after December 2009. Under the 2010 and 2011 rate settlement agreements reached at both TGI and TGVI, certain cost of service variances are subject to deferral account treatment and the balances are at the respective company's risk.

Additional information on the PBR mechanisms at TGI and FortisBC, and the nature of regulation and various regulatory matters pertaining to the Corporation's utilities, is provided in the "Regulatory Highlights" section of this MD&A.

Operating and Maintenance Risks: The Terasen Gas companies are exposed to various operational risks, such as: pipeline leaks; accidental damage to, or fatigue cracks in, mains and service lines; corrosion in pipes; pipeline or equipment failure; other issues that can lead to outages and/or leaks; and any other accidents involving natural gas that could result in significant operational disruptions and/or environmental liability. The Terasen Gas companies maintain comprehensive facility risk assessment, pipeline integrity management and damage prevention programs, and pipeline security systems as preventive measures to mitigate the risk of a pipeline failure or other loss of system integrity. The business of electricity transmission and distribution is also subject to operational risks including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. The infrastructure of the subsidiaries is also exposed to the effects of severe weather conditions and other acts of nature. In addition, a significant portion of the infrastructure is located in remote areas, which may make access difficult for repair of damage due to weather conditions and other acts of nature. The Terasen Gas companies and FortisBC operate facilities in a terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, avalanches and similar acts of nature. The Terasen Gas companies, FortisBC and, to a lesser extent, the Corporation's operations in the Caribbean region, are subject to risk of loss from earthquakes. The Corporation and its subsidiaries have insurance that provides coverage for business interruption, liability and property damage, although the coverage offered by this insurance is limited. In the event of a large uninsured loss caused by severe weather conditions or other natural disasters, application will be made to the respective regulatory authority for the recovery of these costs through higher rates to offset any loss. However, there can be no assurance that the regulatory authorities would approve any such application in whole or in part. See the "Business Risk Management – Insurance Coverage Risk" section of this MD&A for a further discussion on insurance.

The Corporation's gas and electricity systems require ongoing maintenance, improvement and replacement. Accordingly, to ensure the continued performance of the physical assets, the utilities determine expenditures that must be made to maintain and replace the assets. If the systems are not able to be maintained, service disruptions and increased costs may be experienced. The inability to obtain regulatory approval to reflect in rates the expenditures the utilities believe are necessary to maintain, improve and replace assets; the failure by the utilities to properly implement or complete approved capital expenditure programs; or the occurrence of significant unforeseen equipment failures, despite maintenance programs, could have a material effect on the operations of the utilities.

The Corporation's utilities continually develop capital expenditure programs and assess current and future operating and maintenance expenses that will be incurred in the ongoing operation of their gas and electricity systems. Management's analysis is based on assumptions as to cost of service and equipment, regulatory requirements, revenue requirement approvals and other matters, which involve some degree of uncertainty. If actual costs exceed regulator-approved capital expenditures, it is uncertain whether any additional costs will receive regulatory approval for recovery in future customer rates. The inability to recover these additional costs could have a material effect on the financial condition and results of operations of the utilities.

Economic Conditions: Typical of utilities, economic conditions in the Corporation's service territories influence energy sales. Energy sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices and housing starts. Also, in the service territories in which the Terasen Gas companies operate, the level of new multi-family housing starts is continuing to outpace that of new single-family housing starts. Natural gas has a lower penetration rate in multi-family housing; therefore, growth in gas distribution volumes may be tempered. In the Caribbean, the level of, and fluctuations in, tourism and related activities, which are closely tied to economic conditions, influence electricity sales as they affect electricity demand of the large hotels and condominium complexes that are serviced by the Corporation's regulated utilities in that region.

Higher energy prices can result in reduced consumption by customers. Natural gas and crude oil exploration and production activities in certain of the Corporation's service territories are closely correlated with natural gas and crude oil prices. The level of these activities can influence energy demand, affecting local energy sales in some of the Corporation's service territories.

An extended decline in economic conditions would be expected to have the effect of reducing demand for energy over time. The regulated nature of utility operations, including various mitigating measures approved by regulators, helps to reduce the impact that lower energy demand, associated with poor economic conditions, may have on the utilities' earnings. However, a severe and prolonged downturn in economic conditions could materially affect the utilities, despite regulatory measures available to compensate for reduced demand. For instance, significantly reduced energy demand in the Corporation's service territories could reduce capital spending, which would, in turn, affect rate base and earnings' growth.

In addition to the impact of reduced energy demand, an extended decline in economic conditions could also impair the ability of customers to pay for gas and electricity consumed, thereby affecting the aging and collection of the utilities' trade receivables.

Fortis also holds investments in both commercial office and retail space and hotel properties. The hotel properties, in particular, are subject to operating risks associated with industry fluctuations and local economic conditions. Fortis Properties' real estate exposure to lease expiries averages approximately 9 per cent per annum over the next five years. Approximately 56 per cent of Fortis Properties' operating income was derived from hotel investments in 2009 (2008 – 57 per cent). Same-hotel revenue declined at Fortis Properties' Hospitality Division in 2009 from 2008 and organic revenue growth will continue to be challenged in 2010 as a result of the economic downturn and its impact on leisure and business travel and hotel stays. It is estimated that a 10 per cent decrease in revenue at the Hospitality Division would decrease annual basic earnings per common share of Fortis by approximately 2 cents.

Capital Resources and Liquidity Risk: The Corporation's 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 results of operations and the 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. Funds generated from operations after payment of expected expenses (including interest payments on any outstanding debt) will not be sufficient to fund the repayment of all outstanding liabilities when due, as well as all anticipated capital expenditures. There can be no assurance that sufficient capital will continue to be available on acceptable terms to repay existing debt and to fund capital expenditures.

The Corporation and its currently rated regulated utilities are subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. Credit ratings affect the level of credit risk spreads on new long-term debt issues and on the Corporation's and its utilities' credit facilities. A change in the credit ratings could potentially affect access to various sources of capital and increase or decrease finance charges of the Corporation and its utilities. Also, a significant downgrade in the credit ratings of TGI or Terasen could trigger margin calls and other cash requirements under TGI's natural gas purchase and natural gas derivative contracts. As discussed in the "Liquidity and Capital Resources – Capital Structure" section of this MD&A, the Corporation's corporate investment-grade credit ratings by S&P were confirmed and maintained during the third quarter of 2009. During 2009, the only changes in credit ratings for the Corporation's currently rated utilities were for Newfoundland Power, TGI and Caribbean Utilities. In August 2009, Moody's upgraded the credit rating of Newfoundland Power's first mortgage bonds from Baa1 to A2 and of TGI's secured debentures from A2 to A1. In November 2009, S&P changed the outlook on Caribbean Utilities' issuer credit rating from A(stable) to A(negative) as a result of pressures facing the Cayman Islands economy and concern that it could create a more difficult operating environment for Caribbean Utilities in the next few years. Fortis and its regulated utilities do not anticipate any material adverse rating actions by the credit rating agencies in the near term. However, the global financial crisis has placed increased scrutiny on rating agencies and rating agency criteria, which may result in changes to credit rating practices and policies.

Despite volatility in the global capital markets, the Corporation and its utilities have been successful at raising long-term capital at reasonable rates. However, continued volatility in the global capital markets may increase the cost, and affect the timing, of issuance of long-term capital by the Corporation and its utilities. While the cost of borrowing may increase, the Corporation and its utilities expect to continue to have reasonable access to capital in the near to medium terms. The cost of renewed and extended credit facilities may also increase going forward; however, any increase in interest expense and/or fees is not expected to materially impact the Corporation's consolidated financial results in 2010 as the majority of the total credit facilities have maturities between 2011 and 2013. As the Corporation's utilities are regulated under cost of service, any increased cost of borrowing at the utilities is eligible to be recovered in customer rates.

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 committed credit facility at the Corporation is available for interim financing of acquisitions and for general corporate purposes.

Further information on the Corporation's credit facilities, contractual obligations, including long-term debt maturities and repayments, and consolidated cash flow requirements is provided in the "Liquidity and Capital Resources" section of this MD&A and under "Liquidity Risk" in Note 26 to the 2009 Consolidated Financial Statements.

Weather and Seasonality: The physical assets of the Corporation and its subsidiaries are exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed and are operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. At Newfoundland Power, exposure to climatic factors is addressed through the operation of a regulator-approved weather normalization reserve. The operation of this reserve mitigates year-to-year volatility in earnings that would otherwise be caused by variations in weather conditions. At TGI, a BCUC-approved rate stabilization account serves to mitigate the effect on earnings of volume volatility, caused principally by weather, by allowing TGI to accumulate the margin impact of variations in the actual versus forecast gas volumes consumed by customers.

At the Terasen Gas companies, weather has a significant impact on distribution volume, as a major portion of the gas distributed is ultimately used for space heating for residential customers. Because of gas-consumption patterns, the Terasen Gas companies normally generate quarterly earnings that vary by season and may not be an indicator of annual earnings. Most of the annual earnings of the Terasen Gas companies are generated in the first and fourth quarters.

Fluctuations in the amount of electricity used by customers can vary significantly in response to seasonal changes in weather. In Canada, cool summers may reduce air-conditioning demand while less severe winters may reduce electric heating load. In the Caribbean, the impact of seasonal changes in weather on air-conditioning demand is less pronounced due to the less variable climatic conditions that prevail in the region. Significant fluctuations in weather-related demand for electricity could materially impact the operations, financial condition and results of operations of the electric utilities.

Despite preparation for severe weather, extraordinary conditions such as hurricanes and other natural disasters will always remain a risk to utilities. The Corporation uses a centralized insurance management function to create a higher level of insurance expertise and reduce its liability exposure.

The assets and earnings of Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos are subject to hurricane risk. Similar to other Fortis utilities, these companies manage weather risks through insurance on generation assets, business-interruption insurance and self-insurance on T&D assets. In Belize, additional costs in the event of a hurricane would be deferred and the Company may apply for future recovery in customer rates. Under its T&D licence, Caribbean Utilities may apply for a special additional customer rate in the event of a disaster, such as a hurricane. Fortis Turks and Caicos does not have a specific hurricane cost recovery mechanism; however, the Company may apply for an increase in customer rates in the following year if the actual ROA is lower than the allowed ROA due to additional costs resulting from a hurricane or other significant event.

Earnings from non-regulated generation assets are sensitive to rainfall levels but the geographic diversity of the Corporation's generation assets mitigates the risk associated with rainfall levels.

Commodity Price Risk: The Terasen Gas companies are exposed to commodity price risk associated with changes in the market price of natural gas. The companies employ a number of tools to reduce exposure to natural gas price volatility. These tools include purchasing gas for storage and adopting hedging strategies, which include a combination of both physical and financial transactions, to reduce price volatility and ensure, to the extent possible, that natural gas costs remain competitive with electricity rates. The use of natural gas derivatives effectively fixes the price of natural gas purchases. Activities related to the hedging of gas prices are currently approved by the BCUC and gains or losses effectively accrue entirely to customers. The operation of BCUC-approved rate stabilization accounts to flow through in customer rates the commodity cost of natural gas serves to mitigate the effect on earnings of natural gas cost volatility.

Most of the Corporation's regulated electric utilities are exposed to commodity price risk associated with changes in world oil prices, which affects the cost of fuel and purchased power. The risk is substantially mitigated by the utilities' ability to flow through to customers the cost of fuel and purchased power through basic rates and/or the use of rate-stabilization and other mechanisms, as approved by the various regulatory authorities. The ability to flow through to customers the cost of fuel and purchased power alleviates the effect on earnings of the variability in the cost of fuel and purchased power.

There can be no assurance that the current regulator-approved mechanisms allowing for the flow through of the cost of natural gas, fuel and purchased power will continue to exist in the future. An inability of the regulated utilities to flow through the full cost of natural gas, fuel and/or purchased power could materially affect the utilities' results of operations, financial position and cash flows.

Derivative Financial Instruments and Hedging: From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas commodity prices through the use of derivative financial instruments. The derivative financial instruments, such as interest rate swap contracts, foreign exchange future contracts and natural gas commodity swaps and options, are used by the Corporation and its subsidiaries only to manage risk and are not used or held for trading purposes. All derivative financial instruments must be measured at fair value. If a derivative financial instrument is designated as a hedging item in a qualifying cash flow hedging relationship, the effective portion of changes in fair value is recorded in other comprehensive income. Any change in fair value relating to the ineffective portion is recorded immediately in earnings. At the Terasen Gas companies, any difference between the amount recognized upon a change in the fair value of a derivative financial instrument, whether or not in a qualifying hedging relationship, and the amount recovered from customers in current rates is subject to regulatory deferral treatment to be recovered from, or refunded to, customers in future rates.

The Corporation's earnings from, and net investment in, its self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars or in a currency pegged to the US dollar. Belize Electricity's reporting currency is the Belizean dollar while the reporting currency of Caribbean Utilities, FortisUS Energy, BECOL and Fortis Turks and Caicos is the US dollar. The Belizean dollar is pegged to the US dollar at BZ$2.00 = US$1.00. As at December 31, 2009, the Corporation's corporately held US$390 million (December 31, 2008 – US$403 million) long-term debt had been designated as a hedge of a portion of the Corporation's foreign net investments. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately held US dollar borrowings designated as hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the foreign net investments, which are also recorded in other comprehensive income. As at December 31, 2009, the Corporation had approximately US$174 million (December 31, 2008 – US$119 million) in foreign net investments remaining to be hedged.

It is estimated that a 5 cent, or 5 per cent, increase (decrease) in the US dollar-to-Canadian dollar exchange rate from the exchange rate of 1.05, as at December 31, 2009, would increase (decrease) basic earnings per common share of Fortis by 1 cent in 2010.

Management will continue to hedge future exchange rate fluctuations related to the Corporation's foreign net investments and US dollar and Belizean dollar earnings' streams, where possible, through future US dollar borrowings, and will continue to monitor the Corporation's exposure to foreign currency fluctuations on a regular basis.

Interest Rate Risk: Generally, allowed rates of return for regulated utilities in North America are exposed to changes in the general level of long-term interest rates. The allowed rates of return are set either directly through automatic adjustment formulas or indirectly through regulatory determinations of what constitutes an appropriate rate of return on investment. The ROE automatic adjustment formulas tied to long-term Canada bond yields, used in recent years at the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power, have resulted in lower allowed ROEs. Regulatory decisions received in 2009 have reduced the risk of further decreases in allowed ROEs for certain of the Corporation's utilities and other utilities in Canada. In December 2009, the BCUC issued a decision increasing the allowed ROEs at TGI and FortisBC to 9.50 per cent and 9.90 per cent, respectively. The BCUC also determined that the previous ROE automatic adjustment formula will no longer apply and that the allowed ROE as determined in the BCUC decision will apply until reviewed further by the BCUC. In November 2009, the AUC issued its decision on the 2009 Generic Cost of Capital Proceeding. The decision increased the allowed ROE of utilities in Alberta that it regulates, including FortisAlberta, to 9.00 per cent and discontinued the use of the ROE automatic adjustment formula until reviewed further by the AUC. In December 2009, the OEB issued a report reviewing cost of capital for utilities in Ontario. The OEB increased the allowed ROE for utilities in Ontario that it regulates, including FortisOntario, to 9.75 per cent and refined the ROE automatic adjustment formula to reduce sensitivity to changes in long-term Canada bond yields and included an additional factor for utility bond spreads. The National Energy Board ("NEB"), an independent federal agency that regulates several parts of Canada's energy industry, issued a decision in 2009 increasing the regulated total cost of capital of Trans Quebec & Maritimes Inc. ("TQM"), a Canadian regulated natural gas pipeline utility, which effectively established an approximate 100 basis point increase in TQM's allowed ROE for 2008 to 9.70 per cent on a 40 per cent equity ratio. The increase in the total cost of capital and allowed ROE was the result of a change in methodology, which now takes into account financial market information that considers, among other things, changes that have impacted financial markets and economic conditions. In October 2009, the NEB also issued a decision stating that its 1994 multi-pipeline rate of return on equity formula, used to determine the cost of capital for regulated pipeline companies, is no longer in effect, as there is doubt as to the ongoing correctness of using this formula. Instead, cost of capital will be determined by negotiations between the pipelines and their shippers or by the NEB.

The Corporation and its subsidiaries are also exposed to interest rate risk associated with borrowings under credit facilities and floating-rate long-term debt. However, the Terasen Gas companies and FortisBC have regulatory approval to defer any increase or decrease in interest expense resulting from fluctuations in interest rates associated with variable-rate credit facilities for recovery from, or refund to, customers in future rates. As described in the "Business Risk Management – Derivative Financial Instruments and Hedging" section of this MD&A, the Corporation and its subsidiaries may also enter into interest rate swap agreements from time to time to help reduce interest rate risk.

As at December 31, 2009, approximately 81 per cent of the Corporation's consolidated long-term debt and capital lease obligations had maturities beyond five years. With a significant portion of the Corporation's consolidated debt having long-term maturities, interest rate risk on debt refinancing has been reduced for the near and medium terms.

The following table outlines the nature of the Corporation's consolidated debt as at December 31, 2009.

Total Debt

As at December 31, 2009	($ millions)	(%)
Short-term borrowings	**415**	**7.0**
Utilized variable-rate credit facilities classified as long-term	**208**	**3.5**
Variable-rate long-term debt and capital lease obligations (including current portion)	**16**	**0.3**
Fixed-rate long-term debt and capital lease obligations (including current portion)	**5,276**	**89.2**
Total	**5,915**	**100.0**

A change in the level of interest rates could materially affect the measurement and recording of changes in the fair value of interest rate swaps and the measurement and disclosure of the fair value of long-term debt. The impact of a material change in interest rates on the fair value measurement of the interest rate swap outstanding, as at December 31, 2009, is not expected to materially affect the Corporation's consolidated earnings and comprehensive income due to the low notional value of the interest rate swap and its near-term maturity.

The fair value of the interest rate swap and the Corporation's consolidated long-term debt, as at December 31, 2009, is provided in the "Financial Instruments" section of this MD&A. A sensitivity analysis of a change in interest rates, as that change would have affected 2009 financial results, is disclosed in Note 26 to the 2009 Consolidated Financial Statements.

Counterparty Risk: The Terasen Gas companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments. The Terasen Gas companies are also exposed to significant credit risk on physical off-system sales. The Terasen Gas companies deal with high credit-quality institutions in accordance with established credit approval practices. Due to events in the capital markets over the past year, including significant government intervention in the banking system, the Terasen Gas companies have further limited the financial counterparties they transact with and have reduced available credit to, or taken additional security from, the physical off-system sales counterparties with which they transact. The Terasen Gas companies did not experience any counterparty defaults in 2009 and are not expecting any counterparties to fail to meet their obligations. As events over the past year have indicated, however, the credit quality of counterparties can change rapidly.

FortisAlberta is exposed to credit risk associated with sales to retailers. Significantly all of FortisAlberta's distribution-service billings are to a relatively small group of retailers. As required under regulation, FortisAlberta minimizes its credit exposure associated with retailer billings by obtaining from the retailer a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating. See also the "Business Risk Management – Economic Conditions" section of this MD&A.

Competitiveness of Natural Gas: Prior to 2000, natural gas consistently enjoyed a substantial competitive advantage when compared with alternative sources of energy in British Columbia. However, since electricity prices in British Columbia continue to be set based on the historical average cost of production, rather than on market forces, they have remained artificially low compared to market-priced electricity. As a result, the price of electricity for residential customers in British Columbia is now only marginally higher than for natural gas. There is no assurance that natural gas will continue to maintain a competitive price advantage in the future. If natural gas pricing becomes uncompetitive with electricity pricing or pricing for alternative energy sources, the ability of the Terasen Gas companies to add new customers could be impaired and existing customers could reduce their consumption of natural gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. This may result in higher rates and could, in an extreme case, ultimately lead to an inability to fully recover the cost of service of the Terasen Gas companies in rates charged to customers. See also the "Business Risk Management – Risks Related to TGVI" and "Business Risk Management – Government of British Columbia's Energy Plan" sections of this MD&A.

Natural Gas Supply: The Terasen Gas companies are dependent on a limited number of pipeline and storage providers, particularly in the Vancouver, Fraser Valley and Vancouver Island service areas where the majority of the natural gas distribution customers of the Terasen Gas companies are located. Regional market prices have been higher from time to time than prices elsewhere in North America, as a result of insufficient seasonal and peak storage and pipeline capacity to serve the increasing demand for natural gas in British Columbia and the U.S. Pacific Northwest. In addition, the Terasen Gas companies are critically dependent on a single-source transmission pipeline. In the event of a prolonged service disruption of the Spectra Pipeline System, residential customers of the Terasen Gas companies could experience outages, thereby affecting revenue and also resulting in costs to safely relight customers.

Defined Benefit Pension Plan Performance and Funding Requirements: Each of Terasen, FortisAlberta, FortisBC, Newfoundland Power, FortisOntario, Algoma Power, Caribbean Utilities and Fortis maintain defined benefit pension plans for certain of their employees; however, only 60 per cent of the above utilities' total employees are members of such plans.

The Corporation's and subsidiaries' defined benefit pension plans are subject to judgments utilized in the actuarial determination of the accrued pension benefit obligation and related net pension cost. The primary assumptions utilized by management are the expected long-term rate of return on pension plan assets and the discount rate used to value the accrued pension benefit obligation. A discussion of the critical accounting estimates associated with defined benefit pension plans is provided in the "Critical Accounting Estimates – Employee Future Benefits" section of this MD&A.

Pension benefit obligations and related net pension cost can be affected by volatility in the global financial and capital markets. There is no assurance that the pension plan assets will earn the assumed long-term rates of return in the future. With the exception of Newfoundland Power and Terasen, the pension plan assets are valued at fair value. At Newfoundland Power and Terasen, the pension plan assets are valued using the market-related value as disclosed in Note 2 to the 2009 Consolidated Financial Statements. Market-driven changes impacting the performance of the pension plan assets may result in material variations in actual return on pension plan assets from the assumed long-term return on the assets. This may cause material changes in future pension funding requirements from current estimates and material changes in future net pension cost.

Market-driven changes impacting discount rates, which are used to value the accrued pension benefit obligations as at the measurement date of each of the defined benefit pension plans, may result in material changes in future pension funding requirements from current estimates and material changes in future net pension cost.

There is also risk associated with measurement uncertainty inherent in the actuarial valuation process as it affects the measurement of net pension cost, future funding requirements, the accrued benefit asset, accrued benefit liability and benefit obligation.

The above risks are mitigated as any increase or decrease in future pension funding requirements and/or net pension cost at the regulated utilities is expected to be recovered from, or refunded to, customers in future rates, subject to forecast risk. However, at the Terasen Gas companies and FortisBC, and at Newfoundland Power beginning in 2010, actual net pension cost above or below the forecast net pension cost approved for recovery in customer rates for the year is subject to deferral account treatment for recovery from, or refund to, customers in future rates, subject to regulatory approval. Also mitigating the above risks is the fact that the defined benefit pension plans at FortisAlberta and Newfoundland Power are closed to all new employees.

Risks Related to TGVI: TGVI is a franchise under development in the price-competitive service area of Vancouver Island, with a customer base and revenue that is insufficient to meet the Company's current cost of service. To assist with competitive rates during franchise development, the Vancouver Island Natural Gas Pipeline Agreement ("VINGPA") provides royalty revenue from the Government of British Columbia that currently covers approximately 20 per cent of the cost of service. This revenue is due to expire at the end of 2011, after which time TGVI's customers will be required to absorb the full commodity cost of gas, all other costs of service and the recovery of any remaining accumulated revenue deficiencies. When VINGPA expires in 2011, the remaining amount outstanding under non-interest bearing senior government loans, which is currently treated as a reduction of rate base, will be required to be fully repaid. As at December 31, 2009, the balance outstanding under these loans was $53 million. As the debt is repaid, the cost of the higher rate base will increase the cost of service and customer rates, making gas less competitive with electricity on Vancouver Island.

Government of British Columbia's Energy Plan: The Government of British Columbia released its Energy Plan in February 2007. The Energy Plan is a natural progression from the previous plan with consistent principles and a strong focus on environmental leadership, energy conservation and efficiency, and investing in innovation. The Energy Plan outlines various measures to address the challenges of global warming, including that all electricity produced in British Columbia will be required to have zero net greenhouse gas emissions by 2016. The Energy Plan places a significant responsibility on British Columbians to conserve energy by requiring 50 per cent of British Columbia's incremental resource needs to be achieved through conservation by 2020. The Energy Plan emphasizes efficiency by requiring BC Hydro to eliminate electricity imports and become fully self-sufficient by 2016. The Energy Plan also states that 90 per cent of British Columbia's electricity will come from renewable sources and that British Columbia will become the first jurisdiction in North America to require 100 per cent carbon sequestration for any coal-fired electricity project. Many of the principles of the Energy Plan were incorporated into the regulatory framework in British Columbia upon the British Columbia legislature's adoption of the *Utilities Commission Amendment Act, 2008.* In addition, the *Carbon Tax Act, 2008* provides for a consumption tax on carbon-based fuels, which affects the competitiveness of natural gas versus non-carbon-based energy sources. The Act, however, did not introduce a carbon tax on imported electricity generated through the combustion of carbon-based fuels. The future impact of the Government of British Columbia's Energy Plan and the related legislation may have a material impact on the competitiveness of natural gas relative to other energy sources.

Environmental Risks: The Corporation and its subsidiaries are subject to numerous laws, regulations and guidelines governing the generation, management, storage, transportation, recycling and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment. Environmental damage and associated costs could potentially arise due to a variety of events, including the impact of severe weather and natural disasters on facilities and equipment, and equipment failure. Costs arising from environmental protection initiatives, compliance with environmental laws, regulations and guidelines or damages may become material to the Corporation and its subsidiaries. In addition, the process of obtaining environmental regulatory approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive. During 2009, costs arising from environmental protection, compliance or damages were not material to the Corporation's consolidated results of operations, cash flows or financial position. The Corporation believes that it and its subsidiaries are materially compliant with environmental laws, regulations and guidelines applicable to them in the various jurisdictions in which they operate. As at December 31, 2009, there were no material environmental liabilities recorded in the Corporation's 2009 Consolidated Financial Statements and there were no material unrecorded environmental liabilities known to management. The regulated utilities would seek to recover in customer rates the costs associated with environmental protection, compliance or damages; however, there is no assurance that the regulators would agree with the utilities' requests and, therefore, unrecovered costs, if substantial, could materially affect the results of operations, cash flows and financial position of the utilities.

From time to time, it is possible that the Corporation and its subsidiaries may become subject to government orders, investigations, inquiries or other proceedings relating to environmental matters. The occurrence of any of these events, or any changes in applicable environmental laws, regulations and guidelines or their enforcement or regulatory interpretation, could materially impact the results of operations, cash flows and financial position of the Corporation and its subsidiaries.

The Corporation's gas and electricity businesses are subject to inherent risks, including risk of fires and contamination of air, soil or water from hazardous substances. Risks associated with fire damage relate to the extent of forest and grassland cover, habitation and third-party facilities located on or near the land on which the utilities' facilities are situated. The utilities may become liable for fire suppression costs, regeneration and timber value costs and third-party claims in connection with fires on lands on which its facilities are located if it is found that such facilities were the cause of a fire and such claims, if successful, could be material. Risks also include the responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. The risk of contamination of air, soil and water at the electric utilities primarily relates to the storage and handling of large volumes of fuel, the use and/or disposal of petroleum-based products, mainly transformer and lubricating oil, in the utilities' day-to-day operating and maintenance activities, and emissions from the combustion of fuel required in the generation of electricity. The risk of contamination of air, soil or water at the natural gas utilities primarily relates to natural gas and propane leaks and other accidents involving these substances. The management of greenhouse gas emissions is the main environmental concern of the Corporation's regulated gas utilities, primarily due to recent changes to the Government of British Columbia's Energy Plan and related legislation as discussed above. Any changes in environmental laws, regulations or guidelines governing contamination could lead to significant increases in costs to the Corporation and its subsidiaries.

The key environmental hazards related to hydroelectric generation operations include the creation of artificial water flows that may disrupt natural habitats and the storage of large volumes of water for the purpose of electricity generation.

Scientists and public health experts in Canada, the United States and other countries are studying the possibility that exposure to electric and magnetic fields from power lines, household appliances and other electricity sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health hazard, litigation could result and the electric utilities could be required to pay damages and take mitigation measures on its facilities. The costs of litigation, damages awarded and mitigation measures, if not approved by regulators for recovery in customer rates, could materially impact the results of operations, cash flows and financial condition of the electric utilities.

While the Corporation and its subsidiaries maintain insurance, there can be no assurance that all possible types of liabilities that may arise related to environmental matters will be covered by the insurance. For further information on insurance, refer to the "Business Risk Management – Insurance Coverage Risk" section of this MD&A.

As part of their respective environmental management systems, the utilities are continuously establishing and implementing programs and procedures to identify potential environmental impacts, mitigate those impacts and monitor environmental performance.

Insurance Coverage Risk: While the Corporation and its subsidiaries maintain insurance, a significant portion of the Corporation's regulated electric utilities' T&D assets are not covered under insurance, as is customary in North America, as the cost of the coverage is not considered economical. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities that may be incurred by the Corporation and its subsidiaries will be covered by insurance. The Corporation's regulated utilities would likely apply to their respective regulatory authority to recover the loss or liability through increased customer rates. However, there can be no assurance that a regulatory authority would approve any such application in whole or in part. Any major damage to the physical assets of the Corporation and its subsidiaries could result in repair costs and customer claims that are substantial in amount and which could have an adverse effect on the Corporation's and subsidiaries' results of operations, cash flow and financial position. In addition, the occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by the Corporation and its subsidiaries or claims that fall within a significant self-insured retention could have a material adverse effect on the Corporation's and subsidiaries' results of operations, cash flow and financial position.

It is anticipated that such insurance coverage will be maintained. However, there can be no assurance that the Corporation and its subsidiaries will be able to obtain or maintain adequate insurance in the future at rates considered reasonable or that insurance will continue to be available on terms as favourable as the existing arrangements or that the insurance companies will meet their obligations to pay claims.

Licences and Permits: The acquisition, ownership and operation of gas and electric utilities and assets require numerous licences, permits, approvals and certificates from various levels of government and government agencies. The Corporation's regulated utilities and non-regulated generation operations may not be able to obtain or maintain all required regulatory approvals. If there is a delay in obtaining any required regulatory approval, or if there is a failure to obtain or maintain any required approval or to comply with any applicable law, regulation or condition of an approval, the operation of the assets and the sale of gas and electricity could be prevented or become subject to additional costs, any of which could materially affect the subsidiaries.

FortisBC's ability to generate electricity from its facilities on the Kootenay River and to receive its entitlement of capacity and energy under the amended and restated Canal Plant Agreement as of July 1, 2005 depends upon the maintenance of its water licences issued under the *Water Act* (British Columbia). In addition, water flows on the Kootenay River are governed under the terms of the Columbia River Treaty between Canada and the United States. Government authorities in Canada and the United States have the power under the treaty to regulate water flows to protect environmental values in a manner that could adversely affect the amount of water available for the generation of power.

Loss of Service Area: FortisAlberta serves customers residing within various municipalities throughout its service areas. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta located within their municipal boundaries. Upon the termination of its franchise agreement, a municipality has the right, subject to AUC approval, to purchase FortisAlberta's assets within its municipal boundaries pursuant to the *Municipal Government Act* (Alberta). Under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric utility expands its boundaries, it can acquire FortisAlberta's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* (Alberta) provides for compensation, including payment for FortisAlberta's assets on the basis of replacement cost less depreciation. Given the historical growth of Alberta and its municipalities, FortisAlberta may be affected by transactions of this type.

The consequence to FortisAlberta of a municipality purchasing its distribution assets would be an erosion of the Company's rate base, which would reduce the capital upon which FortisAlberta could earn a regulated return. No transactions are currently in progress with FortisAlberta pursuant to the *Municipal Government Act* (Alberta). However, upon expiration of franchise agreements, there is a risk that municipalities will opt to purchase the distribution assets existing within their boundaries, the loss of which could materially affect the results of operations, cash flow and financial position of FortisAlberta.

Market Energy Sales Prices: The Corporation's primary exposure to changes in market energy sales prices had related to its non-regulated energy sales in Ontario, where energy was sold to the Independent Electricity System Operator at market prices. Non-regulated energy sales in Ontario largely related to a power-for-water exchange agreement, known as the Niagara Exchange Agreement, associated with the Rankine hydroelectric generating facility. FortisOntario's water entitlement on the Niagara River expired April 30, 2009 at the end of a 100-year term and, as a result, the Corporation's exposure to market price fluctuations in Ontario has been substantially reduced as earnings related to the Rankine facility have ceased after that date. During 2009, earnings' contribution associated with the Rankine facility was $3.5 million. To a lesser degree, the Corporation is also exposed to changes in energy prices related to energy sales from its non-regulated generation assets in Upper New York State. All energy produced by these assets is sold to the National Grid at market prices. Energy from the Corporation's non-regulated generation assets in Belize, central Newfoundland and British Columbia is sold under medium- and long-term fixed-price contracts.

Transition to International Financial Reporting Standards: Effective January 1, 2011, Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). IFRS will require increased financial statement disclosure and will result in differences in accounting policies between Canadian GAAP and IFRS. The Corporation continues to assess the impact on its future financial reporting of transitioning to IFRS. In July 2009, the IASB issued the Exposure Draft – *Rate-Regulated Activities* ("ED/2009/8") stating that regulatory assets and liabilities arising from activities subject to cost of service regulation would be recognized under IFRS when certain conditions are met. The ability to record regulatory assets and liabilities, as proposed, should reduce earnings' volatility at the Corporation's regulated utilities that may otherwise result under IFRS in the absence of an accounting standard for rate-regulated activities. Conversely, if an accounting standard for rate-regulated activities is not approved or if a standard is approved that is substantially different from that proposed, this could increase volatility in the earnings of the Corporation's regulated utilities. For further information, refer to the "Future Accounting Changes – Transition to IFRS" section of this MD&A.

Changes in Tax Legislation: The Government of Canada has enacted legislative changes that will challenge the continuation of the tax-deferred status of offshore earnings derived from foreign affiliates. The legislative changes will require that the governments of these tax-free jurisdictions enter into tax treaties or other comprehensive tax information-exchange agreements ("TIEAs") with Canada before 2015. If the jurisdictions are unable to establish these tax treaties or TIEAs, the earnings of Canadian subsidiaries operating in these jurisdictions will be taxed on an accrual basis after 2014 as if they were earned in Canada. Conversely, if tax treaties or TIEAs can be reached, the earnings from these jurisdictions will be able to be repatriated to Canada tax-free. In the event that the offshore earnings become taxable, earnings' contribution from Regulated Electric Utilities – Caribbean and BECOL will decrease.

On December 10, 2008, the Advisory Panel on Canada's System of International Taxation (the "Advisory Panel") provided its recommendations to the Minister of Finance of the Government of Canada in its final report, *Enhancing Canada's International Tax Advantage.* The Advisory Panel was formed by the Government of Canada in November 2007 to provide recommendations to improve Canada's international tax policy respecting foreign investment by Canadian businesses and investment in Canada by foreign businesses. The Advisory Panel's recommendations seek to improve Canada's tax system regarding outbound and inbound business investment, non-resident withholding taxes and administration, compliance and legislative processes. Specifically, the Advisory Panel recommended that the Government of Canada pursue TIEAs on a government-to-government basis without resorting to accrual taxation for foreign active business income if TIEAs are not obtained. The Advisory Panel also recommended that the Government of Canada broaden the existing exemption system to cover all foreign active business income earned by foreign affiliates.

Many of the proposals related to foreign affiliate measures, first announced in February 2004, are still in draft form. In the 2009 federal budget documents, the Government of Canada stated that the remaining proposals will be re-evaluated in light of the recommendations of the Advisory Panel before a decision is made on whether and how to proceed with them. On December 18, 2009, the Department of Finance of the Government of Canada released draft legislation, regulations and explanatory notes concerning the foreign affiliate rules under the federal *Income Tax Act*. These measures implement many of the foreign affiliate proposals announced on February 27, 2004.

As of August 31, 2009, the Department of Finance of the Government of Canada reported that it had entered into TIEA negotiations with the Cayman Islands and the Turks and Caicos Islands in June 2009. If agreements can be negotiated, the earnings from Caribbean Utilities and Fortis Turks and Caicos could be repatriated to Canada tax-free. The Corporation is not aware if the Government of Canada has initiated similar negotiations with the Government of Belize.

Any future changes in other tax legislation could also materially affect the Corporation's consolidated earnings.

Information Technology Infrastructure: The ability of the Corporation's utilities to operate effectively is dependent upon developing, managing and maintaining complex information systems and infrastructure that are employed to support the operation of distribution, transmission and generation facilities, provide customers with billing and load settlement information and support the financial and general operating aspects of their business. System failures could have a material adverse effect on the utilities.

First Nations' Lands: The Terasen Gas companies and FortisBC provide service to customers on First Nations' reserves and maintain gas and electric distribution facilities, and electric transmission and generation facilities, on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations' bands and the Government of British Columbia is underway, but the basis upon which settlements might be reached in the service areas of the Terasen Gas companies and FortisBC is not clear. Furthermore, not all First Nations' bands are participating in the process. To date, the policy of the Government of British Columbia has been to endeavour to structure settlements without prejudicing existing rights held by third parties, such as the Terasen Gas companies and FortisBC. However, there can be no certainty that the settlement process will not materially affect the business of the Terasen Gas companies and FortisBC. In addition, FortisAlberta has distribution assets on First Nations' lands with access permits to these lands held by TransAlta Utilities Corporation ("TransAlta"). In order for FortisAlberta to acquire these access permits, both the Department of Indian and Northern Affairs Canada and the individual band councils must grant approval. FortisAlberta may not be able to acquire the access permits from TransAlta and may be unable to negotiate land-use agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to FortisAlberta and, therefore, may have a material effect on the business of FortisAlberta.

Labour Relations: Approximately 58 per cent of the employees of the Corporation's subsidiaries are members of labour unions or associations that have entered into collective bargaining agreements with the subsidiaries. The provisions of such collective bargaining agreements affect the flexibility and efficiency of the businesses carried out by the subsidiaries. The Corporation considers the relationships of its subsidiaries with its labour unions and associations to be satisfactory but there can be no assurance that current relations will continue in future negotiations or that the terms under the present collective bargaining agreements will be renewed. The inability to maintain or renew the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes that are not provided for in approved rate orders at the regulated utilities and which could have a material effect on the results of operations, cash flow and financial position of the utilities.

FortisAlberta's current collective agreement with the United Utility Workers' Association of Canada will expire in December 2010.

The collective agreement governing Maritime Electric's unionized employees represented by the International Brotherhood of Electrical Workers ("IBEW"), Local 1432, expired in December 2008. In February 2010, a new collective agreement, which expires December 31, 2013, was ratified by the union.

Human Resources: The ability of Fortis to deliver service in a cost-effective manner is dependent on the ability of the Corporation's subsidiaries to attract, develop and retain skilled workforces. Like other utilities across Canada and the Caribbean, the Corporation's utilities are faced with demographic challenges relating to trades, technical staff and engineers. The growing size of the Corporation and an increasingly competitive job market present ongoing recruitment challenges. The Corporation's significant consolidated capital expenditure program over the next several years will present challenges in ensuring the Corporation's utilities have the qualified workforce necessary to complete the capital work initiatives.

Changes in Accounting Standards

The nature, and impact on Fortis, of adopting amended or new Canadian Institute of Chartered Accountants ("CICA") accounting standards affecting the accounting for rate-regulated operations, goodwill and intangible assets, and income taxes, effective January 1, 2009, are described in detail in Notes 2, 4, 9, 10 and 19 to the 2009 Consolidated Financial Statements. The most significant impacts of adopting the new standards were: (i) the increase, as at January 1, 2009, in total future income tax liabilities and total future income tax assets of $491 million and $24 million, respectively; an increase in regulatory assets and regulatory liabilities of $535 million and $59 million, respectively; and a combined $9 million net increase in income taxes payable, deferred credits, other assets, utility capital assets and goodwill associated with the reclassification of future income taxes that were previously netted against these respective balance sheet items; and (ii) the reclassification, as at December 31, 2008, of $264 million to intangible assets and related decreases of $262 million to utility capital assets, $1 million to income producing properties and $1 million to other assets, due to the reclassification of the net book value of land, transmission and water rights, computer software costs, franchise costs, customer contracts and other costs.

In 2009, the Corporation also adopted the new Emerging Issues Committee Abstract 173 ("EIC-173"), *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities.* EIC-173 requires that the Corporation's own credit risk and the credit risk of its counterparties be taken into account in determining the fair value of a financial instrument. There was no material effect on the Corporation's 2009 Consolidated Financial Statements as a result of adopting EIC-173.

Effective December 31, 2009, the Corporation adopted amendments to the CICA Handbook Section 3862, *Financial Instruments – Disclosures*, by providing additional disclosures about the fair value measurement of financial instruments and enhanced liquidity risk disclosures in the consolidated financial statements. The amendments establish a hierarchical disclosure framework associated with the level of pricing observability utilized in measuring fair value and are described and disclosed in Notes 2 and 25 to the 2009 Consolidated Financial Statements.

During the first quarter of 2009, Fortis discontinued the consolidation method of accounting for its investment in the Exploits Partnership, due to the Corporation no longer having control over the cash flows and operations of the Exploits Partnership. Refer to the "Critical Accounting Estimates – Contingencies" section of this MD&A for a further discussion of the Exploits Partnership.

Future Accounting Changes

Transition to IFRS

In October 2009, the Accounting Standards Board ("AcSB") issued a third and final Omnibus Exposure Draft confirming that publicly accountable enterprises in Canada will be required to apply IFRS, in full and without modification, beginning January 1, 2011.

The Corporation's expected IFRS transition date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported on the Corporation's opening IFRS balance sheet as at January 1, 2010 and amounts reported by the Corporation for the year ended December 31, 2010.

The Corporation is continuing to assess the financial reporting impacts of adopting IFRS in 2011. While the impact on future financial position and results of operations is not fully determinable at this time, proposals put forth by the IASB in its July 2009 Exposure Draft ED/2009/8, if adopted, should reduce earnings' volatility at the Corporation's regulated utilities that may otherwise result under IFRS in the absence of an accounting standard for rate-regulated activities.

The Corporation does anticipate a change in the manner in which it will measure and recognize the value of its income producing properties under IFRS and a significant increase in disclosure resulting from the adoption of IFRS. The Corporation is identifying and assessing the impact of this change in valuation and additional disclosure requirements, as well as implementing systems changes that will be necessary to compile the required disclosures. Independent expertise has been engaged to assist in the valuation process.

Differences between IFRS and Canadian GAAP, in addition to those referenced further under "Accounting Policy Impacts and Decisions", may continue to be identified based on further detailed analyses by the Corporation, the outcome of a final standard on accounting for rate-regulated activities and other changes in IFRS prior to the Corporation's conversion to IFRS in 2011.

IFRS Conversion Project: The Corporation commenced its IFRS Conversion Project in 2007 when it established a formal project governance structure, which includes the Audit Committee of Fortis, senior management and project teams from each of the subsidiaries of Fortis. Overall project governance, management and support are coordinated by Fortis. An independent external advisor has been engaged to assist in the IFRS Conversion Project. Project progress reports are provided to the Corporation's Audit Committee on a quarterly basis. The Corporation has also engaged its external auditors, Ernst & Young, LLP, to review accounting policy determinations as they are arrived at and agreed upon internally by the Corporation's project team.

The Corporation's IFRS Conversion Project consists of three phases: Scoping and Diagnostics, Analysis and Development, and Implementation and Review.

Phase One: Scoping and Diagnostics, which involved project planning and staffing and identification of differences between current Canadian GAAP and IFRS, was completed in the first half of 2008. The areas of accounting difference of highest potential impact to the Corporation, based on existing IFRS at the time, were identified to include rate-regulated accounting; property, plant and equipment; investment property; provisions and contingent liabilities; employee benefits; impairment of assets; income taxes; business combinations; and initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of International Financial Reporting Standards* ("IFRS 1").

Phase Two: Analysis and Development is substantially complete and has involved detailed diagnostics and evaluation of the financial impacts of various options and alternative methodologies provided for under IFRS; identification and design of operational and financial business processes; initial staff training and audit committee orientation; analysis of IFRS 1 optional exemptions and mandatory exceptions to the general requirement for full retrospective application upon transition; analysis of 2011 IFRS disclosure requirements; and development of required solutions to address identified issues.

Phase Three: Implementation and Review has commenced and involves the execution of changes to information systems and business processes; completion of formal authorization processes to approve recommended accounting policy changes; and further training programs across the Corporation's finance and other affected areas, as necessary. It will culminate in the collection of financial information necessary to compile IFRS-compliant financial statements and reconciliations; embedding of IFRS into the Corporation's business processes; and audit committee approval of IFRS-compliant interim and annual financial statements for 2011.

Accounting for Rate-Regulated Activities under IFRS: IFRS does not currently provide specific guidance with respect to accounting for rate-regulated activities. However, in December 2008, the IASB initiated a project on accounting for rate-regulated activities and whether or not rate-regulated entities could recognize assets and liabilities as a result of rate regulation imposed by a regulatory body.

On July 23, 2009, the IASB issued a proposed standard on accounting for rate-regulated activities, ED/2009/8, together with a request for public comments by November 20, 2009. Approximately 150 comment letters, including a response by Fortis, were received by the IASB. The IASB's project schedule had indicated that a final standard on rate-regulated activities would be released in the second quarter of 2010. Commentary received on the ED/2009/8, and resulting activities now planned by the IASB, creates uncertainty as to if and when a final standard will be released. If a final standard is released, it may not be until late 2011.

Based on ED/2009/8 as it currently exists, regulatory assets and liabilities arising from activities subject to cost of service regulation would be recognized under IFRS, based on the measurement of their expected present value. Subject to finalizing a methodology for estimating expected present value, the ability to record regulatory assets and liabilities, as proposed, should reduce earnings' volatility at the Corporation's regulated utilities that may otherwise result under IFRS in the absence of an accounting standard for rate-regulated activities, but will result in the requirement to provide enhanced balance sheet presentation and note disclosures. Continued uncertainty as to the final outcome of ED/2009/8, and a final standard on accounting for rate-regulated activities under IFRS, has resulted in the Corporation being unable to reasonably estimate and conclude on the impact on the Corporation's future financial position and results of operations with respect to differences, if any, in accounting for rate-regulated activities under IFRS versus Canadian GAAP.

Regulators in the jurisdictions in which the Corporation maintains regulated utility operations have initiated, or are engaged in, consultative processes aimed at addressing issues related to the transition to IFRS. These regulators are also working to define regulatory accounting requirements and respective changes that may be required subsequent to January 1, 2011.

During the second quarter of 2009, the AUC issued Rule 026, which provides both a set of guiding principles and positions on the elements of IFRS that will be adopted for rate-making purposes. FortisAlberta and other utilities in Alberta regulated by the AUC collaborated closely with the AUC in the development of Rule 026. FortisAlberta has made a Rule 026 compliant rate application for 2010 and 2011. A decision by the AUC on FortisAlberta's application is pending.

TGI, FortisBC and other regulated utilities in British Columbia drafted a set of IFRS guidelines for use in regulatory applications being submitted by the utilities to the BCUC, including a fourth quarter 2009 addendum to these guidelines to address ED/2009/8.

TGI and TGVI filed applications with the BCUC for the purpose of setting customer rates for 2010 and 2011. As part of these applications, TGI and TGVI applied for changes in accounting policies that, subject to a final IFRS on rate-regulated activities and review by the external auditors, would be compliant with IFRS where possible. In the fourth quarter of 2009, TGI and TGVI received BCUC approval of NSAs for 2010 and 2011 customer rates. The NSAs include provisions that the 2010 impacts of IFRS be deferred for inclusion in customer rates in 2011.

Included in FortisBC's 2010 Revenue Requirements Application was a discussion of IFRS issues that FortisBC expects to encounter on transition, which are largely the result of the uncertainty surrounding a final IFRS standard on accounting for rate-regulated activities. The BCUC's decision with respect to FortisBC's application includes the recognition of several proposed IFRS deferral accounts. The disposition of these deferral accounts will be revisited in conjunction with FortisBC's 2011 Revenue Requirements Application. FortisBC will also continue to work with the BCUC to identify IFRS transitional issues and to suggest how these issues may be addressed.

Other regulated utility operations of Fortis, including Newfoundland Power, Maritime Electric and FortisOntario, continue to provide their respective regulator with regular updates in relation to their plans for transition to IFRS and the status of ED/2009/8.

Accounting Policy Impacts and Decisions: The Corporation has completed its initial assessment of the impacts of adopting IFRS based on the standards as they currently exist, and has identified the following as having the greatest potential to impact the Corporation's accounting policies, financial reporting and information systems requirements upon conversion to IFRS. Final conclusions cannot be reached at this time with respect to the Corporation's rate-regulated entities pending further certainty as to a final IFRS standard on accounting for rate-regulated activities.

(a) Property, Plant and Equipment

IFRS and Canadian GAAP contain the same basic principles of accounting for property, plant and equipment; however, differences in application do exist. For example, capitalization of directly attributable costs in accordance with IAS 16, *Property, Plant and Equipment* ("IAS 16") may require measurement of an item of property, plant and equipment upon initial recognition to include or exclude certain previously recognized amounts under Canadian GAAP. Specifically, there may be changes in accounting for:

i) the amount of capitalized overheads;
ii) the capitalization of major inspections that were previously expensed under Canadian GAAP;
iii) the capitalization of depreciation for which the future economic benefits of an asset are absorbed in the production of another asset; and
iv) the capitalization of borrowing costs in accordance with IAS 23, *Borrowing Costs.*

However, ED/2009/8 proposes that, in the case of qualifying rate-regulated entities, amounts approved by the regulator for inclusion in the cost of self-constructed property, plant and equipment for rate-making purposes shall also be included in the cost of these assets for financial reporting purposes, even if the entity would not otherwise be permitted to include these costs in the cost of its property, plant and equipment based on the application of IAS 16.

IAS 16 also requires an allocation of the amount initially recognized in respect of an item of property, plant and equipment to its significant parts and the depreciation of each part separately. This method of allocating property, plant and equipment may result in an increase in the number of component parts that are recorded and depreciated separately and, as a result, may affect the calculation of depreciation expense.

Upon transition to IFRS, an entity has the elective option to reset the cost of its property, plant and equipment based on fair value in accordance with the provisions of IFRS 1, and to use either the cost model or the revaluation model to measure its property, plant and equipment subsequent to transition. Upon transition to IFRS on January 1, 2010, the Corporation currently intends to reset the cost of hotel properties owned by its non-regulated subsidiary, Fortis Properties, based on fair value and to use the cost model to measure all of Fortis Properties' property, plant and equipment subsequent to transition (excluding those assets to be reclassified as investment property under IFRS, as discussed below under "Investment Property").

ED/2009/8 proposes a new transitional exemption for qualifying rate-regulated entities that will allow them to use, as of the date of transition, the carrying amount of property, plant and equipment under Canadian GAAP as the deemed cost under IFRS. The Corporation's rate-regulated utilities will likely avail of this transitional exemption should it be approved by the IASB as proposed.

The final extent of the impact of applying IAS 16 by the Corporation's rate-regulated utilities, and elective options with respect to accounting for their property, plant and equipment upon transition to IFRS, cannot be made at this time pending further certainty as to a final standard on accounting for rate-regulated activities.

(b) Investment Property

IAS 40, *Investment Property* ("IAS 40") defines investment property as land or buildings held to earn rental income, for capital appreciation or both. The Corporation's real estate assets, which are currently owned by its non-regulated subsidiary, Fortis Properties, and recorded as property, plant and equipment under Canadian GAAP, will be reclassified as investment property under IFRS.

IAS 40 and IFRS 1 provide the Corporation with an elective option to reset the cost of investment property based on fair value at the date of transition. IAS 40 provides further options for measuring investment property subsequent to initial recognition using either the cost or the fair value model. Currently, Fortis Properties intends to reset the cost of its investment property upon transition to IFRS based on fair value as at January 1, 2010 and to use the fair value model to measure its investment property subsequent to transition. Use of the fair value model under IAS 40 means that the Corporation will not recognize depreciation expense with respect to its investment properties in its statement of earnings under IFRS and that any change in the fair value of its investment properties subsequent to initial recognition will be recognized in earnings in the period when the change occurs.

(c) Provisions and Contingent Liabilities

IAS 37, *Provisions, Contingent Liabilities and Contingent Assets* ("IAS 37") requires a provision to be recognized when: (i) there is a present obligation as a result of a past transaction or event; (ii) it is probable that an outflow of resources will be required to settle the obligation; and (iii) a reliable estimate can be made of the obligation. The threshold for recognizing a provision under Canadian GAAP is higher than under IFRS. It is possible, therefore, that some contingent liabilities which would not have been recognized under Canadian GAAP may meet the criteria for recognition as a provision under IFRS.

In January 2010, the IASB published an Exposure Draft – *Measurement of Liabilities in IAS 37* ("ED/2010/1"). The publication of ED/2010/1 is part of a larger IASB project, which has been ongoing since 2005 and which is intended to result in a new IFRS to replace IAS 37. ED/2010/1 is open for public comment until April 12, 2010. Based on comments received on ED/2010/1, and previous tentative decisions by the IASB with respect to other aspects of IAS 37, a final IFRS to replace IAS 37 is planned for release in the third quarter of 2010.

(d) Employee Benefits

IAS 19, *Employee Benefits* ("IAS 19") requires past service costs associated with defined benefit plans to be expensed on an accelerated basis with vested past service costs to be expensed immediately and unvested past service costs to be expensed on a straight-line basis until the benefits become vested. In addition, actuarial gains and losses are permitted to be recognized directly in equity rather than through earnings, and IFRS 1 also provides an option to recognize immediately in retained earnings all cumulative actuarial gains and losses existing as at the date of transition to IFRS.

Under Canadian GAAP, past service costs are generally amortized on a straight-line basis over the expected average remaining service period of active employees in the defined benefit plan.

The Corporation and its subsidiaries maintain a number of defined benefit pension plans and supplementary and other post-employment benefit plans, which will be subject to different accounting treatment under IFRS versus Canadian GAAP. However, the full extent of the impact of applying IAS 19 by the Corporation and its subsidiaries cannot be made at this time, pending further certainty as to a final standard on accounting for rate-regulated activities.

(e) Impairment of Assets

IAS 36, *Impairment of Assets* ("IAS 36") uses a one-step approach for testing and measuring asset impairments, with asset carrying values being compared to the higher of value in use and fair value less costs to sell. Value in use is defined as being equal to the present value of future cash flows expected to be derived from the asset in its current state. In the absence of an active market, fair value less costs to sell may also be determined using discounted cash flows. The use of discounted cash flows under IFRS to test and measure asset impairment differs from Canadian GAAP where undiscounted future cash flows are used to compare against the asset's carrying value to determine if impairment exists. This may result in more frequent write-downs in the carrying value of assets under IFRS since asset carrying values that were previously supported under Canadian GAAP based on undiscounted cash flows may not be supported on a discounted cash flow basis under IFRS. However, under IAS 36, previous impairment losses may be reversed where circumstances change such that the impairment has been reduced. This also differs from Canadian GAAP, which prohibits the reversal of previously recognized impairment losses.

As the majority of the Corporation's assets are owned by utility subsidiaries that are rate regulated, the potential for and extent of any impairment losses will be primarily subject to the continued ability of the utilities to recover costs through the regulatory process.

As stated above, the Corporation intends to reset the cost of investment property owned by its non-regulated subsidiary, Fortis Properties, upon transition to IFRS based on fair value as at January 1, 2010 and to use the fair value model to measure its investment property subsequent to transition. Changes in the fair value of the Corporation's investment property each period will, therefore, be reflected under IFRS in the statement of earnings.

The Corporation's other non-regulated assets will be subject to the one-step approach under IFRS for testing and measuring asset impairments, which may result in some impairments being recognized or reversed under IFRS that would not have been required or permitted under Canadian GAAP.

The Corporation is continuing to assess the impact of adopting IAS 36. Currently, however, Fortis does not expect to incur any material asset impairments upon transition to IFRS.

(f) Income Taxes

IAS 12, *Income Taxes* ("IAS 12") prescribes that an entity account for the tax consequences of transactions and other events in the same way that it accounts for the transactions and other events themselves. Therefore, where transactions and other events are recognized in earnings, the recognition of deferred tax assets or liabilities that arise from those transactions should also be recorded in earnings. For transactions that are recognized outside the statement of earnings, either in other comprehensive income or directly in equity, any related tax effects should also be recognized outside the statement of earnings.

The most significant impact of IAS 12 on the Corporation will be derived directly from the accounting policy decisions made under IAS 16 and IAS 40. In addition, the Corporation's rate-regulated utilities currently account for income taxes based on regulatory decisions. Therefore, the impact on the Corporation of accounting for the tax consequences of transactions and other events under IFRS versus Canadian GAAP cannot be fully determined at this time pending further certainty as to a final IFRS standard on accounting for rate-regulated activities.

(g) Business Combinations

Under IFRS 3, *Business Combinations* ("IFRS 3"), business combinations must be accounted for by applying the acquisition method. One of the parties to a business combination can always be identified as the acquirer, being the entity that obtains control of the other business. Control is defined as the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. Fortis, as an acquirer, shall identify the date on which it obtains control of an acquiree. This date is usually the closing date of the acquisition, which would generally be the date on which the Corporation legally transfers the consideration or acquires the assets and assumes the liabilities of the acquiree. As of the date on which it obtains control, Fortis shall recognize, separately from goodwill, the identifiable assets acquired, the liabilities assumed and any non-controlling interest in the acquiree in accordance with IFRS 3.

In accordance with IFRS 3, acquisition-related costs incurred to effect a business combination shall be expensed in the period the costs are incurred. Under IFRS, these costs are not permitted to form a component of goodwill as is permitted under Canadian GAAP.

Under IFRS 1, an entity has the option to retroactively apply IFRS 3 to all business combinations or may elect to apply the standard prospectively only to those business combinations that occur after the date of transition. The Corporation currently intends to avail of the elective exemption under IFRS 1, which removes the requirement to retrospectively restate any business combinations prior to the date of transition to IFRS, subject to certain balance sheet adjustments that may be required by FortisAlberta with respect to goodwill it had recorded based on its previous owner's application of pushdown accounting under Canadian GAAP. These balance sheet adjustments by FortisAlberta are not expected to have an impact on the Corporation's consolidated financial position upon transition to IFRS.

The AcSB recently issued new CICA Handbook Section 1582, *Business Combinations* and Section 1602, *Non-Controlling Interests.* The effective date of these sections is fiscal years beginning on or after January 1, 2011; however, early adoption is permitted. The Corporation expects to apply these new Handbook sections prospectively to any business combinations that occur on or after January 1, 2010. These new Handbook sections are substantially aligned with the accounting for business combinations and non-controlling interests under IFRS 3. Further information related to the above two new Canadian standards is provided under the heading "Future Accounting Changes – Business Combinations".

(h) IFRS 1, First-Time Adoption of IFRS

IFRS 1 provides the framework for the first-time adoption of IFRS and specifies that, in general, an entity shall apply the principles under IFRS retrospectively. IFRS 1 also specifies that the adjustments that arise on retrospective conversion to IFRS from other GAAP should be recognized directly in retained earnings. Certain optional exemptions and mandatory exceptions to retrospective application are provided for under IFRS 1.

The Corporation has completed an analysis of IFRS 1. While preliminary decisions have been made with respect to the elective exemptions available upon transition, final decisions cannot be made at this time pending further certainty as to a final IFRS standard on accounting for rate-regulated activities.

(i) Internal Controls over Financial Reporting and Disclosure

In accordance with the Corporation's approach to certification of internal controls required under Canadian Securities Administrators' National Instrument 52-109, all entity-level, information technology, disclosure and business process controls will require updating and testing to reflect changes arising from the Corporation's conversion to IFRS. Where material changes are identified, these changes will be mapped and tested to ensure that no material control deficiencies exist as a result of the Corporation's conversion to IFRS.

(j) Information Systems

It is anticipated that the adoption of IFRS will have some impact on information systems requirements. The Corporation and its subsidiaries have assessed the need for systems upgrades or modifications to ensure an efficient conversion to IFRS. As part of Phase Two of the Corporation's IFRS Conversion Project, information systems plans have been prepared for implementation in Phase Three. The extent of the impact on information systems is largely dependent upon certainty as to a final IFRS standard on accounting for rate-regulated activities.

The IASB has a number of ongoing projects on its agenda, in addition to the project on accounting for rate-regulated activities, that may result in changes to existing IFRS prior to the Corporation's conversion to IFRS in 2011. The Corporation continues to monitor these projects and the impact that any resulting IFRS changes may have on its accounting policies, financial position or results of operations under IFRS for 2011 and beyond.

Business Combinations

In January 2009, the AcSB issued new CICA Handbook Section 1582, *Business Combinations*, together with Section 1601, *Consolidated Financial Statements* and Section 1602, *Non-Controlling Interests*. These new standards are effective for fiscal years beginning on or after January 1, 2011 with early adoption permitted. The Corporation has chosen to early adopt the above standards as at January 1, 2010. As a result of adopting Section 1582, changes in the determination of the fair value of the assets and liabilities of the acquiree will result in a different calculation of goodwill with respect to future acquisitions. Such changes include the expensing of acquisition-related costs incurred during a business acquisition, rather than recording them as a capital transaction, and the disallowance of recording restructuring accruals by the acquirer. The adoption of Section 1582 will affect the recognition of business combinations completed by the Corporation on or after January 1, 2010 and, as a result, may have a material impact on the Corporation's consolidated earnings and financial position.

Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The adoption of Sections 1601 and 1602 will result in non-controlling interests being presented as components of equity, rather than as liabilities, on the consolidated balance sheet. Also, net earnings and components of other comprehensive income attributable to the owners of the parent and to the non-controlling interests are required to be separately disclosed on the statement of earnings. The adoption of Sections 1601 and 1602 is not expected to have a material impact on the Corporation's consolidated earnings, cash flows or financial position.

Financial Instruments

The carrying values of financial instruments included in current assets, current liabilities, other assets and deferred credits in the consolidated balance sheets of Fortis approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments. The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a market credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle the long-term debt prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs. The fair value of the Corporation's preference shares is determined using quoted market prices.

A decrease in credit risk and spreads, as a result of the improvement in and decreased volatility experienced in the financial and capital markets in the latter part of 2009, has resulted in a higher fair value relative to carrying value for the Corporation's consolidated long-term debt and preference shares as at December 31, 2009 compared to December 31, 2008.

The carrying and fair values of the Corporation's consolidated long-term debt and preference shares as at December 31 were as follows.

Financial Instruments

As at December 31	**2009**		2008	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt, including current portion[(1)]	**5,502**	**5,906**	5,122	5,040
Preference shares, classified as debt[(2)]	**320**	**348**	320	329

[(1)] Carrying value as at December 31, 2009 excludes unamortized deferred financing costs of $39 million (December 31, 2008 – $34 million) and capital lease obligations of $37 million (December 31, 2008 – $36 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 $347 million preference shares classified as equity was $356 million as at December 31, 2009 (December 31, 2008 – carrying value of $347 million; fair value of $268 million).

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

The following table summarizes the valuation of the Corporation's derivative financial instruments as at December 31.

Derivative Financial Instruments

As at December 31	**2009**				2008	
Asset (Liability)	**Term to Maturity** *(years)*	**Number of Contracts**	**Carrying Value** *($ millions)*	**Estimated Fair Value** *($ millions)*	Carrying Value *($ millions)*	Estimated Fair Value *($ millions)*
Interest rate swaps	**1**	**1**	**–**	**–**	–	–
Foreign exchange forward contract	**< 2**	**1**	**–**	**–**	7	7
Natural gas derivatives:						
Swaps and options	**Up to 5**	**223**	**(119)**	**(119)**	(84)	(84)
Gas purchase contract premiums	**Up to 2**	**69**	**(3)**	**(3)**	(8)	(8)

The interest rate swap is held by Fortis Properties and is designated as a hedge of the cash flow risk related to floating-rate long-term debt and matures in October 2010. The effective portion of the change in the fair value of the interest rate swap at Fortis Properties is recorded in other comprehensive income. During 2009, another interest rate swap held by Fortis Properties matured.

The foreign exchange forward contract is held by TGVI and hedges the cash flow risk related to approximately US$15 million remaining to be paid under a contract for the construction of an LNG storage facility.

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

The changes in the fair values of the foreign exchange forward contract 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 value of the foreign exchange forward contract was recorded in accounts receivable as at December 31, 2009 and 2008. The fair value of the natural gas derivatives was recorded in accounts payable as at December 31, 2009 and 2008.

The interest rate swap is valued at the present value of future cash flows based on published forward future interest rate curves. 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 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 values of the foreign exchange forward contract and the natural gas derivatives are estimates of the amounts the Terasen Gas companies would have to receive or pay if forced to settle all outstanding contracts as at the balance sheet date.

The fair value of the Corporation's financial instruments, including derivatives, reflects a point-in-time estimate 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 earnings or cash flows.

Critical Accounting Estimates

The preparation of the Corporation's 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 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.

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. The Corporation's critical accounting estimates are discussed below.

Regulation: Generally, the accounting policies of the Corporation's regulated utilities are subject to examination and approval by the respective regulatory authority. These accounting policies may differ from those used by entities not subject to rate regulation. 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 entities not subject to rate regulation. Regulatory assets and regulatory liabilities arise as a result of the rate-setting process at the regulated utilities and have been recorded based on previous, existing or expected regulatory orders or decisions. Certain estimates are necessary since the regulatory environments in which the Corporation's regulated utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the regulatory authorities for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are reported in earnings in the period in which they become known. As at December 31, 2009, Fortis recorded $981 million in current and long-term regulatory assets (December 31, 2008 – $360 million) and $489 million in current and long-term regulatory liabilities (December 31, 2008 – $434 million). The increase in regulatory assets and liabilities year over year reflected the recording of regulatory assets and liabilities, effective January 1, 2009, associated with the recognition of future income taxes upon adoption of amended accounting standards pertaining to income taxes. The nature of the Corporation's regulatory assets and liabilities is described in Note 4 to the 2009 Consolidated Financial Statements.

Capital Asset Amortization: Amortization, by its nature, is an estimate based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2009, the Corporation's consolidated utility capital assets, income producing properties and intangibles were approximately $8.5 billion, or approximately 70 per cent of total consolidated assets, compared to consolidated utility capital assets, income producing properties and intangibles of approximately $8.0 billion, or approximately 71 per cent of total consolidated assets, as at December 31, 2008. The increase in capital assets was primarily associated with capital expenditures, which totalled more than $1 billion in 2009. Amortization expense for 2009 was $364 million compared to $348 million for 2008. Changes in amortization rates may have a significant impact on the Corporation's consolidated amortization expense.

As part of the customer rate-setting process at the Corporation's regulated utilities, appropriate amortization rates are approved by the respective regulatory authority. As required by the respective regulator, amortization rates at FortisAlberta, Newfoundland Power and Maritime Electric include an amount for regulatory purposes to provide for future asset removal and site restoration costs, net of salvage proceeds, over the life of the assets. Actual asset removal and site restoration costs, net of salvage proceeds, are recorded against the provision when incurred. The accrual of the estimated costs is included with amortization expense and the provision balance is recorded as a long-term regulatory liability. The estimate of the future asset removal and site restoration costs, net of salvage proceeds, is based on historical experience and future expected cost trends. The balance of this regulatory liability as at December 31, 2009 was $326 million (December 31, 2008 – $325 million). The amount of future asset removal and site restoration costs provided for and reported in amortization expense during 2009 was $29 million (2008 – $27 million).

The amortization periods used and the associated rates are reviewed on an ongoing basis to ensure they continue to be appropriate. From time to time, third-party depreciation studies are performed at the regulated utilities. Based on the results of these depreciation studies, the impact of any over or under amortization, as a result of actual experience differing from that expected and provided for in previous amortization rates, is generally reflected in future amortization rates and amortization expense, when the differences are refunded or collected in customer rates as approved by the regulator. During the fourth quarter of 2009, Fortis Turks and Caicos completed a depreciation study. The impact was a change in depreciation estimates resulting in a favourable adjustment of approximately $1.5 million to amortization expense in the fourth quarter.

Income Taxes: Income taxes are determined based on estimates of the Corporation's current income taxes and estimates of future income taxes resulting from temporary differences between the carrying values of assets and liabilities in the consolidated financial statements and their tax values. The use of estimation with respect to recording future income taxes has increased due to the adoption by the Corporation of amended CICA Handbook Section 3465, *Income Taxes*, effective January 1, 2009. A future income tax asset or liability is determined for each temporary difference based on the future tax rates that are expected to be in effect and management's assumptions regarding the expected timing of the reversal of such temporary differences. Future income tax assets are assessed for the likelihood that they will be recovered from future taxable income. To the extent recovery is not considered more likely than not, a valuation allowance is recorded and charged against earnings in the period that the allowance is created or revised. Estimates of the provision for income taxes, future income tax assets and liabilities, and any related valuation allowance might vary from actual amounts incurred.

Goodwill Impairment Assessments: Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost, less any previous amortization and write-down for impairment. The Corporation is required to perform an annual impairment test and at such time any event occurs, or if circumstances change, that would indicate that the fair value of a reporting unit was below its carrying value. During 2009, Fortis changed the date of the annual goodwill impairment test from July 31 to October 1 to better correspond with the timing of the preparation of the Corporation's and subsidiaries' annual financial budgets. Accordingly, this accounting change is preferable in the Corporation's circumstance. The change in timing of the test did not delay, accelerate or avoid any impairment charge. The Corporation performed the annual goodwill impairment test as at July 31, 2009 and again as at October 1, 2009. The change in the timing of the impairment test had no impact on the 2009 Consolidated Financial Statements.

To assess for impairment, the fair value of each of the Corporation's reporting units is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and then by comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value of the goodwill is the impairment amount. Fair market value is determined using net present value financial models and management's assumption of future profitability of the reporting units. There was no impairment provision required on approximately $1.6 billion of goodwill recorded on the Corporation's balance sheet as at December 31, 2009.

Employee Future Benefits: The Corporation's and subsidiaries' defined benefit pension plans and other post-employment benefit ("OPEB") plans are subject to judgments utilized in the actuarial determination of the net benefit cost and related obligation. The main assumptions utilized by management in determining the net benefit cost and obligations are the discount rate for the accrued benefit obligation and the expected long-term rate of return on plan assets.

The assumed long-term rates of return on the defined benefit pension plan assets, for the purpose of estimating net pension cost for 2010, are 7 per cent for the larger defined benefit pension plans. This rate compares to assumed long-term rates of return used in 2009 that ranged from 7.00 per cent to 7.25 per cent. The defined benefit pension plan assets experienced total positive returns during 2009 of approximately $71 million compared to expected positive returns of $46 million. The assumed expected long-term rates of return on pension plan assets fall within the range of expected returns as provided by the actuaries' internal models.

The assumed discount rates used to measure the accrued pension benefit obligations on the applicable measurement dates in 2009 and to determine net pension cost for 2010 range from 5.75 per cent to 6.50 per cent for the larger defined benefit plans. These rates compare to assumed discount rates used to measure the accrued pension benefit obligations in 2008 and determine net pension cost for 2009 that ranged from 6.00 per cent to 7.50 per cent. The discount rates decreased, driven mainly by lower credit risk spreads on investment-grade corporate bonds. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments. The methodology in determining the discount rates was consistent with that used to determine the discount rates in the previous year.

The discount rates and fair value of the assets for the defined benefit pension plans at FortisAlberta, FortisBC, FortisOntario and Algoma Power are as of a September 30, 2009 measurement date and thus would not reflect the impact of any changes in capital market conditions to the end of 2009.

There was no material increase in consolidated defined benefit net pension cost for 2009 compared to 2008. For 2009, the amortization of 2008 losses associated with the pension plan assets was largely offset by the impact of higher assumed discount rates for calculating net pension cost in 2009 compared to 2008. Consolidated defined benefit net pension cost for 2009 was also not materially impacted by the outcome of actuarial valuations completed in the first quarter of 2009, as described in the "Liquidity and Capital Resources – Pension Funding" section of this MD&A.

Consolidated defined benefit net pension cost for 2010 is expected to be higher than for 2009, driven mainly by decreases in discount rates assumed in the measurement of the pension obligations, for the reason described above, and the amortization of net actuarial losses that arose in prior years.

The following table provides the sensitivities associated with a 100 basis point move in the expected long-term rate of return on pension plan assets and the discount rate on 2009 defined benefit net pension cost, and the related accrued defined benefit pension asset and liability recorded in the Corporation's consolidated financial statements, as well as the impact on the accrued defined benefit pension obligation. The sensitivity analysis applies to the Corporation's Regulated Gas Utilities and Regulated Electric Utilities.

Sensitivity Analysis of Changes in Rate of Return on Plan Assets and Discount Rate

Year Ended December 31, 2009

Increase (decrease)	**Net pension benefit cost**		**Accrued benefit asset**		**Accrued benefit liability**		**Benefit obligation**	
($ millions)	**Regulated Gas Utilities**	**Regulated Electric Utilities**	**Regulated Gas Utilities**	**Regulated Electric Utilities**	**Regulated Gas Utilities**	**Regulated Electric Utilities**	**Regulated Gas Utilities**	**Regulated Electric Utilities**
Impact of increasing the rate of return assumption by 100 basis points	(3)	(4)	3	4	–	–	–	–
Impact of decreasing the rate of return assumption by 100 basis points	3	4	(3)	(4)	–	–	–	–
Impact of increasing the discount rate assumption by 100 basis points	(1)	(2)	–	2	(1)	–	(27)	(46)
Impact of decreasing the discount rate assumption by 100 basis points	1	5	–	(4)	1	–	33	53

Other assumptions applied in measuring defined benefit net pension cost and/or the accrued pension benefit obligation were the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates.

The OPEB plans of the Corporation and its subsidiaries are also subject to judgments utilized in the actuarial determination of the cost and related obligation. The assumptions described above, except for the assumptions of the expected long-term rate of return on pension plan assets and average rate of compensation increase, along with health care cost trends, were also utilized by management in determining OPEB plan cost and obligations.

As approved by the respective regulator, FortisAlberta and Newfoundland Power record the cost of defined benefit pension and/or OPEB plan benefits on a cash basis, whereby differences between the cash payments made during the year and the cost incurred during the year are deferred as a regulatory asset or regulatory liability. Therefore, changes in assumptions cause changes in regulatory assets and liabilities for these companies and do not affect earnings. As disclosed in the "Business Risk Management – Defined Benefit Pension Plan Performance and Funding Requirements" section of this MD&A, the Terasen Gas companies, FortisBC, and Newfoundland Power beginning in 2010, have regulator-approved mechanisms to defer variations in net pension cost from forecast net pension cost, used to set customer rates, as a regulatory asset or regulatory liability.

As at December 31, 2009, the Corporation had a consolidated accrued benefit asset of $146 million (December 31, 2008 – $133 million) and a consolidated accrued benefit liability of $186 million (December 31, 2008 – $168 million). During 2009, the Corporation recorded a consolidated net benefit cost of $26 million (2008 – $27 million) for all defined benefit and OPEB plans.

Asset-Retirement Obligations: The measurement of the fair value of asset-retirement obligations ("AROs") requires making reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset-retirement costs. While the Corporation has AROs associated with hydroelectric generating facilities, interconnection facilities, wholesale energy supply agreements, removal of certain distribution system assets from rights-of-way at the end of the life of the systems and the remediation of certain land, there were no amounts recorded as at December 31, 2009 and 2008. The nature, amount and timing of costs associated with land and environmental remediation and/or removal of assets cannot be reasonably estimated at this time as the hydroelectric generation and distribution and transmission assets are reasonably expected to operate in perpetuity due to the nature of their operation; applicable licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and ensure the continued provision of service to customers; a land-lease agreement is expected to be renewed indefinitely; and the exact nature and amount of land remediation is indeterminable. In the event that environmental issues are known and identified, assets are decommissioned or the applicable licences, permits, agreements or leases are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

Revenue Recognition: All of the Corporation's regulated utilities, except for Belize Electricity, recognize revenue on an accrual basis. As required by the PUC, Belize Electricity recognizes electricity revenue on a billed basis. Recording revenue on an accrual basis requires use of estimates and assumptions. Customer bills are issued throughout the month based on meter readings that establish gas and electricity consumption by customers since the last meter reading. The unbilled revenue accrual for the period is based on estimated gas and electricity sales to customers for the period since the last meter reading at the rates approved by the respective regulatory authority. The development of the gas and electricity sales estimates generally requires analysis of consumption on a historical basis in relation to key inputs such as the current price of gas and electricity, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled gas and electricity consumption will result in adjustments of gas and electricity revenue in the periods they become known when actual results differ from the estimates. As at December 31, 2009, the amount of accrued unbilled revenue recorded in accounts receivable was approximately $294 million (December 31, 2008 – $365 million) on annual consolidated revenue of approximately $3.6 billion (2008 – $3.9 billion).

Capitalized Overhead: As required by their respective regulator, the Terasen Gas companies, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity, Fortis Turks and Caicos and, commencing in May 2008, Caribbean Utilities capitalize overhead costs which are not directly attributable to specific capital assets but relate to the overall capital expenditure program. These general expenses capitalized ("GEC") are allocated to constructed capital assets and amortized over their estimated service lives. The methodology for calculating and allocating these general expenses to utility capital assets is established by the respective regulator. In 2009, GEC totalled $57 million (2008 – $57 million). Any change in the methodology of calculating and allocating general overhead costs to utility capital assets could have a material impact on the amount recorded as operating expenses versus utility capital assets.

Contingencies: The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with the ordinary course of 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.

The following describes the nature of the Corporation's contingent liabilities.

Terasen

On March 26, 2007, the Minister of Small Business and Revenue and Minister Responsible for Regulatory Reform (the "Minister") in British Columbia issued a decision in respect of the appeal by TGI of an assessment of additional British Columbia Social Service Tax in the amount of approximately $37 million associated with the Southern Crossing Pipeline, which was completed in 2000. The Minister reduced the assessment to $7 million, including interest, which has been paid in full to avoid accruing further interest and recorded as a long-term regulatory deferral asset. TGI was successful in its appeal to the Supreme Court of British Columbia in June 2009. The Province of British Columbia has been granted leave to appeal the decision to the British Columbia Court of Appeal.

During 2007 and 2008, a non-regulated subsidiary of Terasen received Notices of Assessment from Canada Revenue Agency ("CRA") for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the 2009 Consolidated Financial Statements. Terasen has begun the appeal process associated with the assessments.

On July 16, 2009, Terasen was named, along with other defendants, in an action related to damages to property and chattels, including contamination to sewer lines and costs associated with remediation, related to a pipeline rupture in July 2007. Terasen has filed a statement of defence but the claim is in its early stages and the amount and outcome of it is indeterminable at this time and, accordingly, no amount has been accrued in the 2009 Consolidated Financial Statements.

In 2008, the Vancouver Island Gas Joint Venture ("VIGJV") commenced a lawsuit against TGVI seeking damages for alleged overpayments of past tolls and declarations for reduction of its future tolls. The Statement of Claim did not quantify damages and the case did not reach the stage where either party formally quantified VIGJV's claims. In December 2009, VIGJV abandoned its claim and in January 2010, the lawsuit was dismissed by consent dismissal order. The matter is now fully concluded.

FortisBC

The British Columbia Ministry of Forests has alleged breaches of the Forest Practices Code and negligence relating to a fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC. In addition, the Company has been served with a filed writ and statement of claim by private landowners in relation to the same matter. The Company is communicating with its insurers and has filed a statement of defence in relation to both of the actions. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the 2009 Consolidated Financial Statements.

Maritime Electric

In April 2006, CRA reassessed Maritime Electric's 1997–2004 taxation years. The reassessment encompasses the Company's tax treatment, specifically the Company's timing of deductions, with respect to: (i) the ECAM in the 2001–2004 taxation years; (ii) customer rebate adjustments in the 2001–2003 taxation years; and (iii) the Company's payment of approximately $6 million on January 2, 2001 associated with a settlement with NB Power regarding its $450 million write-down of Point Lepreau in 1998. Maritime Electric believes it has reported its tax position appropriately in all respects and has filed a Notice of Objection with the Chief of Appeals at CRA. In December 2008, the Appeals Division of CRA issued a Notice of Confirmation, which confirmed the April 2006 reassessments. In March 2009, the Company filed an Appeal to the Tax Court of Canada.

Should Maritime Electric be unsuccessful in defending all aspects of the reassessment, the Company would be required to pay approximately $14 million in taxes and accrued interest. As at December 31, 2009, Maritime Electric has provided for this amount through future and current income taxes payable. The provisions of the *Income Tax Act* (Canada) require the Company to deposit one-half of the assessment under objection with CRA. The amount currently on deposit with CRA arising from the reassessment is approximately $6 million.

Exploits Partnership

The Exploits Partnership is owned 51 per cent by Fortis Properties and 49 per cent by Abitibi. The Exploits Partnership operated two non-regulated hydroelectric generation plants in central Newfoundland with a combined capacity of approximately 36 MW. In December 2008, the Government of Newfoundland and Labrador expropriated Abitibi's hydroelectric assets and water rights in Newfoundland, including those of the Exploits Partnership. The newsprint mill in Grand Falls-Windsor closed on February 12, 2009, subsequent to which the day-to-day operations of the Exploits Partnership's hydroelectric generating facilities were assumed by Nalcor Energy, a Crown corporation, as an agent for the Government of Newfoundland and Labrador with respect to expropriation matters. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi in the province. The loss of control over cash flows and operations has required Fortis to cease consolidation of the Exploits Partnership, effective February 12, 2009. Discussions between Fortis Properties and Nalcor Energy with respect to expropriation matters are ongoing.

Selected Annual Financial Information

The following table sets forth the annual financial information for the years ended December 31, 2009, 2008 and 2007. The financial information has been prepared in Canadian dollars and 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.

Selected Annual Financial Information

Years Ended December 31 *($ millions, except per share amounts)*	**2009**	2008	2007[(1)]
Revenue	**3,637**	3,903	2,718
Net earnings	**280**	259	199
Net earnings applicable to common shares	**262**	245	193
Total assets	**12,160**	11,166	10,282
Long-term debt and capital lease obligations (excluding current portion)	**5,276**	4,884	4,623
Preference shares[(2)]	**667**	667	442
Common shareholders' equity	**3,193**	3,046	2,601
Basic earnings per common share	**1.54**	1.56	1.40
Diluted earnings per common share	**1.51**	1.52	1.32
Dividends declared per common share	**0.78**	1.01	0.88
Dividends declared per First Preference Share, Series C	**1.3625**	1.3625	1.3625
Dividends declared per First Preference Share, Series E	**1.2250**	1.2250	1.2250
Dividends declared per First Preference Share, Series F	**1.2250**	1.2250	1.2250
Dividends declared per First Preference Share, Series G[(3)]	**1.3125**	1.0184	–

(1) Financial results for 2007 include the financial results of Terasen from May 17, 2007, the date of acquisition by Fortis.

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

(3) A total of 9.2 million First Preference Shares, Series G were issued on May 23, 2008 and June 4, 2008 at $25.00 per share for net after-tax proceeds of $225 million, and which are entitled to receive cumulative dividends in the amount of $1.3125 per share per annum.

2009/2008: Revenue decreased $266 million, or 6.8 per cent, over 2008. The decrease was driven by the flow through to customers of lower natural gas commodity and energy supply costs, combined with the loss of revenue subsequent to the expiration of the Rankine water rights in Ontario in April 2009. The decrease was partially offset by the impact of basic customer rate increases, and customer growth mainly in Canada, in addition to the favourable impact of foreign currency translation. Net earnings applicable to common shares grew $17 million, or 6.9 per cent, over 2008. Earnings in 2008 were enhanced by a one-time $7.5 million tax reduction at Terasen and were reduced by one-time charges of approximately $15 million pertaining to Belize Electricity and FortisOntario. Earnings in 2009 were favourably impacted by a one-time $3 million adjustment to future income taxes related to prior periods at FortisOntario and were reduced by a one-time $5 million after-tax provision for additional costs related to the conversion of Whistler customer appliances from propane to natural gas. Excluding the above items, earnings were higher year over year mainly due to the impact of an increase in the allowed ROEs for 2009 at FortisAlberta and TGI and an increase in the deemed equity component of the total capital structure at FortisAlberta, combined with rate base growth mainly at the electric utilities in western Canada. Growth in earnings was partially offset by lower contribution from non-regulated generation operations in Ontario due to the expiration of the Rankine water rights in April 2009, and ongoing regulatory challenges at Belize Electricity. The growth in total assets was primarily due to the Corporation's continued investment in energy systems, driven by the capital expenditure programs at FortisAlberta, FortisBC and the Terasen Gas companies, and an increase in regulatory assets driven by the adoption of the amended accounting standard pertaining to income taxes. The increase was partially offset by the unfavourable impact of foreign exchange associated with translation of foreign currency-denominated assets. The increase in long-term debt was in support of energy infrastructure investment, partially offset by the impact of foreign exchange. Basic earnings per common share decreased 2 cents, or 1.3 per cent, from 2008 due to dilution associated with the issuance of $300 million common shares in December 2008.

2008/2007: Revenue increased approximately $1.2 billion, or 43.6 per cent, over 2007. The increase was driven by contribution from the Terasen Gas companies for a full year in 2008 compared to a partial year in 2007. Net earnings applicable to common shares grew $52 million, or 26.9 per cent, over 2007. The increase in earnings was primarily due to earnings' contribution from the Terasen Gas companies for a full year in 2008 compared to a partial year in 2007, rate base growth and higher allowed ROEs at the Corporation's Canadian Regulated Utilities, and increased non-regulated hydroelectric production due to higher rainfall. The increase was tempered by a one-time $13 million loss related to a June 2008 regulatory rate decision at Belize Electricity and lower corporate income tax recoveries at FortisAlberta. The growth in total assets and increase in long-term debt in 2008 was primarily due to the Corporation's continued investment in energy systems, driven by the capital expenditure programs at FortisAlberta, FortisBC and the Terasen Gas companies, combined with the impact of foreign exchange associated with translation of foreign currency-denominated assets and liabilities. The Corporation issued $230 million preference shares in 2008, the net proceeds of which were primarily used to repay borrowings under the Corporation's committed credit facility, to fund equity requirements of FortisAlberta and the Corporation's regulated electric utilities in the Caribbean, and for general corporate purposes. The Corporation also issued $300 million common shares in 2008, the net proceeds of which were used to repay short-term debt primarily incurred to retire $200 million of maturing debt at Terasen, and for general corporate purposes. Basic earnings per common share increased 16 cents, or 11.4 per cent, from 2007, primarily due to growth in earnings.

Fourth Quarter Results

The following tables set forth unaudited financial information for the quarters ended December 31, 2009 and 2008. The financial information has been prepared in Canadian dollars and in accordance with Canadian GAAP and as required by utility regulators. A discussion of the financial results for the fourth quarter of 2009 is also contained in the Corporation's fourth quarter 2009 media release, dated and filed on SEDAR at www.sedar.com on February 4, 2010, which is incorporated by reference in this MD&A.

Summary of Volumes, Sales and Revenue

Fourth Quarters Ended December 31 *(Unaudited)*	**Gas Volumes** *(TJ)* **Energy and Electricity Sales** *(GWh)*			**Revenue** *($ millions)*		
	2009	2008	Variance	**2009**	2008	Variance
Regulated Gas Utilities – Canadian						
Terasen Gas Companies	**65,000**	66,816	(1,816)	**497**	606	(109)
Regulated Electric Utilities – Canadian						
FortisAlberta	**4,129**	4,068	61	**86**	78	8
FortisBC	**859**	842	17	**69**	66	3
Newfoundland Power	**1,474**	1,412	62	**146**	139	7
Other Canadian	**582**	543	39	**77**	65	12
	7,044	6,865	179	**378**	348	30
Regulated Electric Utilities – Caribbean	**290**	364	(74)	**85**	159	(74)
Non-Regulated – Fortis Generation	**87**	312	(225)	**5**	20	(15)
Non-Regulated – Fortis Properties				**53**	52	1
Corporate and Other				**6**	6	–
Inter-Segment Eliminations				**(6)**	(10)	4
Total				**1,018**	1,181	(163)

Gas Volumes: Gas volumes at the Terasen Gas companies decreased quarter over quarter, mainly due to lower average consumption by core residential customers.

Energy and Electricity Sales: Increased energy and electricity sales at Regulated Electric Utilities – Canadian quarter over quarter were driven by customer growth at FortisAlberta, FortisBC and Newfoundland Power, and contribution from Algoma Power, which has been included in the financial results reported in the Other Canadian Regulated Electric Utilities' segment from October 8, 2009, the date of acquisition by FortisOntario, partially offset by the negative impact on consumption at the Other Canadian Regulated Electric Utilities, due to the temporary shutdown of two commercial potato-processing plants on Prince Edward Island and lower average consumption as a result of the economic downturn.

Decreased electricity sales at Regulated Electric Utilities – Caribbean were driven by the impact of two additional months of contribution from Caribbean Utilities in the fourth quarter of 2008 (August and September 2008) related to a change in the utility's fiscal year end. The decrease was partially offset by the favourable impact on consumption as a result of warmer average temperatures experienced in the region compared to the same quarter in 2008 and the loss of electricity sales during the third and fourth quarters of 2008 at Fortis Turks and Caicos as a result of Hurricane Ike, which struck in September 2008. Tempering electricity sales growth, however, was the negative impact of the economic downturn on consumption by residential customers and activities in the tourism, oil, construction and related industries.

At Non-Regulated – Fortis Generation, 164 GWh of the total decrease in energy sales quarter over quarter was due to the expiration, on April 30, 2009, of the water rights of the Rankine hydroelectric generating facility in Ontario. In addition, 46 GWh of the total decrease in energy sales quarter over quarter related to generation operations in central Newfoundland. Energy sales for 2009 included sales related to central Newfoundland operations for only 1½ months compared to the entire year in 2008, due to the discontinuance of the consolidation method of accounting for these operations in February 2009. The remaining decrease in total energy sales was mainly due to the impact of lower production in Belize and Upper New York State driven by lower rainfall.

Revenue: The decrease in revenue at the Terasen Gas companies was largely due to the lower commodity cost of natural gas charged to customers and lower consumption, partially offset by higher basic customer delivery rates and the rate revenue accrual, during the fourth quarter of 2009, related to the cumulative retroactive impact of an increase in the allowed ROEs for the Terasen Gas companies, effective July 1, 2009.

The increase in revenue at Regulated Electric Utilities – Canadian was mainly due to basic customer rate increases and customer growth, combined with contribution from Algoma Power, from October 2009, and the rate revenue accrual, during the fourth quarter of 2009, related to the cumulative retroactive impact of an increase in FortisAlberta's allowed ROE to 9.00 per cent, effective January 1, 2009, from an interim allowed ROE of 8.51 per cent and an increase in the deemed equity component of the total capital structure to 41 per cent from 37 per cent.

Revenue at Regulated Electric Utilities – Caribbean decreased quarter over quarter, mainly due to the flow through to customers of lower energy supply costs at Caribbean Utilities, two additional months of contribution from Caribbean Utilities in the fourth quarter of 2008 (August and September 2008) for the reason described above, and the unfavourable impact of foreign currency translation. Partially offsetting the above factors was the impact of a 2.4 per cent increase in basic electricity rates at Caribbean Utilities, effective June 1, 2009, and otherwise increased electricity sales when comparing electricity sales for the same three-month period quarter over quarter for Caribbean Utilities.

Revenue from Non-Regulated – Fortis Generation decreased quarter over quarter, primarily due to the loss of revenue subsequent to the expiration of the Rankine water rights, as described above, the impact of the discontinuance of the consolidation method of accounting for the financial results of the generation operations in central Newfoundland in February 2009, as described above, lower average wholesale market energy prices per MWh in Upper New York State, which were US$40.66 for the fourth quarter of 2009 compared to US$56.86 for the same quarter in 2008, and decreased production in Upper New York State and Belize.

Summary of Net Earnings Applicable to Common Shares

Fourth Quarters Ended December 31 *(Unaudited)*

($ millions)	**2009**	2008	Variance
Regulated Gas Utilities – Canadian			
Terasen Gas Companies	**48**	47	1
Regulated Electric Utilities – Canadian			
FortisAlberta	**15**	11	4
FortisBC	**8**	7	1
Newfoundland Power	**8**	8	–
Other Canadian	**6**	3	3
	37	29	8
Regulated Electric Utilities – Caribbean	**7**	8	(1)
Non-Regulated – Fortis Generation	**3**	8	(5)
Non-Regulated – Fortis Properties	**5**	4	1
Corporate and Other	**(19)**	(20)	1
Net Earnings Applicable to Common Shares	**81**	76	5

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

Summary of Cash Flows

Fourth Quarters Ended December 31 *(Unaudited)*

($ millions)	**2009**	2008	Variance
Cash, Beginning of Period	**106**	68	38
Cash Provided By (Used In)			
Operating Activities	**70**	208	(138)
Investing Activities	**(312)**	(272)	(40)
Financing Activities	**222**	59	163
Foreign Currency Impact on Cash Balances	**(1)**	3	(4)
Cash, End of Period	**85**	66	19

Cash flow provided by operating activities, after working capital adjustments, decreased $138 million quarter over quarter. The decrease was mainly due to unfavourable working capital changes at the Terasen Gas companies, reflecting differences in the commodity cost of natural gas and the cost of natural gas charged to customers quarter over quarter, and the timing of the declaration of common share dividends.

Cash used in investing activities increased $40 million quarter over quarter, reflecting the acquisition of Algoma Power during the fourth quarter of 2009 for approximately $70 million, net of cash acquired, compared to the acquisition of the Sheraton Hotel Newfoundland during the fourth quarter of 2008 for approximately $22 million, partially offset by lower capital spending by the utilities in the Caribbean.

Cash provided by financing activities was $163 million higher quarter over quarter, primarily due to a net increase in debt during the fourth quarter of 2009 compared to a net decrease in debt during the fourth quarter of 2008, partially offset by lower proceeds from common share offerings. During the fourth quarter of 2008, Fortis issued $300 million in common shares.

Summary of Quarterly Results

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2008 through December 31, 2009. The quarterly information has been prepared in Canadian dollars and 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. These 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)

	Revenue	**Net Earnings Applicable to Common Shares**	**Earnings per Common Share**	
Quarter Ended	*($ millions)*	*($ millions)*	**Basic** *($)*	**Diluted** *($)*
December 31, 2009	1,018	81	0.48	0.46
September 30, 2009	664	36	0.21	0.21
June 30, 2009	754	53	0.31	0.31
March 31, 2009	1,201	92	0.54	0.52
December 31, 2008	1,181	76	0.48	0.46
September 30, 2008	727	49	0.31	0.31
June 30, 2008	848	29	0.19	0.18
March 31, 2008	1,146	91	0.58	0.55

A summary of the past eight quarters reflects the Corporation's continued organic growth and growth from acquisitions, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of gas and electricity demand and water flows, as well as the timing and recognition of regulatory decisions. Revenue is also affected by the cost of fuel and purchased power and the commodity cost of natural gas, which are flowed through to customers without markup. Given the diversified nature of the Fortis companies, seasonality may vary. Most of the annual earnings of the Terasen Gas companies are generated in the first and fourth quarters. Financial results from May 1, 2009 have been impacted, as expected, by the loss of revenue and earnings subsequent to the expiration, in April 2009, of the water rights of the Rankine hydroelectric generating facility in Ontario. Financial results for the second quarter ended June 30, 2008 reflected the $13 million unfavourable impact to Fortis of a charge recorded at Belize Electricity as a result of the June 2008 regulatory rate decision. Financial results for the fourth quarter ended December 31, 2008 included two additional months of contribution from Caribbean Utilities resulting from a change in the utility's fiscal year end. To a lesser degree, financial results from November 2008 were impacted by the acquisition of the Sheraton Hotel Newfoundland, from April 2009 by the acquisition of the Holiday Inn Select Windsor, and from October 2009 by the acquisition of Algoma Power.

December 2009/December 2008 – Net earnings applicable to common shares were $81 million, or $0.48 per common share, for the fourth quarter of 2009 compared to earnings of $76 million, or $0.48 per common share, for the fourth quarter of 2008. A discussion of the variances between the financial results for the fourth quarter of 2009 and the fourth quarter of 2008 is provided in the "Fourth Quarter Results" section of this MD&A.

September 2009/September 2008 – Net earnings applicable to common shares were $36 million, or $0.21 per common share, for the third quarter of 2009 compared to earnings of $49 million, or $0.31 per common share, for the third quarter of 2008. Third quarter 2008 results included a tax reduction of approximately $7.5 million associated with the settlement of historical corporate tax matters at Terasen and a $4.5 million recovery of future income taxes, which was previously expensed during the first half of 2008 at FortisAlberta. Earnings were $1 million lower quarter over quarter, excluding the above one-time tax reductions. The impact of lower effective corporate income taxes at the Terasen Gas companies and growth in electrical infrastructure investment and higher net transmission revenue at FortisAlberta was more than offset by lower earnings from non-regulated hydroelectric generation and lower earnings at Newfoundland Power. The decrease in earnings from non-regulated hydroelectric generation was primarily associated with the loss of earnings subsequent to the expiration, on April 30, 2009, of the water rights of the Rankine hydroelectric generating facility in Ontario. Lower earnings at Newfoundland Power were largely associated with higher operating expenses and amortization costs.

June 2009/June 2008 – Net earnings applicable to common shares were $53 million, or $0.31 per common share, for the second quarter of 2009 compared to earnings of $29 million, or $0.19 per common share, for the second quarter of 2008. Results for the second quarter of 2008 included one-time charges of approximately $15 million pertaining to Belize Electricity, associated with the June 2008 regulatory rate decision, and FortisOntario, associated with the repayment, during the second quarter of 2008, of an interconnection agreement-related refund received in the fourth quarter of 2007. Excluding these one-time charges, earnings increased $9 million quarter over quarter, driven by lower corporate income taxes and growth in electrical infrastructure investment at FortisAlberta, and lower corporate income taxes at the Terasen Gas companies. The increase was partially offset by lower earnings from non-regulated hydroelectric generation primarily associated with the loss of earnings subsequent to the expiration, on April 30, 2009, of the water rights of the Rankine hydroelectric generating facility in Ontario.

March 2009/March 2008 – Net earnings applicable to common shares were $92 million, or $0.54 per common share, for the first quarter of 2009 compared to earnings of $91 million, or $0.58 per common share, for the first quarter of 2008. Results were driven by growth in electrical infrastructure investment and customers at the Regulated Electric Utilities in western Canada, partially offset by lower earnings at Regulated Electric Utilities – Caribbean and Fortis Properties. Excluding one-time gains of approximately $2 million at Fortis Turks and Caicos in 2009, earnings at Regulated Electric Utilities – Caribbean were $3 million lower quarter over quarter, resulting from reduced electricity sales attributable to cooler temperatures and the impact of the economic downturn on energy demand, combined with the lower allowed ROAs at Caribbean Utilities and Belize Electricity. The decrease was partially mitigated by the favourable impact of foreign exchange rates associated with the strengthening US dollar quarter over quarter. Fortis Properties' results were reduced by one-time transitional operating costs associated with the Sheraton Hotel Newfoundland, acquired in November 2008, and the impact of lower hotel occupancies.

Management's Evaluation of Disclosure Controls and Procedures and Internal Controls over Financial Reporting

Disclosure Controls and Procedures

The President and Chief Executive Officer ("CEO") and the Vice President, Finance and Chief Financial Officer ("CFO") of Fortis, together with management, have established and maintain disclosure controls and procedures for the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's disclosure controls and procedures as of December 31, 2009 and, based on that evaluation, have concluded that these controls and procedures are effective in providing such reasonable assurance.

Internal Controls over Financial Reporting

The CEO and CFO of Fortis, together with management, are also responsible for establishing and maintaining internal controls over financial reporting ("ICFR") within the Corporation in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's ICFR as of December 31, 2009 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance.

During the fourth quarter of 2009, there was no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

Subsequent Event

In January 2010, Fortis completed a $250 million five-year fixed rate reset preference share offering. The net proceeds of $242 million were used to repay borrowings under the Corporation's committed credit facility and to fund an equity injection into TGI to repay borrowings under the utility's credit facilities in support of working capital and capital expenditure requirements.

Outlook

The Corporation's significant capital program, which is expected to approach $5 billion over the next five years, should drive growth in earnings and dividends.

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

Outstanding Share Data

As at March 1, 2010, the Corporation had issued and outstanding 172.1 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 that would be issued upon conversion of share options, convertible debt and First Preference Shares, Series C and First Preference Shares, Series E as at March 1, 2010 is as follows:

Conversion of Securities into Common Shares

As at March 1, 2010 *(Unaudited)*

Security	**Number of Common Shares** *(millions)*
Stock Options	**5.5**
Convertible Debt	**1.4**
First Preference Shares, Series C	**4.7**
First Preference Shares, Series E	**7.6**
Total	**19.2**

Additional information, including the Fortis 2009 Annual Information Form, Management Information Circular and Consolidated Financial Statements, is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisinc.com.

Financials

Management's Report

The accompanying Annual Consolidated Financial Statements of Fortis Inc. and all information in the 2009 Annual Report have been prepared by management, who are responsible for the integrity of the information presented including the amounts that must, of necessity, be based on estimates and informed judgments. These Annual Consolidated Financial Statements were prepared in accordance with accounting principles generally accepted in Canada. Financial information contained elsewhere in the 2009 Annual Report is consistent with that in the Annual Consolidated Financial Statements.

In meeting its responsibility for the reliability and integrity of the Annual Consolidated Financial Statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Corporation and its subsidiaries focus on the need for training of qualified and professional staff and the effective communication of management guidelines and policies. The effectiveness of the internal controls of Fortis Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibilities for financial reporting through an Audit Committee which is composed entirely of outside independent directors. The Audit Committee oversees the external audit of the Corporation's Annual Consolidated Financial Statements and the accounting and financial reporting and disclosure processes and policies of the Corporation. The Audit Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the external audit, the adequacy of the internal accounting controls and the quality and integrity of financial reporting. The Corporation's Annual Consolidated Financial Statements are reviewed by the Audit Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit Committee. The Audit Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Corporation's Annual Consolidated Financial Statements and to review and report to the Board of Directors on policies relating to the accounting and financial reporting and disclosure processes.

The Audit Committee has the duty to review financial reports requiring Board of Directors' approval prior to the submission to securities commissions or other regulatory authorities, to assess and review management judgments material to reported financial information and to review shareholders' auditors' independence and auditors' fees. The 2009 Annual Consolidated Financial Statements and Management Discussion and Analysis contained in the 2009 Annual Report were reviewed by the Audit Committee and, on their recommendation, were approved by the Board of Directors of Fortis Inc. Ernst & Young, LLP, independent auditors appointed by the shareholders of Fortis Inc. upon recommendation of the Audit Committee, have performed an audit of the 2009 Annual Consolidated Financial Statements and their report follows.

H. Stanley Marshall
President and Chief Executive Officer

Barry V. Perry
Vice President, Finance and Chief Financial Officer

St. John's, Canada

Auditors' Report

To the Shareholders of Fortis Inc.

We have audited the consolidated balance sheets of Fortis Inc. as at December 31, 2009 and 2008 and the consolidated statements of earnings, retained earnings, comprehensive income and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2009 and 2008 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP
Chartered Accountants

St. John's, Canada
February 4, 2010

Consolidated Balance Sheets

FORTIS INC.

(Incorporated under the laws of the Province of Newfoundland and Labrador)

As at December 31 (in millions of Canadian dollars)

ASSETS	2009	2008
Current assets		*(Restated – Note 2)*
Cash and cash equivalents	**$ 85**	$ 66
Accounts receivable	**595**	681
Prepaid expenses	**16**	17
Regulatory assets *(Note 4)*	**223**	157
Inventories *(Note 5)*	**178**	229
Future income taxes *(Note 19)*	**29**	–
	1,126	1,150
Other assets *(Note 6)*	**174**	230
Regulatory assets *(Note 4)*	**758**	203
Future income taxes *(Note 19)*	**17**	54
Utility capital assets *(Note 7)*	**7,687**	7,141
Income producing properties *(Note 8)*	**559**	540
Intangible assets *(Note 9)*	**279**	273
Goodwill *(Note 10)*	**1,560**	1,575
	$ 12,160	$ 11,166
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings *(Note 26)*	**$ 415**	$ 410
Accounts payable and accrued charges	**852**	874
Dividends payable	**3**	47
Income taxes payable	**23**	66
Regulatory liabilities *(Note 4)*	**53**	45
Current installments of long-term debt and capital lease obligations *(Note 11)*	**224**	240
Future income taxes *(Note 19)*	**24**	15
	1,594	1,697
Deferred credits *(Note 12)*	**295**	277
Regulatory liabilities *(Note 4)*	**436**	389
Future income taxes *(Note 19)*	**576**	61
Long-term debt and capital lease obligations *(Note 11)*	**5,276**	4,884
Non-controlling interest *(Note 13)*	**123**	145
Preference shares *(Note 14)*	**320**	320
	8,620	7,773
Shareholders' equity		
Common shares *(Note 15)*	**2,497**	2,449
Preference shares *(Note 14)*	**347**	347
Contributed surplus	**11**	9
Equity portion of convertible debentures *(Note 11)*	**5**	6
Accumulated other comprehensive loss *(Note 17)*	**(83)**	(52)
Retained earnings	**763**	634
	3,540	3,393
	$ 12,160	$ 11,166

Commitments *(Note 27)*

Contingent Liabilities *(Note 28)*

See accompanying Notes to Consolidated Financial Statements

Approved on Behalf of the Board

Geoffrey F. Hyland, Director

David G. Norris, Director

Consolidated Statements of Earnings

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)	**2009**	2008
Revenue	**$ 3,637**	$ 3,903
Expenses		
Energy supply costs	**1,799**	2,112
Operating	**773**	743
Amortization	**364**	348
	2,936	3,203
Operating Income	**701**	700
Finance charges *(Note 18)*	**360**	363
Earnings Before Corporate Taxes and Non-Controlling Interest	**341**	337
Corporate taxes *(Note 19)*	**49**	65
Net Earnings Before Non-Controlling Interest	**292**	272
Non-controlling interest	**12**	13
Net Earnings	**280**	259
Preference share dividends	**18**	14
Net Earnings Applicable to Common Shares	**$ 262**	$ 245
Earnings Per Common Share *(Note 15)*		
Basic	**$ 1.54**	$ 1.56
Diluted	**$ 1.51**	$ 1.52

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Retained Earnings

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2009**	2008
Balance at Beginning of Year	**$ 634**	$ 551
Net Earnings Applicable to Common Shares	**262**	245
	896	796
Dividends on Common Shares	**(133)**	(162)
Balance at End of Year	**$ 763**	$ 634

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Comprehensive Income

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2009**	2008
Net Earnings	**$ 280**	$ 259
Other Comprehensive Income (Loss)		
Unrealized foreign currency translation (losses) gains on net investments in self-sustaining foreign operations	**(90)**	115
Gains (losses) on hedges of net investments in self-sustaining foreign operations	**67**	(92)
Corporate tax (expense) recovery	**(9)**	13
Change in Unrealized Foreign Currency Translation (Losses) Gains, Net of Hedging Activities and Tax *(Note 17)*	**(32)**	36
Gain on Derivative Instruments Designated as Cash Flow Hedges, Net of Tax	**1**	–
Comprehensive Income	**$ 249**	$ 295

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Cash Flows

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2009**	2008
		(Restated – Note 2)
Operating Activities		
Net earnings	**$ 280**	$ 259
Items not Affecting Cash:		
Amortization – utility capital assets and income producing properties	**317**	308
Amortization – intangible assets	**43**	37
Amortization – other	**4**	3
Future income taxes *(Note 19)*	**5**	14
Non-controlling interest	**12**	13
Write-down of deferred power costs – Belize Electricity *(Note 4)*	**–**	18
Other	**(8)**	(7)
Change in long-term regulatory assets and liabilities	**25**	(23)
	678	622
Change in non-cash operating working capital	**(41)**	39
	637	661
Investing Activities		
Change in other assets and deferred credits	**(8)**	5
Capital expenditures – utility capital assets	**(966)**	(872)
Capital expenditures – income producing properties	**(26)**	(14)
Capital expenditures – intangible assets	**(32)**	(49)
Contributions in aid of construction	**56**	85
Proceeds on sale of capital assets	**1**	15
Business acquisitions, net of cash acquired *(Note 21)*	**(77)**	(22)
	(1,052)	(852)
Financing Activities		
Change in short-term borrowings	**8**	(69)
Proceeds from long-term debt, net of issue costs	**729**	662
Repayments of long-term debt and capital lease obligations	**(172)**	(431)
Net repayments under committed credit facilities	**(14)**	(309)
Advances from non-controlling interest	**2**	3
Issue of common shares, net of costs	**46**	308
Issue of preference shares, net of costs	**–**	223
Dividends		
Common shares	**(133)**	(162)
Preference shares	**(18)**	(14)
Subsidiary dividends paid to non-controlling interest	**(10)**	(15)
	438	196
Effect of exchange rate changes on cash and cash equivalents	**(4)**	3
Change in Cash and Cash Equivalents	**19**	8
Cash and Cash Equivalents, Beginning of Year	**66**	58
Cash and Cash Equivalents, End of Year	**$ 85**	$ 66

Supplementary Information to Consolidated Statements of Cash Flows *(Note 23)*

See accompanying Notes to Consolidated Financial Statements

1. Description of the Business

Nature of Operations

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

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

The following summary describes the Corporation's interests in regulated gas and electric utilities in Canada and the Caribbean by utility:

Regulated Gas Utilities – Canadian

Terasen Gas Companies: Includes Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGWI").

TGI is the largest distributor of natural gas in British Columbia, serving primarily residential, commercial and industrial customers in a service area that extends from Vancouver to the Fraser Valley and the interior of British Columbia.

TGVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island, and the distribution system on Vancouver Island and along the Sunshine Coast of British Columbia, serving primarily residential, commercial and industrial customers.

In addition to providing transmission and distribution ("T&D") services to customers, TGI and TGVI also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through TGI's Southern Crossing Pipeline, from Alberta.

TGWI owns and operates the newly converted natural gas distribution system in the Resort Municipality of Whistler ("Whistler"), British Columbia, which provides service mainly to residential and commercial customers.

Regulated Electric Utilities – Canadian

a. *FortisAlberta*: FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta.

b. *FortisBC*: Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 223 megawatts ("MW"). Included with the FortisBC component of the Regulated Electric Utilities – Canadian segment are the operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Cominco Metals Ltd., the 149-MW Brilliant hydroelectric plant and 120-MW Brilliant expansion plant, both owned by Columbia Power Corporation and the Columbia Basin Trust ("CPC/CBT"), the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT and the distribution system owned by the City of Kelowna.

c. *Newfoundland Power*: Newfoundland Power is the principal distributor of electricity in Newfoundland. Newfoundland Power has an installed generating capacity of 140 MW, of which 97 MW is hydroelectric generation.

d. *Other Canadian*: Includes Maritime Electric and FortisOntario. Maritime Electric is the principal distributor of electricity on Prince Edward Island. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations include Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and, as of October 2009, Algoma Power Inc. ("Algoma Power") (Note 21). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc. ("Port Colborne Hydro"), which has been leased from the City of Port Colborne under a ten-year lease agreement that expires in April 2012. FortisOntario also owns a 10 per cent interest in each of Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc., three regional electric distribution companies.

Regulated Electric Utilities – Caribbean

a. *Belize Electricity*: Belize Electricity is the principal distributor of electricity in Belize, Central America. The Company has an installed generating capacity of 34 MW. Fortis holds an approximate 70 per cent controlling ownership interest in Belize Electricity.

b. *Caribbean Utilities*: Caribbean Utilities is the sole provider of electricity on Grand Cayman, Cayman Islands. The Company has an installed generating capacity of 153 MW. Fortis holds an approximate 59 per cent controlling ownership interest in Caribbean Utilities. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U). Previously, Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, its financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. In 2008, Caribbean Utilities changed its fiscal year end to December 31, which has eliminated the previous two-month lag in consolidating its financial results.

c. *Fortis Turks and Caicos*: Includes P.P.C. Limited ("PPC") and Atlantic Equipment & Power (Turks and Caicos) Ltd. ("Atlantic"). Fortis Turks and Caicos is the principal distributor of electricity in the Turks and Caicos Islands. The Company has a combined diesel-powered generating capacity of 54 MW.

Non-Regulated – Fortis Generation

a. *Belize*: Operations consist of the 25-MW Mollejon, the 7-MW Chalillo and, as of March 2010, the 19-MW Vaca hydroelectric generating facilities in Belize. All of the output of these facilities is sold to Belize Electricity under 50-year power purchase agreements expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirect wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the Government of Belize.

b. *Ontario*: Includes six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW and a 5-MW gas-powered cogeneration plant in Cornwall. The 75 MW of water-right entitlement associated with the Rankine hydroelectric generating facility at Niagara Falls expired on April 30, 2009, at the end of a 100-year term.

c. *Central Newfoundland*: Through the Exploits River Hydro Partnership (the "Exploits Partnership"), a partnership between the Corporation, through its wholly owned subsidiary Fortis Properties, and AbitibiBowater Inc. ("Abitibi"), 36 MW of additional capacity was developed and installed at two of Abitibi's hydroelectric generating plants in central Newfoundland. Fortis Properties holds directly a 51 per cent interest in the Exploits Partnership and Abitibi holds the remaining 49 per cent interest. The Exploits Partnership sells its output to Newfoundland and Labrador Hydro under a 30-year power purchase agreement expiring in 2033. Effective February 12, 2009, Fortis discontinued the consolidation method of accounting for its investment in the Exploits Partnership (Note 28).

d. *British Columbia*: Includes the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia. The plant sells its entire output to BC Hydro under a long-term contract expiring in 2013.

e. *Upper New York State*: Includes the operations of four hydroelectric generating stations in Upper New York State, with a combined capacity of approximately 23 MW, operating under licences from the U.S. Federal Energy Regulatory Commission. Hydroelectric generation operations in Upper New York State are conducted through the Corporation's indirect wholly owned subsidiary FortisUS Energy Corporation ("FortisUS Energy").

Non-Regulated – Fortis Properties

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

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment. This segment includes corporate finance charges, including interest on debt incurred directly by Fortis and Terasen Inc. ("Terasen") and dividends on preference shares classified as long-term liabilities; dividends on preference shares classified as equity; other corporate expenses, including Fortis and Terasen corporate operating costs, net of recoveries from subsidiaries; interest and miscellaneous revenue; and corporate income taxes.

Also included in the Corporate and Other segment are the financial results of CustomerWorks Limited Partnership ("CWLP"). CWLP is a non-regulated shared-services business in which Terasen holds a 30 per cent interest. CWLP operates in partnership with Enbridge Inc. and provides customer service contact, meter reading, billing, credit, support and collection services to the Terasen Gas companies and several smaller third parties. CWLP's financial results are recorded using the proportionate consolidation method of accounting. The financial results of Terasen Energy Services Inc. ("TES") are also reported in the Corporate and Other segment. TES is a non-regulated wholly owned subsidiary of Terasen that provides alternative energy solutions.

2. Summary of Significant Accounting Policies

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"), including selected accounting treatments that differ from those used by entities not subject to rate regulation. 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 by entities not subject to rate regulation. The differences are described in Note 2 under the headings Regulation, Utility Capital Assets, Intangibles, Employee Future Benefits, Income Taxes and Revenue Recognition, and in Note 4.

All amounts presented are in Canadian dollars unless otherwise stated.

Regulation

Effective January 1, 2009, the Canadian Accounting Standards Board (the "AcSB") amended the Canadian Institute of Chartered Accountants ("CICA") Handbook: (i) Section 1100, *Generally Accepted Accounting Principles*, removing the temporary exemption providing relief to entities subject to rate regulation from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation; and (ii) Section 3465, *Income Taxes*, to require the recognition of future income tax liabilities and assets, as well as offsetting regulatory assets and liabilities, by entities subject to rate regulation.

Effective January 1, 2009, with the removal of the temporary exemption in Section 1100, the Corporation must now apply Section 1100 to the recognition of assets and liabilities arising from rate regulation. Certain assets and liabilities arising from rate regulation continue to have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*. The assets and liabilities arising from rate regulation, as described in Note 4, do not have specific guidance under a primary source of Canadian GAAP. Therefore, Section 1100 directs the Corporation to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in Section 1000, *Financial Statement Concepts*. In developing these accounting policies, the Corporation may consult other sources, including pronouncements issued by bodies authorized to issue accounting standards in other jurisdictions. Therefore, in accordance with Section 1100, the Corporation has determined that all of its regulatory assets and liabilities qualify for recognition under Canadian GAAP, and this recognition is consistent with the U.S. Financial Accounting Standards Board's Accounting Standard Codification 980, *Regulated Operations*. Therefore, there was no effect on the Corporation's consolidated financial statements as at January 1, 2009 as a result of the removal of the temporary exemption from Section 1100.

The nature of regulation at the Corporation's utilities is as follows:

Terasen Gas Companies and FortisBC

The Terasen Gas companies and FortisBC are regulated by the British Columbia Utilities Commission ("BCUC"). The BCUC administers acts and regulations pursuant to the *Utilities Commission Act* (British Columbia), covering such matters as tariffs, rates, construction, operations, financing and accounting. TGI, TGVI and FortisBC operate under cost of service regulation and, from time to time, performance-based rate-setting ("PBR") mechanisms as administered by the BCUC. The PBR mechanism for TGI expired on December 31, 2009 as a recent BCUC-approved Negotiated Settlement Agreement ("NSA") did not include a PBR mechanism, effective January 1, 2010.

The BCUC provides for the use of a future test year in the establishment of rates and, pursuant to this method, provides for the forecasting of energy to be sold, together with all the costs of the utilities, and provides a rate of return on a deemed capital structure applied to approved rate base assets. Rates are fixed to permit the utilities to collect all of their costs, including the allowed rate of return on common shareholders' equity ("ROE").

TGI, TGVI and FortisBC apply for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment and/or through the operation of the PBR mechanisms.

Under the previous PBR mechanism, TGI and customers equally shared in achieved earnings above or below the allowed ROE. During 2008, the BCUC extended the PBR mechanism for FortisBC for the years 2009 through 2011. Under the PBR mechanism, FortisBC and customers equally share achieved earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE. Any excess is subject to deferral treatment. FortisBC's portion of the PBR incentive is subject to the Company meeting certain performance standards and BCUC approval.

TGI's allowed ROE was 8.47 per cent for January through June 2009 and 9.50 per cent effective July 1, 2009 (2008 – 8.62 per cent) on a deemed capital structure of 35 per cent common equity. TGVI's allowed ROE was 9.17 per cent for January through June 2009 and 10.00 per cent effective July 1, 2009 (2008 – 9.32 per cent) on a deemed capital structure of 40 per cent common equity. Effective January 1, 2010, the deemed equity component of TGI's capital structure increased to 40 per cent. FortisBC's allowed ROE was 8.87 per cent for 2009 (2008 – 9.02 per cent) on a deemed capital structure of 40 per cent common equity.

Previously, the allowed ROE at each of TGI, TGVI and FortisBC was adjusted annually through the operation of an automatic adjustment formula for forecast changes in long-term Canada bond yields. Effective July 1, 2009, the BCUC has set the allowed ROEs for TGI and TGVI at 9.50 per cent and 10.00 per cent, respectively, and effective January 1, 2010 has set the allowed ROE for FortisBC at 9.90 per cent. The BCUC has determined that the former automatic adjustment formula used to establish ROE on an annual basis no longer applies until reviewed further by the BCUC.

FortisAlberta

FortisAlberta is regulated by the Alberta Utilities Commission ("AUC") pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Board Act* (Alberta), the *Hydro and Electric Energy Act* (Alberta) and the *AUC Act* (Alberta). The AUC administers these acts and regulations, covering such matters as tariffs, rates, construction, operations and financing.

FortisAlberta operates under cost of service regulation as prescribed by the AUC. The AUC provides for the use of a future test year in the establishment of rates associated with the distribution business and, pursuant to this method, rate orders issued by the AUC establish the Company's revenue requirements, being those revenues required to recover approved costs associated with the distribution business and provide a rate of return on a deemed capital structure applied to approved rate base assets. FortisAlberta's allowed ROE was 9.00 per cent for 2009 (2008 – 8.75 per cent) on a deemed capital structure of 41 per cent common equity (2008 – 37 per cent). The Company applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

Previously, FortisAlberta's allowed ROE was adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields. In its November 2009 Generic Cost of Capital Decision, the AUC ordered that the allowed ROE for utilities it regulates in Alberta be set at 9.00 per cent for 2009, 2010 and, on an interim basis, 2011 and that the automatic adjustment formula used to establish ROE no longer apply until reviewed further by the AUC.

Newfoundland Power

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") under the *Public Utilities Act* (Newfoundland and Labrador). The *Public Utilities Act* (Newfoundland and Labrador) provides for the PUB's general supervision of the Company's utility operation and requires the PUB to approve, among other things, customer rates, capital expenditures and the issuance of securities of Newfoundland Power. Newfoundland Power operates under cost of service regulation as administered by the PUB. The PUB provides for the use of a future test year in the establishment of rates for the utility and, pursuant to this method, the determination of the forecast rate of return on approved rate base and deemed capital structure, together with the forecast of all reasonable and prudent costs, establish the revenue requirement upon which Newfoundland Power's customer rates are determined. While Newfoundland Power's allowed ROE has been set at 9.00 per cent by the PUB for 2010, the utility's allowed ROE is normally adjusted annually, between test years, through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields.

Newfoundland Power's allowed ROE for 2009 was 8.95 per cent (2008 – 8.95 per cent) on a deemed capital structure of 45 per cent common equity. The Company applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

Maritime Electric

Maritime Electric operates under a cost of service regulatory model as prescribed by the Island Regulatory and Appeals Commission ("IRAC") under the provisions of the *Electric Power Act* (Prince Edward Island). IRAC uses a future test year in the establishment of rates for the utility and, pursuant to this method, rate orders are based on estimated costs and provide an approved rate of return on a deemed capital structure applied to approved rate base assets. Maritime Electric's allowed ROE was 9.75 per cent for 2009 (2008 – 10.00 per cent) on a deemed capital structure of 40 per cent common equity. Maritime Electric applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

FortisOntario

Canadian Niagara Power, Algoma Power and Cornwall Electric operate under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario), as administered by the Ontario Energy Board ("OEB"). Canadian Niagara Power and Algoma Power operate under cost of service regulation and earnings are regulated on the basis of rate of return on rate base, plus a recovery of allowable distribution costs.

2. Summary of Significant Accounting Policies (cont'd)

Regulation (cont'd)

Canadian Niagara Power's allowed ROE was 8.01 per cent for 2009 (2008 – 9.00 per cent) on a deemed capital structure of 43.3 per cent common equity (2008 – 46.7 per cent). In 2008, Canadian Niagara Power's electricity distribution rates were based upon costs derived from a 2004 historical test year whereas, effective May 1, 2009, electricity distribution rates were rebased using forecast 2009 costs. In accordance with the OEB's plan, the utility will move to a 40 per cent common equity capital structure in 2010. Algoma Power's electricity distribution rates for 2009 were based upon costs derived from a 2007 historical test year. Algoma Power's allowed ROE was 8.57 per cent for 2009 on a deemed capital structure of 50 per cent common equity. In 2008, the OEB approved the use and implementation of the Rural and Remote Rate Protection ("RRRP") subsidy program, which applies to Algoma Power. The RRRP subsidy is calculated as the deficiency between the approved revenue requirement from the OEB and current customer electricity distribution rates, adjusted for the average rate increase across the province of Ontario.

Cornwall Electric is exempt from many aspects of the above Acts and is also subject to a 35-year Franchise Agreement with the City of Cornwall, expiring in 2033. The rate-setting mechanism is subject to a price cap with commodity cost flow through. The base revenue requirement is adjusted annually for inflation, load growth and customer growth.

Belize Electricity

Belize Electricity is regulated by the Public Utilities Commission ("PUC") under the terms of the *Electricity Act* (Belize), the *Electricity (Tariffs, Charges and Quality of Service Standards) By-Laws* (Belize) and the *Public Utilities Commission Act* (Belize). The PUC oversees the rates that may be charged in respect of utility services and the standards that must be maintained in relation to such services, and uses a future test year to set rates. In addition, the PUC is responsible for the award of licences and for monitoring and enforcing compliance with licence conditions. The basic customer electricity rate at Belize Electricity is comprised of two components. The first component is value-added delivery and the second is the cost of fuel and purchased power, including the variable cost of generation, which is a flow through in customer rates. The value-added delivery component of the tariff allows the Company to recover its operating expenses, T&D expenses, taxes and amortization, and an allowed rate of return on rate base assets ("ROA"). Belize Electricity's allowed ROA for 2009 was 10.00 per cent (2008 – 10.00 to 15.00 per cent from January to June 2008 and 10.00 per cent from July 1, 2008).

Caribbean Utilities

Caribbean Utilities has been generating and distributing electricity in its franchise area of Grand Cayman, Cayman Islands, under a licence from the Government of the Cayman Islands since May 10, 1966. Effective January 1, 2008, new licences were granted to Caribbean Utilities. The new exclusive T&D licence is for an initial period of 20 years, expiring April 2028, with a provision for automatic renewal. The new generation licence is for a period of 21.5 years, expiring September 2029. The licences contain the provision for a rate cap and adjustment mechanism ("RCAM") based on published consumer price indices. Customer electricity rates for 2009, effective June 1, were set in accordance with the licences, translating into a targeted allowed ROA range of 9.00 per cent to 11.00 per cent (2008 – 9.00 per cent to 11.00 per cent). The licences detail the role of the Electricity Regulatory Authority, which oversees all licences, establishes and enforces licence standards, reviews the RCAM and annually approves capital expenditures.

Fortis Turks and Caicos

Fortis Turks and Caicos provides electricity to Providenciales, North Caicos and Middle Caicos through PPC and provides electricity to South Caicos through Atlantic for terms of 50 years under licences dated January and October 1987, and November 1986 (collectively, the "Agreements"), respectively. Among other matters, the Agreements describe how electricity rates are to be set by the Government of the Turks and Caicos Islands, using a future test year, in order to provide Fortis Turks and Caicos with an allowed ROA of 17.50 per cent (the "Allowable Operating Profit") based on a calculated rate base, and including interest on the amounts by which actual operating profits fall short of the Allowable Operating Profits on a cumulative basis (the "cumulative shortfall").

Fortis Turks and Caicos makes annual submissions to the Government of the Turks and Caicos Islands calculating the amount of the Allowable Operating Profit and the cumulative shortfall. The submissions for 2009 calculated the Allowable Operating Profit for 2009 to be $24 million (US$21 million) and the cumulative shortfall at December 31, 2009 to be $37 million (US$32 million). Fortis Turks and Caicos has a legal right under the Agreements to request an increase in electricity rates to begin to recover the cumulative shortfall. The recovery would, however, be dependent on future sales volumes and expenses.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term deposits with maturities of three months or less from the date of acquisition.

Inventories

Inventories are valued at the lower of weighted-average cost and net realizable value. When a situation that previously caused inventories to be written down below cost no longer exists, the amount of the write-down is to be reversed.

Effective January 1, 2008, the Corporation adopted CICA Handbook Section 3031, *Inventories*, and inventories of $26 million as at that date were reclassified to utility capital assets from inventories as they were held for the development, construction and maintenance of other utility capital assets.

Utility Capital Assets

Utility capital assets of Newfoundland Power are stated at values approved by the PUB as at June 30, 1966, with subsequent additions at cost. Utility capital assets of Caribbean Utilities are stated on the basis of appraised values as at November 30, 1984, with subsequent additions at cost. Utility capital assets of Fortis Turks and Caicos are stated at appraised values as at September 18, 1986. Subsequent additions are at cost except for the distribution systems on Middle, North and South Caicos, transferred by the Government of the Turks and Caicos Islands to Fortis Turks and Caicos by the Agreements for US$2.00, in aggregate, as valued in the books of the Companies. Utility capital assets of all other utility operations are stated at cost.

Contributions in aid of construction represent amounts contributed by customers and governments for the cost of utility capital assets. These contributions are recorded as a reduction in the cost of utility capital assets and are being reduced annually by an amount equal to the charge for amortization provided on the related assets.

As required by their respective regulator, amortization expense at FortisAlberta, Newfoundland Power and Maritime Electric includes an amount allowed for regulatory purposes to provide for future asset removal and site restoration costs, net of salvage proceeds. The amount provided for in amortization expense is recorded as a long-term regulatory liability. Actual asset removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. As at December 31, 2009, the long-term regulatory liability for future asset removal and site restoration costs was $326 million (December 31, 2008 – $325 million) (Note 4 *(xvi)*).

As permitted by the regulator, the Terasen Gas companies and FortisBC record actual asset removal and site restoration costs, net of salvage proceeds, against accumulated amortization. Prior to the fourth quarter of 2009, FortisBC had estimated an amount within amortization expense to represent a provision for future asset removal and site restoration costs. Based on new information that became available to the Company in late 2009, FortisBC now believes the portion of amortization expense and the related accumulated amortization that had previously been estimated as relating to the provisioning of future asset removal and site restoration costs is more appropriately presented and disclosed as accumulated amortization rather than as a provision for future asset removal and site restoration costs in regulatory liabilities. This presentation provides more reliable and relevant information about the effects of regulation on FortisBC (Note 30).

Effective January 1, 2010, as required by the regulator, the Terasen Gas companies are to record actual asset removal and site restoration costs, net of salvage proceeds, as operating expenses to be recovered from customers in current rates. Any difference between forecast net asset removal and site restoration costs used to set customer rates and actual net costs are subject to deferral account treatment.

FortisOntario, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos record asset removal and site restoration costs in earnings in the period incurred. These costs did not have a material impact on the Corporation's 2009 and 2008 earnings.

Upon retirement or disposal of utility capital assets, the capital cost of the assets is charged to accumulated amortization by the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, Belize Electricity and, commencing May 2008, Caribbean Utilities, as required by their respective regulator, with no loss, if any, reflected in earnings. It is expected that any loss charged to accumulated amortization will be reflected in future amortization expense when it is collected in customer gas and electricity rates. At FortisOntario and Fortis Turks and Caicos, any remaining net book value, less salvage proceeds, upon retirement or disposal of utility capital assets is recorded immediately in earnings. In the absence of rate regulation, any loss on the retirement or disposal of utility capital assets at the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, Belize Electricity and Caribbean Utilities would be recognized in the current period. The loss charged to accumulated amortization in 2009 was approximately $37 million (2008 – $36 million).

Utility capital assets include inventories held for the development, construction and maintenance of other utility capital assets. When put into service, the inventories are amortized using the straight-line method based on the estimated service lives of the capital assets to which they are added.

Maintenance and repairs of utility capital assets are charged to earnings in the period incurred, while replacements and betterments are capitalized.

As required by their respective regulator, the Terasen Gas companies, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity, Fortis Turks and Caicos and, commencing May 2008, Caribbean Utilities capitalize overhead costs that are not directly attributable to specific utility capital assets but which relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulator. In the absence of rate regulation, only those overhead costs directly attributable to construction activity would be capitalized. The general expenses capitalized ("GEC") are allocated over constructed capital assets and amortized over their estimated service lives. In 2009, GEC totalled $57 million (2008 – $57 million).

2. Summary of Significant Accounting Policies (cont'd)

Utility Capital Assets (cont'd)

As required by their respective regulator, the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, Belize Electricity and, commencing May 2008, Caribbean Utilities include an equity component in the allowance for funds used during construction ("AFUDC"), which is included in the cost of utility capital assets. Since AFUDC includes both an interest component and an equity component, it exceeds the amount allowed to be capitalized in similar circumstances by entities not subject to rate regulation. AFUDC is deducted from finance charges and AFUDC capitalized during 2009 was $18 million (2008 – $13 million) (Note 18), including an equity component of $9 million (2008 – $6 million). AFUDC is charged to operations through amortization expense over the estimated service lives of the applicable utility capital assets.

FortisAlberta maintains a regulatory tax basis adjustment account, which represents the excess of the deemed tax basis of the Company's utility capital assets for regulatory rate-making purposes as compared to the Company's tax basis for income tax purposes. The regulatory tax basis adjustment is being amortized over the estimated service lives of the Company's utility capital assets by an offset against the provision for amortization. The regulatory tax basis adjustment is recorded as a reduction in utility capital assets. During 2009, amortization expense was reduced by $4 million (2008 – $4 million) for the amortization of the regulatory tax basis adjustment.

Utility capital assets are being amortized using the straight-line method based on the estimated service lives of the capital assets. Amortization rates range from 0.4 per cent to 33.3 per cent. The composite rate of amortization before reduction for amortization of contributions in aid of construction for 2009 was 3.2 per cent (2008 – 3.5 per cent). The service life ranges and average remaining service life of the Corporation's distribution, transmission, generation and other assets as at December 31 were as follows.

	2009		2008	
(Years)	**Service Life Ranges**	**Average Remaining Service Life**	Service Life Ranges	Average Remaining Service Life
Distribution				
Gas	**10–50**	**34**	10–50	34
Electricity	**5–75**	**26**	5–75	28
Transmission				
Gas	**10–50**	**33**	10–50	34
Electricity	**10–75**	**34**	10–75	34
Generation	**5–75**	**31**	5–75	31
Other	**5–70**	**13**	5–70	12

Income Producing Properties

Income producing properties of Fortis Properties, which include office buildings, shopping malls, hotels, land and related equipment and tenant inducements, are recorded at cost. Buildings are being amortized using the straight-line method over an estimated useful life of 60 years. Fortis Properties amortizes tenant inducements over the initial terms of the leases to which they relate. The lease terms vary to a maximum of 20 years. Equipment is recorded at cost and is amortized on a straight-line basis over a range of 2 years to 25 years.

Maintenance and repairs of income producing properties are charged to earnings in the period incurred, while replacements and betterments are capitalized.

Leases

Leases that transfer to the Corporation substantially all of the risks and benefits incidental to ownership of the leased item are capitalized at the present value of the minimum lease payments. Capital leases are depreciated over the lease term. Operating lease payments are recognized as an expense in earnings on a straight-line basis over the lease term.

Intangibles

Effective January 1, 2009, the Corporation retroactively adopted the new CICA Handbook Section 3064, *Goodwill and Intangible Assets.* This Section, which replaces Section 3062, *Goodwill and Other Intangible Assets*, and Section 3450, *Research and Development Costs*, establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. As at December 31, 2008, the impact of retroactively adopting Section 3064 was a reclassification of $264 million to intangible assets and related decreases of $262 million to utility capital assets, $1 million to income producing properties and $1 million to other assets due to the reclassification of the net book value of land, transmission and water rights, computer software costs, franchise costs, customer contracts and other costs.

Intangible assets are comprised of computer software costs; land, transmission and water rights; franchise fees; customer contracts; and assets under construction. Intangible assets are recorded at cost less accumulated depreciation.

The useful lives of intangible assets are assessed to be either finite or indefinite. Intangible assets with finite lives are amortized over their useful life and assessed for impairment whenever there is an indication that the intangible asset may be impaired. Amortization rates for regulated intangible assets are approved by the respective regulator and, for non-regulated intangible assets, require the use of estimates of the useful lives of the assets.

Intangible assets are derecognized on disposal or when no future economic benefits are expected from their use. Upon retirement or disposal of intangibles, the capital cost of the assets is charged to accumulated amortization by the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, Belize Electricity and, commencing May 2008, Caribbean Utilities, as required by their respective regulator, with no loss, if any, reflected in earnings. It is expected that any loss charged to accumulated amortization will be reflected in future amortization expense when it is collected in customer gas and electricity rates. At FortisOntario and Fortis Turks and Caicos, any remaining net book value, less salvage proceeds, upon retirement or disposal of intangible assets is recorded immediately in earnings. In the absence of rate regulation, any loss on the retirement or disposal of intangibles at the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, Belize Electricity and Caribbean Utilities would be recognized in the current period. The loss charged to accumulated amortization in 2009 was approximately $1 million (2008 – nil).

Intangible assets with indefinite useful lives are tested for impairment annually either individually or at the reporting unit level. Such intangibles are not amortized. The useful life of an intangible asset with an indefinite useful life is reviewed annually to determine whether the indefinite life assessment continues to be supportable. If not, the change in the useful life assessment from indefinite to finite is made on a prospective basis.

Intangible assets are being amortized using the straight-line method based on the estimated service lives of the assets. Amortization rates range from 1.6 per cent to 20.0 per cent. The service life ranges and average remaining service life of definite life intangibles as at December 31, 2009 were as follows.

(Years)	**Service Life Ranges**	**Average Remaining Service Life**
Computer software	5–10	5
Land, transmission and water rights	15–61	37
Franchise fees, customer contracts and other	4–40	6

Impairment of Long-Lived Assets

The Corporation reviews the valuation of utility capital assets, income producing properties, intangible assets with finite lives and other long-term assets when events or changes in circumstances indicate that the asset's carrying value exceeds the total undiscounted cash flows expected from its use and eventual disposition. An impairment loss, calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques, is recognized in earnings in the period in which it is identified. There was no impact on the consolidated financial statements as a result of asset impairments for the years ended December 31, 2009 and 2008.

The process for asset-impairment testing differs for non-regulated generation assets compared to regulated utility assets. Since each non-regulated generating facility provides an individual cash inflow stream, such an asset is tested individually and an impairment is recorded if the future cash inflows are no longer sufficient to recover the carrying value of the generating facility. Asset-impairment testing at the regulated utilities is carried out at the enterprise level to determine if assets are impaired. The recovery of a regulated asset's carrying value, including a fair rate of return on capital or assets, is provided through customer gas and electricity rates approved by the respective regulatory authority. The cash inflows for regulated enterprises are not asset-specific but are pooled for the entire regulated enterprise.

Goodwill

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any previous amortization and any write-down for impairment. The Corporation is required to perform an annual impairment test and any impairment provision is charged to earnings. During 2009, Fortis changed the date of the annual goodwill impairment test from July 31 to October 1 to better correspond with the timing of the preparation of the Corporation's and subsidiaries' annual financial budgets. Accordingly, this accounting change is preferable in the Corporation's circumstance. The change in timing of the test did not delay, accelerate or avoid any impairment charge. The Corporation performed the annual goodwill impairment test as at July 31, 2009 and again as at October 1, 2009. The change in the timing of the impairment test had no impact on the 2009 consolidated financial statements.

To assess for impairment, the fair value of each of the Corporation's reporting units is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities

2. Summary of Significant Accounting Policies (cont'd)

Goodwill (cont'd)

from the fair value of the reporting unit to determine the implied fair value of goodwill, and then by comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value of the goodwill is the impairment amount. In addition to the annual impairment test, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. No goodwill impairment provision has been determined for the years ended December 31, 2009 and 2008.

Employee Future Benefits

Defined Benefit and Defined Contribution Pension Plans

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, defined contribution pension plans and group Registered Retirement Savings Plans ("RRSPs") for its employees. The costs of the defined contribution pension plans and RRSPs are expensed as incurred. The accrued pension benefit obligation and the value of pension cost of the defined benefit pension plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of the discount rate, expected plan investment performance, salary escalation and retirement ages of employees.

With the exception of the Terasen Gas companies and Newfoundland Power, pension plan assets are valued at fair value. At the Terasen Gas companies and Newfoundland Power, plan assets are valued using the market-related value, where investment returns in excess of or below expected returns are recognized in the asset value over a period of three years.

The excess of any cumulative net actuarial gain (loss) over 10 per cent of the greater of the benefit obligation and the fair value of plan assets (the market-related value of plan assets at the Terasen Gas companies and Newfoundland Power) at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

On January 1, 2000, Newfoundland Power prospectively adopted CICA Handbook Section 3461, *Employee Future Benefits*. The Company is amortizing the resulting transitional obligation on a straight-line basis over 18 years, the expected average remaining service period of the plan members at that time.

As approved by the regulator, the cost of defined benefit pension plans at FortisAlberta is being recovered in customer rates based on the cash payments made.

Any difference between pension cost recognized under Canadian GAAP and that recovered from customers in current rates for defined benefit and defined contribution pension plans, which is expected to be recovered, or refunded, in future customer rates, is subject to deferral treatment (Note 4 *(xi)*).

Supplementary and Other Post-Employment Benefit ("OPEB") Plans

The Corporation, the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and FortisOntario also offer other non-pension post-employment benefits through defined benefit plans, including certain health and dental coverage, for qualifying members.

Additionally, the Corporation, the Terasen Gas companies, FortisAlberta, Newfoundland Power and Maritime Electric provide retirement allowances and supplemental retirement plans for certain of its executive employees. The accrued benefit obligation and the value of the cost associated with the supplementary and OPEB plans are actuarially determined using the projected benefits method prorated on service and best-estimate assumptions. The excess of any cumulative net actuarial gain (loss) over 10 per cent of the benefit obligation at the beginning of the fiscal year, and any unamortized past service costs are deferred and amortized over the average remaining service period of active employees.

As approved by the respective regulator, the cost of OPEB plans at FortisAlberta and Newfoundland Power are recovered in customer rates based on the cash payments made. The cost of supplemental pension plans at FortisAlberta is also recovered in customer rates based on the cash payments made.

Any difference between the cost recognized under Canadian GAAP and that recovered from customers in current rates for OPEB and supplemental pension plans, which is expected to be recovered or refunded in future customer rates, is subject to deferral treatment (Note 4 *(v)*).

Stock-Based Compensation

The Corporation records compensation expense upon the issuance of stock options granted under its 2002 Stock Option Plan ("2002 Plan") and 2006 Stock Option Plan ("2006 Plan") (Note 16). Compensation expense is measured at the date of grant using the Black-Scholes fair value option-pricing model and is amortized over the four-year vesting period of the options granted, with stock option forfeitures recognized in the period incurred. The offsetting entry is an increase to contributed surplus for an amount equal to the annual compensation expense related to the issuance of stock options. Upon exercise, the proceeds of the options are credited to capital stock at the option prices and the fair value of the options, as previously recorded, is reclassified from contributed surplus to capital stock. An exercise of options below the current market price has a dilutive effect on capital stock and shareholders' equity.

The Corporation also records compensation expense associated with its Directors' Deferred Share Unit ("DSU") and Performance Share Unit ("PSU") Plans using the fair value method, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU and PSU liabilities is based on the Corporation's common share closing price at the end of each reporting period.

Foreign Currency Translation

The assets and liabilities of foreign operations, all of which are self-sustaining and denominated in US dollars or in a currency pegged to the US dollar, are translated at the exchange rate in effect at the balance sheet date. Belize Electricity's reporting currency is the Belizean dollar, while the reporting currency of Caribbean Utilities, FortisUS Energy, BECOL and Fortis Turks and Caicos is the US dollar. The Belizean dollar is pegged to the US dollar at BZ$2.00=US$1.00. The exchange rate in effect as at December 31, 2009 was US$1.00=CDN$1.05 (December 31, 2008 – US$1.00=CDN$1.22). The resulting unrealized translation gains and losses are accumulated as a separate component of shareholders' equity within accumulated other comprehensive loss and the current period change is recorded in other comprehensive income. Revenue and expense items are translated at the average exchange rate in effect during the period.

Foreign exchange translation gains and losses on foreign currency-denominated long-term debt that is designated as an effective hedge of foreign net investments are recorded separately in other comprehensive income.

Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate prevailing at the balance sheet date. Revenue and expense items denominated in foreign currencies are translated at the exchange rate prevailing at the transaction date. Gains and losses on translation are recorded in earnings.

Financial Instruments

The Corporation designates its financial instruments into one of the following five categories: (i) held for trading; (ii) available for sale; (iii) held to maturity; (iv) loans and receivables; or (v) other financial liabilities. All financial instruments are initially measured at fair value. Financial instruments classified as held for trading or available for sale are subsequently measured at fair value, with any change in fair value recorded in earnings and other comprehensive income, respectively. All other financial instruments are subsequently measured at amortized cost.

Derivative financial instruments, including derivative features embedded in financial instruments or other contracts that are not considered closely related to the host financial instrument or contract, are generally classified as held for trading and, therefore, must be measured at fair value with changes in fair value recorded in earnings. If a derivative financial instrument is designated as a hedging item in a qualifying cash flow hedging relationship, the effective portion of changes in fair value is recorded in other comprehensive income. Any change in fair value relating to the ineffective portion is recorded immediately in earnings. At the Terasen Gas companies, any difference between the amount recognized upon a change in the fair value of a derivative financial instrument, whether or not designated in a qualifying hedging relationship, and the amount recovered from customers in current rates is subject to regulatory deferral treatment to be recovered from, or refunded to, customers in future rates (Note 4 *(ii)* and *(xxi)*). Generally, the Corporation limits the use of derivative financial instruments to those that qualify as hedges, as discussed under "Hedging Relationships".

The Corporation has selected January 1, 2003 as the transition date for recognizing embedded derivatives and, therefore, recognizes as separate assets and liabilities only those derivatives embedded in hybrid instruments issued, acquired or substantially modified on or after January 1, 2003. While some of the Corporation's long-term debt contracts have prepayment options that qualify as embedded derivatives to be separately recorded, none have been recorded as they are immaterial to the Corporation's consolidated results of operations and financial position.

The Corporation's policy is to recognize transaction costs associated with financial assets and liabilities that are classified as other than held for trading as adjustments to the cost of those financial assets and liabilities recorded on the consolidated balance sheet. These transaction costs are amortized to earnings using the effective interest rate method over the life of the related financial instrument.

Effective for the first quarter of 2009, the Corporation adopted the new Emerging Issues Committee Abstract 173 ("EIC-173"), *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*. EIC-173 requires that the Corporation's own credit risk and the credit risk of its counterparties be taken into account in determining the fair value of a financial instrument. There was no material effect on the Corporation's consolidated financial statements as a result of adopting EIC-173.

Effective December 31, 2009, the Corporation adopted amendments to the CICA Handbook Section 3862, *Financial Instruments – Disclosures*, by providing additional disclosures about the fair value measurement of financial instruments and enhanced liquidity risk disclosures. The amendments establish a hierarchical disclosure framework associated with the level of pricing observability utilized in measuring fair value.

2. *Summary of Significant Accounting Policies (cont'd)*

Financial Instruments (cont'd)

This framework defines three levels of inputs to the fair value measurement process and requires that each fair value measurement be assigned to a level corresponding to the lowest level input that is significant to the fair value measurement in its entirety.

The three broad levels of inputs defined by the hierarchy in Section 3862 are as follows:

i) Level 1 Inputs – quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date;

ii) Level 2 Inputs – inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly, as prices, or indirectly, as derived from prices; and

iii) Level 3 Inputs – inputs for the asset or liability that are not based on observable market data (unobservable inputs). These unobservable inputs reflect the entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability and are developed based on the best information available in the circumstances, which might include the reporting entity's own data.

The Corporation has reflected the additional disclosures in Note 25.

Effective January 1, 2008, the Corporation adopted CICA Handbook Section 3862, *Financial Instruments – Disclosures*, and Section 3863, *Financial Instruments – Presentation*, which require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks from financial instruments to which the Corporation is exposed. The disclosures are provided in Notes 25 and 26.

Hedging Relationships

As at December 31, 2009, the Corporation's hedging relationships consisted of an interest rate swap contract, a foreign exchange forward contract, natural gas derivatives and US dollar borrowings. Derivative financial instruments are used only to manage risk and are not used for trading purposes.

Fortis Properties has designated its interest rate swap contract as a hedge of the cash flow risk related to floating-rate long-term debt. The interest rate swap contract is valued at the present value of future cash flows based on published forward future interest rate curves. The fair value and subsequent changes in fair value of the interest rate swap contract that is in an effective hedging relationship is recorded in other comprehensive income.

The foreign exchange forward contract is held by TGVI and hedges the cash flow risk related to approximately US$15 million remaining to be paid under a contract for the construction of a liquefied natural gas ("LNG") storage facility. The fair value of the foreign exchange forward contract is calculated using the present value of cash flows based on a market foreign exchange rate and the foreign exchange forward rate curve. Any change in the fair value of the foreign exchange forward contract is deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator.

The natural gas derivatives are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts at the Terasen Gas companies have floating, rather than fixed, prices. The fair value of the natural gas derivatives is calculated using the present value of cash flows based on market prices and forward curves for the commodity cost of natural gas.

The fair value of the foreign exchange forward contract and the natural gas derivatives are estimates of the amounts that the Terasen Gas companies would have to receive or pay if forced to settle all outstanding contracts as at the balance sheet date. As at December 31, 2009, none of the natural gas derivatives were designated as hedges of the natural gas supply contracts. However, any changes in the fair value of the natural gas derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator.

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. The Corporation has designated its corporately held US dollar long-term debt as a hedge of the foreign exchange risk related to its net investments in self-sustaining foreign subsidiaries. The unrealized foreign exchange gains and losses on the US dollar-denominated long-term debt and the partially offsetting unrealized foreign exchange losses and gains on the foreign net investments are recognized in other comprehensive income.

Income Taxes

Effective January 1, 2009, Fortis retroactively recognized future income tax assets and liabilities and related regulatory liabilities and assets, without prior period restatement, for the amount of future income taxes expected to be refunded to, or recovered from, customers in future gas and electricity rates. Prior to January 1, 2009, the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power used the taxes payable method of accounting for income taxes. The effect on the Corporation's consolidated financial statements, as at January 1, 2009, of adopting amended Section 3465, *Income Taxes*, included an increase in total future income tax liabilities and total future income tax assets of $491 million and $24 million, respectively; an increase in regulatory assets and regulatory liabilities of $535 million and $59 million, respectively; and a combined $9 million net increase in income taxes payable, deferred credits, other assets, utility capital assets and goodwill associated with the reclassification of future income taxes that were previously netted against these respective balance sheet items. Included in future income tax assets and liabilities recorded are the future income tax effects of the subsequent settlement of the related regulatory assets and liabilities through customer rates.

The Corporation and its subsidiaries follow the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are likely to be realized. The future income tax assets and liabilities are measured using the enacted or substantively enacted income tax rates and laws that will be in effect when the differences are expected to be recovered or settled. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in earnings in the period that the change occurs. Current income tax expense (recovery) is recognized for the estimated income taxes payable (receivable) in the current year.

As approved by the respective regulator, the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power and FortisOntario recover income tax expense in customer rates based only on income taxes that are currently payable for regulatory purposes, except for certain deferral accounts specifically prescribed by the respective regulator. Therefore, current customer rates do not include the recovery of future income taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in rates when they become payable. The above utilities recognize an offsetting regulatory asset or liability for the amount of income taxes that are expected to be collected in rates once they become payable.

Any difference between the expense recognized under Canadian GAAP and that recovered from customers in current rates for income tax expense that is expected to be recovered, or refunded, in future customer rates is subject to deferral treatment (Note 4 *(i)*).

Belize Electricity is subject to corporate tax; however, it is capped at 1.75 per cent of gross revenue. Caribbean Utilities and Fortis Turks and Caicos are not subject to income tax as they operate in tax-free jurisdictions. BECOL is not subject to income tax as it was granted tax-exempt status by the Government of Belize for the terms of its 50-year power purchase agreements.

The Corporation does not provide for income taxes on undistributed earnings of foreign subsidiaries that are not expected to be repatriated in the foreseeable future.

Revenue Recognition

Revenue at the Corporation's regulated utilities is recognized in a manner approved by each utility's regulatory authority. Revenue at the regulated utilities is billed at rates approved by the applicable regulatory authority and is generally bundled to include service associated with generation, transmission and distribution, except at FortisAlberta and FortisOntario.

Transmission is the conveyance of gas at high pressures (generally at 2,070 kilopascals ("kPa") and higher) and electricity at high voltages (generally at 69 kilovolts ("kV") and higher). Distribution is the conveyance of gas at lower pressures (generally below 2,070 kPa) and electricity at lower voltages (generally below 69 kV). Distribution networks convey gas and electricity from transmission systems to end-use customers.

As required by the respective regulatory authority, revenue from the sale of gas by the Terasen Gas companies and electricity by FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities and Fortis Turks and Caicos is recognized on an accrual basis. Gas and electricity are metered upon delivery to customers and recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of each period, a certain amount of consumed gas and electricity will not have been billed. Gas and electricity consumed but not yet billed to customers are estimated and accrued as revenue at each period end.

As required by the PUC, revenue from the sale of electricity by Belize Electricity is recognized as monthly billings are issued to customers. In the absence of rate regulation, revenue would be recorded on an accrual basis. The difference between recognizing revenue on a billed versus an accrual basis is recorded on the consolidated balance sheet as a regulatory liability (Note 4 *(xviii)*).

FortisAlberta reports revenue and expenses related to transmission services on a net basis in revenue. As stipulated by the AUC, FortisAlberta is required to arrange and pay for transmission services with the Alberta Electric System Operator ("AESO") and collect transmission revenue from its customers, which is achieved through invoicing the customers' retailers through FortisAlberta's transmission component of its AUC-approved rates. FortisAlberta is solely a distribution company and, as such, does not operate or provide any transmission or generation services. The Company is a conduit for the flow through of transmission costs to end-use customers, as the transmission provider does not have a direct relationship with these customers. The rates collected are based on forecasted transmission expenses and, for certain elements

2. *Summary of Significant Accounting Policies (cont'd)*

Revenue Recognition (cont'd)

of the transmission costs, FortisAlberta is subject to the risk of actual expenses being different from the forecast revenue relating to transmission services. All other differences are subject to deferral treatment and are either recovered, or refunded, in future customer rates (Note 4 *(iv)*).

FortisOntario's regulated operations primarily comprise the operations of Cornwall Electric, Canadian Niagara Power and Algoma Power. Electricity rates at Cornwall Electric are bundled due to the nature of the Franchise Agreement with the City of Cornwall. Electricity rates at Canadian Niagara Power and Algoma Power are not bundled. At Canadian Niagara Power and Algoma Power, the cost of power and/or transmission are a flow through to customers, and costs and revenue associated with the recovery of these costs are tracked and recorded separately. This treatment is consistent with other regulated utilities in Ontario, as required under OEB regulation. The amount of transmission revenue tracked separately at Canadian Niagara Power is not significant in relation to the consolidated revenue of Fortis.

All of the Corporation's non-regulated generation operations record revenue on an accrual basis and revenue is recognized on delivery of output at rates fixed under contract or based on observed market prices as stipulated in contractual arrangements. Generally, production from the Corporation's generation facilities is metered at or near month end and production data is used to record revenue earned.

Hospitality revenue is recognized when services are provided. Real estate revenue is derived from leasing retail and office space to tenants for varying periods of time. Revenue is recorded in the month that it is earned at rates in accordance with lease agreements.

The leases are primarily of a net nature, with tenants paying basic rental plus a pro rata share of certain defined overhead expenses. Certain retail tenants pay additional rent based on a percentage of the tenant's sales. Expenses recovered from tenants are recorded as revenue. The escalation of lease rates included in long-term leases is recorded in earnings using the straight-line method over the term of the lease.

Asset-Retirement Obligations ("AROs")

AROs, including conditional AROs, are recorded as a liability at fair value, with a corresponding increase to utility capital assets or income producing properties. The Corporation recognizes AROs in the periods in which they are incurred if a reasonable estimate of fair value can be determined.

The Corporation has AROs associated with hydroelectric generation facilities, interconnection facilities and wholesale energy supply agreements. While each of the foregoing will have legal AROs, including land and environmental remediation and/or removal of assets, the final date and cost of remediation and/or removal of the related assets cannot be reasonably determined at this time.

No significant environmental issues have been identified with respect to the Corporation's hydroelectric generation and T&D assets. These assets are reasonably expected to operate in perpetuity due to the nature of their operation. The licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the assets and ensure the continued provision of service to customers. In the event that environmental issues are identified, assets are decommissioned or the applicable licences, permits or agreements are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

The Corporation also has AROs associated with the removal of certain electricity distribution system assets from rights-of-way at the end of the life of the system. As it is expected that the system will be in service indefinitely, an estimate of the fair value of asset removal costs cannot be reasonably determined at this time.

The Corporation has determined that AROs may exist regarding the remediation of certain land. Certain leased land contains assets integral to operations and it is reasonably expected that the land-lease agreement will be renewed indefinitely; therefore, an estimate of the fair value of remediation costs cannot be reasonably determined at this time. Certain other land may require environmental remediation but the amount and nature of the remediation is indeterminable at this time. AROs associated with land remediation will be recorded when the timing, nature and amount of costs can be reasonably estimated.

Capital Disclosures

Effective January 1, 2008, the Corporation adopted CICA Handbook Section 1535, *Capital Disclosures*, which requires the Corporation to disclose additional information about its capital and the manner in which it is managed. The additional disclosure includes quantitative and qualitative information regarding the Corporation's objectives, policies and processes for managing capital. The disclosures are provided in Note 24.

Use of Accounting 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 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.

The Corporation's critical accounting estimates are described above in Note 2 under the headings Regulation, Utility Capital Assets, Income Producing Properties, Intangibles, Goodwill, Employee Future Benefits, Income Taxes, Revenue Recognition and AROs, and in Notes 4 and 28.

3. Future Accounting Changes

International Financial Reporting Standards ("IFRS")

In October 2009, the AcSB issued a third and final Omnibus Exposure Draft confirming that publicly accountable enterprises in Canada will be required to apply IFRS, in full and without modification, beginning January 1, 2011. The Corporation's expected IFRS transition date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported on the Corporation's consolidated opening IFRS balance sheet as at January 1, 2010 and amounts reported by the Corporation for the year ended December 31, 2010.

In July 2009, CICA Handbook Section 1506, *Accounting Changes*, was modified such that it does not apply to changes in accounting policies upon the complete replacement of an entity's primary basis of accounting. The requirement for all publically accountable enterprises in Canada to apply IFRS, beginning January 1, 2011, represents a complete replacement of the Corporation's primary basis of accounting. CICA Handbook Section 1506, therefore, does not apply to the adoption of IFRS.

Fortis is continuing to assess the financial reporting impacts of adopting IFRS. In July 2009, the International Accounting Standards Board ("IASB") issued the Exposure Draft – *Rate-Regulated Activities*. Based on the Exposure Draft as it currently exists, regulatory assets and liabilities arising from activities subject to cost of service regulation would be recognized under IFRS when certain conditions are met. The ability to record regulatory assets and liabilities, as proposed, should reduce the earnings' volatility at the Corporation's regulated utilities that may otherwise result under IFRS in the absence of an accounting standard for rate-regulated activities, but will result in the requirement to provide enhanced balance sheet presentation and note disclosures. However, uncertainty as to the final outcome of this Exposure Draft and the final standard on accounting for rate-regulated activities under IFRS has resulted in the Corporation being unable to reasonably estimate and conclude on the impact on the Corporation's future consolidated financial position and results of operations with respect to the differences, if any, in accounting for rate-regulated activities under IFRS versus Canadian GAAP.

Fortis anticipates a change in the manner in which it will measure and recognize the value of its income producing properties and a significant increase in disclosure resulting from the adoption of IFRS. The Corporation is identifying and assessing the impact of this change in valuation and additional disclosure requirements, as well as implementing systems changes that will be necessary to compile the required disclosures.

The IASB's project schedule had indicated that a final standard on rate-regulated activities would be released in the second quarter of 2010. Commentary received on the Exposure Draft, and the resulting activities now planned by the IASB, creates uncertainty as to if and when a final standard will be released. If a final standard is released, it may not be until late 2011.

Business Combinations

In January 2009, the AcSB issued new CICA Handbook Section 1582, *Business Combinations*, together with Section 1601, *Consolidated Financial Statements*, and Section 1602, *Non-Controlling Interests*. These new standards are effective for fiscal years beginning on or after January 1, 2011 with early adoption permitted. The Corporation has chosen to early adopt the above standards as at January 1, 2010. As a result of adopting Section 1582, changes in the determination of the fair value of the assets and liabilities of the acquiree will result in a different calculation of goodwill with respect to future acquisitions. Such changes include the expensing of acquisition-related costs incurred during a business acquisition, rather than recording them as a capital transaction, and the disallowance of recording restructuring accruals by the acquirer. The adoption of Section 1582 will affect the recognition of business combinations completed by the Corporation on or after January 1, 2010 and, as a result, may have a material impact on the Corporation's consolidated earnings and financial position.

Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The adoption of Sections 1601 and 1602 will result in non-controlling interests being presented as components of equity, rather than as liabilities, on the consolidated balance sheet. Also, net earnings and components of other comprehensive income attributable to the owners of the parent and to the non-controlling interests are required to be separately disclosed on the statement of earnings. The adoption of Sections 1601 and 1602 is not expected to have a material impact on the Corporation's consolidated earnings, cash flows or financial position.

4. Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process at the Corporation's regulated utilities. Regulatory assets represent future revenues associated with certain costs incurred that will be, or are expected to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process.

All amounts deferred as regulatory assets and liabilities are subject to regulatory approval. As such, the regulatory authorities could alter the amounts subject to deferral, at which time the change would be reflected in the consolidated financial statements. Certain remaining recovery and settlement periods are those expected by management and the actual recovery or settlement periods could differ based on regulatory approval.

Based on previous, existing or expected future regulatory orders or decisions, the Corporation's regulated utilities have recorded the following amounts expected to be recovered from, or refunded to, customers in future periods.

Regulatory Assets *(in millions)*	**2009**	2008	**Remaining recovery period *(Years)***
Future income taxes *(i)*	**$ 560**	$ –	To be determined
Rate stabilization accounts – Terasen Gas companies *(ii)*	**82**	76	Various
Rate stabilization accounts – electric utilities *(iii)*	**68**	80	Various
AESO charges deferral *(iv)*	**80**	64	2
Regulatory OPEB plan asset *(v)*	**59**	51	To be determined
Point Lepreau [(1)] replacement energy deferral (*vi*)	**23**	-	25
Income taxes recoverable on OPEB plans *(vii)*	**18**	18	To be determined
Energy management costs *(viii)*	**9**	7	1–7
Deferred development costs for capital *(ix)*	**7**	5	1–26
Southern Crossing Pipeline tax reassessment *(x)*	**7**	7	To be determined
Deferred pension costs *(xi)*	**6**	7	6
Lease costs *(xii)*	**6**	6	14–29
Deferred capital asset amortization *(xiii)*	**4**	8	1
Residential unbundling *(xiv)*	**3**	7	1
Other regulatory assets *(xv)*	**49**	24	To be determined
Total regulatory assets	**981**	360	
Less: current portion	**(223)**	(157)	1
Long-term regulatory assets	**$ 758**	$ 203	

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

Regulatory Liabilities *(in millions)*	**2009**	2008	**Remaining settlement period *(Years)***
Future asset removal and site restoration provision *(xvi)*	**$ 326**	$ 325	To be determined
Future income taxes *(i)*	**35**	–	To be determined
Rate stabilization accounts – Terasen Gas companies *(ii)*	**44**	32	1–3
Rate stabilization accounts – electric utilities *(iii)*	**21**	9	1
PBR incentive liabilities *(xvii)*	**15**	13	1–2
Unbilled revenue liability *(xviii)*	**10**	15	To be determined
Southern Crossing Pipeline deferral *(xix)*	**9**	9	1–5
Deferred interest *(xx)*	**7**	3	1–3
Fair value of the foreign exchange forward contract *(xxi)*	**–**	7	To be determined
Other regulatory liabilities *(xxii)*	**22**	21	To be determined
Total regulatory liabilities	**489**	434	
Less: current portion	**(53)**	(45)	1
Long-term regulatory liabilities	**$ 436**	$ 389	

Description of the Nature of Regulatory Assets and Liabilities

(i) *Future Income Taxes*

Effective January 1, 2009, Fortis retroactively recognized future income tax assets and liabilities and related regulatory liabilities and assets, without prior period restatement, for the amount of future income taxes expected to be refunded to, or recovered from, customers in future gas and electricity rates. Prior to January 1, 2009, the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power used the taxes payable method of accounting for income taxes. Included in future income tax assets and liabilities recorded are the future income tax effects of the subsequent settlement of the related regulatory assets and liabilities through customer rates. The regulatory asset and liability balances are expected to be recovered from, or refunded to, customers in future rates when the future taxes become payable or receivable. In the absence of rate regulation, future income taxes would have been recorded in earnings as incurred. The regulatory balances related to future income taxes are not subject to a regulatory return.

(ii) *Rate Stabilization Accounts – Terasen Gas Companies*

The rate stabilization accounts at the Terasen Gas companies are amortized and recovered through customer rates as approved by the BCUC. The rate stabilization accounts mitigate the effect on earnings of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather and natural gas cost volatility.

At TGI, a Revenue Stabilization Adjustment Mechanism ("RSAM") accumulates the margin impact of variations in the actual versus forecast gas volumes consumed by residential and commercial customers. Additionally, a Commodity Cost Reconciliation Account ("CCRA") and a Midstream Cost Reconciliation Account ("MCRA") accumulate differences between actual natural gas costs and forecast natural gas costs as recovered in base rates. The CCRA also accumulates the changes in fair value of TGI's natural gas commodity derivative instruments. At TGVI, a Gas Cost Variance Account ("GCVA") is used to mitigate the effect on TGVI's earnings of natural gas cost volatility. The GCVA also accumulates the changes in fair value of TGVI's natural gas commodity derivative instruments.

The RSAM is anticipated to be refunded through rates over a three-year period. The MCRA, CCRA and GCVA accounts are anticipated to be fully recovered within the next fiscal year. In the absence of rate regulation, the amounts in the rate stabilization accounts would not be deferred but would be recorded in earnings as incurred. The recovery or refund of the rate stabilization accounts is dependent on actual natural gas consumption volumes and on annually approved customer rates.

TGVI also maintains a Revenue Deficiency Deferral Account ("RDDA") to accumulate unrecovered costs of providing service to customers or to draw down such costs where earnings exceed the allowed ROE as set by the BCUC. During 2009, the RDDA balance was fully recovered as achieved earnings exceeded the allowed ROE. The additional recovery of the RDDA balance was recorded in the Revenue Surplus Account ("RSA"), which captured the revenue surplus that was created during 2009. The BCUC approved the balance in the RSA account as at December 31, 2009 at a forecasted amount. The difference between the actual 2009 revenue surplus and the approved forecasted amount was transferred to the Rate Stabilization Deferral Account ("RSDA"), subject to BCUC approval. The RSA will be returned to customers equally in 2010 and 2011. The RSDA will be refunded to customers in rates in 2012 and beyond, subject to regulatory approval.

The rate stabilization accounts at the Terasen Gas companies are detailed as follows.

(in millions)	**2009**	2008
Current Regulatory Assets		
CCRA	**$ 40**	$ 54
MCRA	**29**	–
GCVA	**13**	19
RDDA	**–**	3
	$ 82	$ 76
Current Regulatory Liabilities		
RSAM	**$ 12**	$ –
RSA	**2**	–
MCRA	**–**	24
	$ 14	$ 24
Long-Term Regulatory Liabilities		
RSAM	**$ 23**	$ 8
RSA	**2**	–
RSDA	**5**	–
	$ 30	$ 8

4. *Regulatory Assets and Liabilities (cont'd)*

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(iii) Rate Stabilization Accounts – Electric Utilities

The rate stabilization accounts associated with the Corporation's regulated electric utilities (Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos) are recovered or refunded through customer rates, as approved by the respective regulatory authority. The rate stabilization accounts primarily mitigate the effect on earnings of the variability in the cost of fuel and/or purchased power above or below a forecast or predetermined level. Additionally, at Newfoundland Power, the PUB has ordered the provision of a weather normalization account to adjust for the effect of variations in weather conditions when compared to long-term averages. The weather normalization account reduces Newfoundland Power's year-to-year earnings volatility that would otherwise result from fluctuations in revenue and purchased power. The recovery period of the rate stabilization accounts, with the exception of Newfoundland Power's weather normalization account, ranges from one year to five years and is subject to periodic review by the respective regulator.

The balance in Newfoundland Power's weather normalization account as at December 31, 2009 was $6 million (December 31, 2008 – $6 million). The account balance should approach zero over time because it is based on long-term averages for weather conditions. As ordered by the PUB, approximately $7 million of the weather normalization account is to be amortized equally over 2008 through 2012. In the absence of rate regulation, the fluctuations in revenue and purchased power would be recorded in earnings as incurred. The recovery period of the remaining balance of the weather normalization account is yet to be determined as it depends on weather conditions in the future.

As at December 31, 2009, $10 million in pre-2004 costs deferred in the Energy Cost Adjustment Mechanism ("ECAM") account at Maritime Electric remained to be amortized. As approved by IRAC, the remaining amount is to be amortized and collected from customers at a rate of $2 million per year over a recovery period of five years. Annual deferral of energy costs to the ECAM account is recovered from, or refunded to, customers, as approved by IRAC, over a rolling 12-month period.

As at December 31, 2009, the $20 million balance in Belize Electricity's rate stabilization account was in a payable position (December 31, 2008 – $9 million payable position) and was not subject to a regulatory return. In 2008, an unfavourable $18 million adjustment was made to Belize Electricity's rate stabilization account reflecting, in substance, the disallowance of previously incurred fuel and purchased power costs as a result of the Final Decision by the PUC on Belize Electricity's 2008/2009 Rate Application.

As at December 31, 2009, $6 million (December 31, 2008 – $2 million) of the remaining balance of the rate stabilization accounts in a receivable position was not subject to a regulatory return. In the absence of rate regulation, the cost of fuel and/or purchased power would be expensed in the period incurred.

(iv) AESO Charges Deferral

FortisAlberta maintains an AESO charges deferral account that represents expenses incurred in excess of revenue collected for various items, such as transmission costs incurred and flowed through to customers, that are subject to deferral to be collected in future customer rates. As at December 31, 2009, the AESO charges deferral account balance of $80 million is expected to be collected in customer rates in 2010 and 2011, with $20 million of the balance subject to regulatory approval. In the absence of rate regulation, the costs would be expensed in the period incurred and no deferral treatment would be permitted.

(v) Regulatory OPEB Plan Asset

At FortisAlberta and Newfoundland Power, and prior to 2005 at FortisBC, the cash cost of providing OPEB plans is collected in customer rates as permitted by the respective regulator. Effective 2005, as permitted by the BCUC, the recovery from customers of the cost of OPEB plans at FortisBC is based on cash costs plus a partial recovery of the full accrual cost of the OPEB plans. The regulatory OPEB asset represents the deferred portion of the benefit cost at FortisAlberta, FortisBC and Newfoundland Power that is expected to be recovered from customers in future rates. In the absence of rate regulation, the benefit cost would be recognized on an accrual basis as actuarially determined, with no deferral of costs recorded on the consolidated balance sheet. As at December 31, 2009, FortisAlberta's and FortisBC's regulatory OPEB assets totalling $12 million (December 31, 2008 – $11 million) were not subject to a regulatory return.

(vi) Point Lepreau Nuclear Generating Station Replacement Energy Deferral

Maritime Electric has regulatory approval to defer the cost of replacement energy related to the New Brunswick Power ("NB Power") Point Lepreau Nuclear Generating Station ("Point Lepreau") during its refurbishment outage. The station was out of service in 2009 due to the refurbishment occurring during the year. The balance in the regulatory asset account is expected to be recovered from customers over 25 years, the remaining life of the station, subject to regulatory approval. In the absence of rate regulation, the costs would be expensed in the period incurred and no deferral treatment would be permitted.

(vii) Income Taxes Recoverable on OPEB Plans

At TGI, the regulator allows OPEB plan costs to be collected in customer gas rates on an accrual basis, rather than on a cash basis, which creates timing differences for income tax purposes. Prior to 2009, TGI accounted for income taxes using the taxes payable basis of accounting; the tax effect of this timing difference is deferred as a regulatory asset and will be reduced as cash payments for OPEB plans exceed required accruals and amounts collected in customer gas rates. In the absence of rate regulation, the income tax would not be deferred.

(viii) Energy Management Costs

FortisBC and Maritime Electric provide energy management services to promote energy efficiency programs to their customers. FortisBC and Maritime Electric, as required by their respective regulator, have capitalized related expenditures and are amortizing these expenditures on a straight-line basis over seven and five years, respectively. This regulatory asset represents the unamortized balance of the energy management costs. In the absence of rate regulation, the costs of the energy management services would have been expensed in the period incurred.

(ix) Deferred Development Costs for Capital

Deferred development costs for capital projects include costs for projects under development at the Terasen Gas companies that are subject to regulatory approval for recovery in customer rates. The majority of the balance relates to costs incurred on the conversion of TGWI customer appliances from propane to natural gas. A provision of approximately $6 million for costs incurred on the conversion in excess of the amounts approved by the regulator was charged to earnings in 2009. In the absence of rate regulation, the deferred development costs would be capitalized; however, the ultimate period of amortization may differ.

(x) Southern Crossing Pipeline Tax Reassessment

The Southern Crossing Pipeline tax reassessment deferral relates to an assessment of additional British Columbia Social Services Tax, for which TGI has filed an appeal. Depending on the success of the appeal, TGI will either be refunded the balance or, alternatively, expects to recover the costs from customers in future rates. In the absence of rate regulation, the payment would continue to be recorded as a receivable, pending resolution of the appeal. Any final assessed tax, upon resolution of the appeal, would be expensed in the period in which it becomes known (Note 28).

(xi) Deferred Pension Costs

Deferred pension costs are incremental pension costs arising from Newfoundland Power's 2005 Early Retirement Program that were deferred and are being amortized over a ten-year period that began on April 1, 2005, as ordered by the PUB. In the absence of rate regulation, these costs would have been expensed in 2005.

(xii) Lease Costs

FortisBC defers lease costs associated with the Brilliant Terminal Station ("BTS") and Trail office building. The recovery of the capital cost of the BTS, the cost of financing the BTS obligation and the related operating costs are not being fully recovered by FortisBC in current customer rates since those rates include only the BTS lease payments on a cash basis. The regulatory asset balance represents the deferred portion of the cost of the lease that is expected to be recovered from customers in future rates. In the absence of rate regulation, these costs would be expensed in the period incurred.

FortisBC is accounting for the lease of the Trail office building as an operating lease. The terms of the agreement require increasing step lease payments during the lease term; however, as ordered by the BCUC, FortisBC recovers the Trail office lease payments from customers and records the lease costs on a cash basis. This regulatory asset represents the deferred portion of the lease payments that is expected to be recovered from customers in future rates as the stepped lease payments increase. In the absence of rate regulation, these costs would be recorded in earnings on a straight-line basis over the lease term.

The deferred lease costs are not subject to a regulatory return.

(xiii) Deferred Capital Asset Amortization

Newfoundland Power deferred the recovery of a $6 million increase in capital asset amortization in each of 2006 and 2007, in accordance with a PUB order. The amount deferred is being amortized as an increase in amortization costs and included in customer rates equally over 2008 through 2010. In the absence of rate regulation, the deferral of the capital asset amortization would not have been recorded.

(xiv) Residential Unbundling

Residential unbundling costs are related to costs incurred by TGI to develop a third-party marketer alternative for residential customers to purchase natural gas from suppliers other than TGI. The BCUC approved the deferral of these costs and the recovery of these costs over a three-year period. The remaining balance will be recovered from customers in 2010. In the absence of rate regulation, these costs would have been expensed in the period incurred.

(xv) Other Regulatory Assets

Other regulatory assets relate to the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, FortisOntario, Maritime Electric and Caribbean Utilities. The balance is comprised of various items each individually less than $5 million. As at December 31, 2009, $33 million of the balance was approved for recovery from customers in future rates, with the remaining balance expected to be approved. As at December 31, 2009, $9 million (December 31, 2008 – $1 million) of the balance was not subject to a regulatory return. In the absence of rate regulation, the deferrals would not be permitted.

December 31, 2009 and 2008

4. Regulatory Assets and Liabilities (cont'd)

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(xvi) Future Asset Removal and Site Restoration Provision

As required by the respective regulator, this regulatory liability represents amounts collected in customer electricity rates over the life of certain utility capital assets at FortisAlberta, Newfoundland Power and Maritime Electric attributable to asset removal and site restoration costs that are expected to be incurred in the future. As required by the respective regulator, amortization rates at FortisAlberta, Newfoundland Power and Maritime Electric include an amount allowed for regulatory purposes to provide for these future asset removal and site restoration costs, net of salvage proceeds. Actual asset removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred.

The regulatory liability represents the amount of expected future asset removal and site restoration costs associated with utility capital assets in service as at the balance sheet date, calculated using current amortization rates as approved by the respective regulator. Any difference between actual costs incurred and those assumed in the collected amounts, and any cumulative adjustments resulting from changes to the regulator-approved amortization rates at which these costs are collected, are reflected in the regulatory liability, with the offset recorded as an adjustment to accumulated amortization.

During 2009, the amount included in amortization expense associated with the provision for future asset removal and site restoration costs was $29 million (2008 – $27 million). During 2009, actual asset removal and site restoration costs, net of salvage proceeds, were $23 million (2008 – $16 million). In the absence of rate regulation, asset removal and site restoration costs, net of salvage proceeds, would have been recognized in earnings as incurred rather than provided for over the life of the assets through amortization expense.

(xvii) PBR Incentive Liabilities

TGI and FortisBC's regulatory frameworks include PBR mechanisms that allow for the recovery from, or refund to, customers of a portion of certain increased or decreased costs, as compared to the forecast costs used to set customer rates. The final disposition of amounts deferred as regulatory PBR incentive assets and liabilities is determined under the PBR mechanisms as approved per BCUC orders (Note 2). TGI's regulatory PBR incentive liability of $11 million is expected to be refunded to customers during 2010 and 2011. The current portion of FortisBC's regulatory PBR incentive liability has been approved by the BCUC for settlement in 2010. In the absence of rate regulation, the regulatory PBR incentive amounts would not be recorded.

(xviii) Unbilled Revenue Liability

Belize Electricity and, prior to 2006, Newfoundland Power record revenue derived from electricity sales on a billed basis (Note 2). The difference between revenue recognized on a billed basis and revenue recognized on an accrual basis is recorded on the consolidated balance sheet as a regulatory liability. Effective January 1, 2006, Newfoundland Power prospectively changed its revenue recognition policy to an accrual basis, as approved by the PUB. As a result, the $24 million cumulative difference between billed revenue as of December 31, 2005 and revenue that would have been recognized on an accrual basis was recorded as a regulatory liability. As ordered by the PUB, Newfoundland Power amortized $5 million of this regulatory liability in 2009 (2008 – $7 million). The remaining unamortized $5 million balance as at December 31, 2009 will be amortized in 2010. In the absence of rate regulation, revenue would be recorded on an accrual basis and the deferral of unbilled revenue would not have been permitted. Belize Electricity's unbilled revenue liability of $5 million as at December 31, 2009 (December 31, 2008 – $6 million) was not subject to a regulatory return and the settlement period has not yet been determined.

(xix) Southern Crossing Pipeline Deferral

This regulatory liability represents the difference between actual revenue received from third parties for the use of the Southern Crossing Pipeline and what has been approved in revenue requirements. The deferral is amortized over a period of five years and $2 million as at December 31, 2009 (December 31, 2008 – nil) was not subject to a regulatory return. In the absence of rate regulation, the revenue would be recognized when services are rendered.

(xx) Deferred Interest

The Terasen Gas companies have interest deferral mechanisms, as approved by the BCUC, which accumulate variances between the actual and approved interest rates associated with long-term and short-term borrowings and between the actual and forecasted interest calculated on the average balance of the MCRA account. The deferred interest will be refunded to customers in future rates over one to three years. In the absence of rate regulation, the actual costs would have been expensed in the period incurred.

(xxi) Fair Value of the Foreign Exchange Forward Contract

This regulatory liability captures the change in the fair value of the foreign exchange forward contract, which hedges the US dollar payments required under the LNG construction contract. As at December 31, 2009, the balance of this deferral was $0.2 million. In the absence of rate regulation, the change in fair value of the foreign exchange forward contract would be recorded in earnings in the period incurred. This regulatory deferral is not subject to a regulatory return.

(xxii) *Other Regulatory Liabilities*

Other regulatory liabilities relate to the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power and FortisOntario. The balance is comprised of various items each individually less than $5 million. As at December 31, 2009, $11 million of the balance was approved for refund to customers or reduction in future rates, with the remaining balance expected to be approved. As at December 31, 2009, $10 million (December 31, 2008 – $7 million) of the balance was not subject to a regulatory return. In the absence of rate regulation, the deferrals would not be permitted.

Financial Statement Effect of Rate Regulation

In the absence of rate regulation and, therefore, in the absence of recording regulatory assets and liabilities as described above, the total impact on the consolidated financial statements would have been as follows:

	Increase/(Decrease)	
(in millions)	**2009**	2008
Regulatory assets	**$ (954)**	$ (344)
Regulatory liabilities	**(489)**	(446)
Accumulated other comprehensive loss	**30**	18
Opening retained earnings	**(378)**	65
Revenue	**$ 451**	$ 609
Energy supply costs	**447**	540
Operating expense	**122**	74
Amortization expense	**(35)**	(31)
Finance charges	**(3)**	–
Corporate taxes	**7**	(11)
Net earnings	**$ (87)**	$ 37

5. Inventories

(in millions)	**2009**	2008
Gas in storage	**$ 159**	$ 212
Materials and supplies	**19**	17
	$ 178	$ 229

During 2009, inventories of $1,022 million (2008 – $1,268 million) were expensed and reported in energy supply costs in the consolidated statement of earnings. Inventories expensed to operating expenses were $14 million for 2009 (2008 – $14 million), which included $10 million for food and beverage costs at Fortis Properties (2008 – $9 million).

6. Other Assets

(in millions)	**2009**	2008
Deferred pension costs *(Note 20)*	**$ 139**	$ 128
Exploits Partnership capital assets *(Note 28)*	**–**	61
Long-term accounts receivable (due 2040)	**9**	9
Deferred recoverable and project costs	**–**	8
Corporate income tax deposit at Maritime Electric *(Note 28)*	**6**	6
Energy management loans	**4**	5
Other assets	**16**	13
	$ 174	$ 230

Energy management loans to residential and general service customers for energy-efficiency initiatives and related products are interest bearing and range in terms from one year to ten years.

The other assets are recorded at cost and are recovered or amortized over the estimated period of future benefit.

7. Utility Capital Assets

2009 *(in millions)*	**Cost**	**Accumulated Amortization**	**Contributions in Aid of Construction (Net)**	**Regulatory Tax Basis Adjustment (Net)**	**Net Book Value**
Distribution					
Gas	**$ 2,407**	**$ (438)**	**$ (182)**	**$ –**	**$ 1,787**
Electricity	**4,369**	**(1,163)**	**(503)**	**(83)**	**2,620**
Transmission					
Gas	**1,311**	**(353)**	**(84)**	**–**	**874**
Electricity	**994**	**(259)**	**(18)**	**–**	**717**
Generation	**982**	**(281)**	**–**	**–**	**701**
Other	**938**	**(348)**	**(13)**	**–**	**577**
Assets under construction	**324**	**–**	**–**	**–**	**324**
Land	**87**	**–**	**–**	**–**	**87**
	$ 11,412	**$ (2,842)**	**$ (800)**	**$ (83)**	**$ 7,687**

2008 *(in millions)*	Cost	Accumulated Amortization	Contributions in Aid of Construction (Net)	Regulatory Tax Basis Adjustment (Net)	Net Book Value
Distribution					
Gas	$ 2,334	$ (415)	$ (180)	$ –	$ 1,739
Electricity	3,936	(1,051)	(490)	(87)	2,308
Transmission					
Gas	1,243	(314)	(100)	–	829
Electricity	939	(250)	(3)	–	686
Generation	957	(276)	(1)	–	680
Other	874	(335)	(13)	–	526
Assets under construction	304	–	(11)	–	293
Land	80	–	–	–	80
	$ 10,667	$ (2,641)	$ (798)	$ (87)	$ 7,141

Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kPa). These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment. Electricity distribution assets are those used to distribute electricity at lower voltages (generally below 69 kV). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Gas transmission assets are those used to transport natural gas at higher pressures (generally at 2,070 kPa and higher). These assets include transmission stations, telemetry, transmission pipe and other related equipment. Electricity transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and higher). These assets include poles, wires, switching equipment, transformers, support structures and other related equipment.

Generation assets are those used to generate electricity. These assets include hydroelectric and thermal generation stations, gas and combustion turbines, dams, reservoirs and other related equipment.

Other assets include buildings, equipment, vehicles, inventory and information technology assets.

The cost of utility capital assets under capital lease as at December 31, 2009 was $57 million (December 31, 2008 – $56 million) and related accumulated amortization was $24 million (December 31, 2008 – $24 million).

8. Income Producing Properties

2009

(in millions)	**Cost**	**Accumulated Amortization**	**Net Book Value**
Buildings	**$ 490**	**$ (60)**	**$ 430**
Equipment	**70**	**(29)**	**41**
Tenant inducements	**25**	**(17)**	**8**
Land	**64**	**–**	**64**
Assets under construction	**16**	**–**	**16**
	$ 665	**$ (106)**	**$ 559**

2008

(in millions)	Cost	Accumulated Amortization	Net Book Value
Buildings	$ 485	$ (51)	$ 434
Equipment	55	(23)	32
Tenant inducements	24	(14)	10
Land	61	–	61
Assets under construction	3	–	3
	$ 628	$ (88)	$ 540

The cost of income producing property assets under capital lease as at December 31, 2009 was nil (December 31, 2008 – $1 million) and related accumulated amortization was nil (December 31, 2008 – $0.1 million).

9. Intangible Assets

2009

(in millions)	**Cost**	**Accumulated Amortization**	**Net Book Value**
Computer software	**$ 314**	**$ (155)**	**$ 159**
Land, transmission and water rights	**146**	**(37)**	**109**
Franchise fees, customer contracts and other	**16**	**(8)**	**8**
Assets under construction	**3**	**–**	**3**
	$ 479	**$ (200)**	**$ 279**

2008

(in millions)	Cost	Accumulated Amortization	Net Book Value
Computer software	$ 302	$ (143)	$ 159
Land, transmission and water rights	125	(34)	91
Franchise fees, customer contracts and other	16	(5)	11
Assets under construction	12	–	12
	$ 455	$ (182)	$ 273

Additions to intangible assets during 2009 were $33 million, approximately $11 million of which were developed internally. Included in cost and accumulated amortization was $15 million and $1 million, respectively, related to Algoma Power, which was acquired by the Corporation in October 2009. During 2009, fully amortized computer software of $24 million was retired, reducing cost and accumulated amortization.

Included in the cost of land, transmission and water rights as at December 31, 2009 was $66 million (December 31, 2008 – $65 million) not subject to amortization.

10. Goodwill

(in millions)	2009	2008
Balance, beginning of year	**$ 1,575**	$ 1,544
Terasen Gas companies	**6**	(4)
Step acquisition of Caribbean Utilities	**1**	6
Foreign currency translation impacts	**(22)**	29
Balance, end of year	**$ 1,560**	$ 1,575

During 2009, the Terasen Gas companies recognized an adjustment to goodwill associated with the adoption of amended Section 3465, *Income Taxes*, effective January 1, 2009.

During 2008, the Terasen Gas companies recognized the benefit of tax losses that related to periods prior to the Corporation's ownership of Terasen, resulting in a reduction in goodwill.

Goodwill associated with the acquisitions of Caribbean Utilities and Fortis Turks and Caicos is denominated in US dollars, as the reporting currency of these companies is the US dollar. Foreign currency translation impacts are the result of the translation of US dollar-denominated goodwill and the impact of the movement of the Canadian dollar relative to the US dollar.

11. Long-Term Debt and Capital Lease Obligations

(in millions)	Maturity Date	2009	2008
Regulated Utilities			
Terasen Gas Companies			
Secured Purchase Money Mortgages –			
10.71% weighted average fixed rate (2008 – 10.71%)	2015–2016	**$ 275**	$ 275
Unsecured Debentures –			
6.12% weighted average fixed rate (2008 – 6.29%)	2029–2039	**1,420**	1,380
Government loan *(Note 27)*	2010	**4**	8
Obligations under capital leases	2012	**11**	10
FortisAlberta			
Senior Unsecured Debentures –			
5.74% weighted average fixed rate (2008 – 5.61%)	2014–2047	**934**	709
FortisBC			
Secured Debentures –			
9.12% weighted average fixed rate (2008 – 9.28%)	2012–2023	**40**	44
Unsecured Debentures –			
6.00% weighted average fixed rate (2008 – 6.06%)	2014–2047	**500**	445
Obligation under capital lease	2032	**26**	26
Newfoundland Power			
Secured First Mortgage Sinking Fund Bonds –			
7.67% weighted average fixed rate (2008 – 7.84%)	2014–2039	**469**	409
Maritime Electric			
Secured First Mortgage Bonds –			
8.10% weighted average fixed rate (2008 – 8.10%)	2010–2038	**152**	152
FortisOntario			
Senior Unsecured Notes – 7.09% fixed rate	2018	**52**	52
Belize Electricity (Note 24)			
Secured:			
US RBTT Merchant Bank loan – 5.75% to 8.15% fixed rate	2010–2012	**2**	5
Unsecured:			
BZ Debentures –			
10.35% weighted average fixed rate (2008 – 10.35%)	2012–2027	**36**	42
Other loans – 5.23% weighted average fixed rate (2008 – 5.81%)	2015	**7**	11
Other variable interest rate loans	2010–2015	**13**	18

(in millions)	Maturity Date	**2009**	2008
Caribbean Utilities			
US Unsecured Senior Loan Notes –			
6.31% weighted average fixed rate (2008 – 6.04%)	2010–2024	**$ 203**	$ 204
Fortis Turks and Caicos			
Unsecured:			
US Scotiabank (Turks and Caicos) Ltd. loan –			
3.90% weighted average fixed and variable rate (2008 – 3.91%)	2013–2016	**10**	14
US First Caribbean International Bank loan – 5.65% fixed rate	2015	**3**	4
Non-Regulated – Fortis Generation			
Secured:			
Mortgage – 9.44% fixed rate	2013	**4**	5
Exploits Partnership term loan – 7.55% fixed rate			
(non-recourse to Fortis) *(Note 28)*	2028	**–**	61
Non-Regulated – Fortis Properties			
Secured:			
First mortgages –			
6.89% weighted average fixed rate (2008 – 7.02%)	2010–2017	**193**	212
Senior notes – 7.32% fixed rate	2019	**15**	16
Unsecured:			
Non-revolving variable interest rate credit facilities	2010	**3**	7
Corporate – Fortis and Terasen			
Unsecured:			
Debentures –			
6.44% weighted average fixed rate (2008 – 6.37%)	2010–2039	**426**	226
US Senior Notes –			
6.23% weighted average fixed rate (2008 – 6.23%)	2014–2037	**368**	426
US Subordinated Convertible Debentures –			
5.50% weighted average fixed rate (2008 – 5.50%)	2016	**39**	44
Capital Securities – 8.00% fixed rate	2040	**126**	129
Long-term classification of credit facility borrowings *(Note 26)*		**208**	224
Total long-term debt and capital lease obligations		**5,539**	5,158
Less: Deferred financing costs		**(39)**	(34)
Less: Current installments of long-term debt and capital lease obligations		**(224)**	(240)
		$ 5,276	$ 4,884

Certain of the long-term debt instruments held by the Corporation and its subsidiaries are secured, as identified in the table above. When security is provided, it is typically a fixed or floating charge on the specific assets of the company to which the long-term debt is associated.

The purchase money mortgages of the Terasen Gas companies are secured equally and rateably by a first fixed and specific mortgage and charge on TGI's coastal division assets. The aggregate principal amount of the purchase money mortgages that may be used is limited to $425 million.

Repayment of Long-Term Debt and Capital Lease Obligations

The consolidated annual requirements to meet principal repayments and maturities in each of the next five years and thereafter are as follows:

Year	$ millions
2010	224
2011	53
2012	263
2013	99
2014	702
Thereafter	4,198

11. Long-Term Debt and Capital Lease Obligations (cont'd)

Regulated Utilities

FortisBC has a capital lease obligation with respect to the operation of the BTS. Future minimum lease payments associated with this capital lease obligation are approximately $3 million per year over the remaining term of the lease agreement to 2032. The capital lease obligation bears interest at a composite rate of 8.61 per cent.

Belize Electricity's unsecured debentures can be called by the Company at any time after certain dates until maturity by giving holders not more than 60 days' nor less than 30 days' written notice and are repayable at the option of the holders at any time on or after certain dates by giving 12 months' written notice to Belize Electricity. Redemption by agreement between Belize Electricity and the debenture holders at any time is also allowed.

Corporate – Fortis and Terasen

Of the unsecured debentures, $100 million and $200 million are redeemable at the option of Fortis at a price calculated as the greater of the principal amount to be redeemed and an amount equal to the net present value of interest and principal based on the Government of Canada Bond Yield, plus a premium ranging from 0.43% to 0.87%, and 0.65%, respectively, together with accrued and unpaid interest.

The unsecured subordinated convertible debentures, due 2016, are redeemable by Fortis at par at any time on or after November 7, 2011 and are convertible, at the option of the holder, into the Corporation's common shares at $30.59 per share (US$29.11 per share). The debentures are subordinated to all other indebtedness of the Corporation, other than subordinated indebtedness ranking equally to the debentures.

The unsecured subordinated convertible debentures are being accounted for in accordance with their substance and are presented in the consolidated financial statements in their component parts. The liability and equity components are classified separately on the consolidated balance sheet and are measured at their respective fair values at the time of issue. The equity portion of convertible debentures was $5 million as at December 31, 2009 (December 31, 2008 – $6 million).

Terasen may elect to defer payment on the 8.00% capital securities and settle such deferred payments in either cash or common shares of the Company and has the option to settle principal at maturity through the issuance of common shares of the Company. The securities are also exchangeable at the option of the holder on or after April 19, 2010 for common shares of the Company at 90 per cent of the market price, subject to the right of the Company to redeem the securities for cash at par as of the same date.

12. Deferred Credits

(in millions)	**2009**	2008
OPEB plan liabilities *(Note 20)*	**$ 145**	$ 129
Defined benefit liabilities *(Note 20)*	**34**	34
Deferred gains on the sale of natural gas transmission and distribution assets	**42**	46
Deferred payment	**46**	43
Other deferred credits	**28**	25
	$ 295	$ 277

The deferred gains on the sale of natural gas transmission and distribution assets occurred upon the sale and leaseback of pipeline assets to certain municipalities in 2001, 2002, 2004 and 2005. The pre-tax gains of $71 million on combined cash proceeds of $141 million are being amortized over the 17-year terms of the operating leases that commenced at the time of the sale transactions. These operating lease obligations are included in the table in Note 27.

The deferred payment resulted from Terasen's acquisition of TGVI, effective January 1, 2002. The deferred payment has a face value of $52 million but was discounted at May 17, 2007 to its present value. As at December 31, 2009, its present value was $46 million (December 31, 2008 – $43 million). The payment is due on December 31, 2011, or sooner if TGVI realizes revenue from transportation revenue contracts to serve power-generating plants that may be constructed in TGVI's service area. If any part of the deferred payment is paid prior to December 31, 2011, the difference between the payment and the carrying value of the debt will be treated as contingent consideration for the acquisition of TGVI and will be added to the cost of the purchase at that time.

Other deferred credits primarily include customer deposits, funds received in advance of expenditures, DSU and PSU liabilities (Note 16), and unfunded defined contribution pension liabilities. The unfunded defined contribution pension liabilities relate to supplementary employee retirement plans at the Corporation and its Canadian operating subsidiaries for which benefits are based upon employee earnings.

13. Non-Controlling Interest

(in millions)	**2009**	2008
Caribbean Utilities	**$ 77**	$ 92
Belize Electricity	**39**	44
Preference shares of Newfoundland Power	**7**	7
Exploits Partnership *(Note 28)*	**–**	2
	$ 123	$ 145

14. Preference Shares

Authorized

(a) an unlimited number of First Preference Shares, without nominal or par value

(b) an unlimited number of Second Preference Shares, without nominal or par value

Issued and Outstanding		**2009**		2008	
	Classification	**Number of Shares**	**Amount *(in millions)***	Number of Shares	Amount *(in millions)*
First Preference Shares, Series C	Debt	**5,000,000**	**$ 123**	5,000,000	$ 123
First Preference Shares, Series E	Debt	**7,993,500**	**197**	7,993,500	197
Total classified as debt		**12,993,500**	**$ 320**	12,993,500	$ 320
First Preference Shares, Series F	Equity	**5,000,000**	**$ 122**	5,000,000	$ 122
First Preference Shares, Series G	Equity	**9,200,000**	**225**	9,200,000	225
Total classified as equity		**14,200,000**	**$ 347**	14,200,000	$ 347

First Preference Shares Classified as Debt

As the First Preference Shares, Series C and Series E are convertible at the option of the holder into a variable number of common shares of the Corporation based on a market-related price of such common shares, they meet the definition of financial liabilities and, therefore, are classified as long-term liabilities with associated dividends classified as finance charges.

The First Preference Shares, Series C and Series E are entitled to receive fixed cumulative preferential cash dividends at rates of $1.3625 and $1.2250 per share per annum, respectively.

On or after June 1, 2010 and 2013, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series C and Series E, respectively, in whole at any time or in part from time to time, at prices ranging from $25.75 to $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

On or after June 1, 2010 and 2013, the Corporation has the option to convert all, or from time to time any part, of the outstanding First Preference Shares, Series C and Series E, respectively, into fully paid and freely tradable common shares of the Corporation. The number of common shares into which each preference share may be converted will be determined by dividing the then-applicable redemption price per first preference share, together with all accrued and unpaid dividends, by the greater of $1.00 or 95 per cent of the then-current market price of the common shares at such time.

On or after September 1, 2013 and 2016, each First Preference Share, Series C and Series E, respectively, will be convertible at the option of the holder on the first day of September, December, March and June of each year into fully paid and freely tradable common shares of the Corporation, determined by dividing $25.00, together with all accrued and unpaid dividends, by the greater of $1.00 or 95 per cent of the then-current market price of the common shares. If a holder of First Preference Shares, Series C and Series E elects to convert any such shares into common shares, the Corporation can redeem such first preference shares for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares Classified as Equity

In May 2008, the Corporation issued 8 million 5.25% Cumulative Redeemable Five-Year Fixed Rate Reset First Preference Shares, Series G ("First Preference Shares, Series G") and in June 2008 issued an additional 1.2 million First Preference Shares, Series G, following the exercise in full of an over-allotment option in connection with the offering of the 8 million First Preference Shares, Series G. The 9.2 million First Preference Shares, Series G were issued at $25.00 per share for net after-tax proceeds of $225 million.

14. Preference Shares (cont'd)

First Preference Shares Classified as Equity (cont'd)

As the First Preference Shares, Series F and Series G are not redeemable at the option of the holder, they are classified as equity and the associated dividends are deducted on the consolidated statement of earnings immediately before arriving at net earnings applicable to common shares.

The First Preference Shares, Series F are entitled to receive fixed cumulative preferential cash dividends in the amount of $1.2250 per share per annum. The First Preference Shares, Series G are entitled to receive fixed cumulative preferential cash dividends in the amount of $1.3125 per share per annum for each year up to and including August 31, 2013. For each five-year period after this date, the holders of First Preference Shares, Series G are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 2.13%.

On or after December 1, 2011, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series F, in whole at any time or in part from time to time, at prices ranging from $26.00 to $25.00 per share plus all accrued and unpaid dividends. On September 1, 2013 and on September 1 every five years thereafter, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series G, in whole at any time or in part from time to time, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

15. Common Shares

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

Issued and Outstanding	**2009**		2008	
	Number of Shares	**Amount *(in millions)***	Number of Shares	Amount *(in millions)*
Common shares	**171,256,432**	**$ 2,497**	169,190,917	$ 2,449

Common shares issued during the year were as follows:

Issued and Outstanding	**2009**		2008	
	Number of Shares	**Amount *(in millions)***	Number of Shares	Amount *(in millions)*
Balance, beginning of year	**169,190,917**	**$ 2,449**	155,521,313	$ 2,126
Public offering	**–**	**–**	11,700,000	291
Conversion of debentures	**–**	**–**	1,041,871	11
Consumer Share Purchase Plan	**56,648**	**2**	88,686	2
Dividend Reinvestment Plan	**1,203,661**	**29**	230,601	6
Employee Share Purchase Plan	**321,081**	**8**	272,095	7
Stock Option Plans	**484,125**	**9**	336,351	6
Balance, end of year	**171,256,432**	**$ 2,497**	169,190,917	$ 2,449

In December 2008, Fortis issued 11.7 million common shares for $25.65 per share. The common share issue resulted in gross proceeds of approximately $300 million, or approximately $291 million net of after-tax expenses.

During 2008, holders of the Corporation's former 6.75% and 5.50% unsecured subordinated convertible debentures converted approximately US$11 million of the debentures into approximately 1 million common shares of the Corporation.

As at December 31, 2009, 7.2 million (December 31, 2008 – 9.8 million) common shares remained reserved for issuance under the terms of the above-noted share purchase, dividend reinvestment and stock option plans. The Corporation amended and restated its Dividend Reinvestment Plan to provide a 2 per cent discount on the purchase of common shares issued from treasury, with reinvested dividends, effective March 1, 2009.

As at December 31, 2009, common shares reserved for issuance under the terms of the Corporation's convertible debentures and preference shares were 1.4 million and 26 million, respectively (December 31, 2008 – 1.4 million and 26 million, respectively).

As at December 31, 2009, $3 million (December 31, 2008 – $3 million) of common share equity had not been fully paid relating to amounts outstanding under employee share purchase and executive stock option loans.

Earnings per Common Share

The Corporation calculates earnings per common share on the weighted average number of common shares outstanding. The weighted average number of common shares outstanding was 170.2 million for 2009 and 157.4 million for 2008.

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

Earnings per common share were as follows:

	2009			2008		
	Earnings *(in millions)*	**Weighted Average Shares** *(in millions)*	**Earnings per Common Share**	Earnings *(in millions)*	Weighted Average Shares *(in millions)*	Earnings per Common Share
Basic Earnings per Common Share	**$ 262**	**170.2**	**$ 1.54**	$ 245	157.4	$ 1.56
Effect of Potential Dilutive Securities:						
Stock Options	**–**	**0.7**		–	1.0	
Preference Shares *(Notes 14 and 18)*	**17**	**13.9**		17	13.9	
Convertible Debentures	**2**	**1.4**		2	1.4	
	281	**186.2**		264	173.7	
Deduct Anti-Dilutive Impacts:						
Convertible Debentures	**(2)**	**(1.4)**		–	–	
Diluted Earnings per Common Share	**$ 279**	**184.8**	**$ 1.51**	$ 264	173.7	$ 1.52

16. Stock-Based Compensation Plans

Stock Options

The Corporation is authorized to grant officers and certain key employees of Fortis and its subsidiaries options to purchase common shares of the Corporation. As at December 31, 2009, the Corporation had the following stock option plans: 2006 Plan, 2002 Plan and Executive Stock Option Plan. The 2002 Plan was adopted at the Annual and Special General Meeting on May 15, 2002 to ultimately replace the Executive and the former Directors' Stock Option Plans. The Executive Stock Option Plan will cease to exist when all outstanding options are exercised or expire in or before 2011. The 2006 Plan was approved at the May 2, 2006 Annual Meeting at which Special Business was conducted. The 2006 Plan will ultimately replace the 2002 Plan. The 2002 Plan will cease to exist when all outstanding options are exercised or expire in or before 2016. The Corporation has ceased to grant options under the Executive Stock Option Plan and 2002 Plan and all new options are being granted under the 2006 Plan.

Options granted under the 2006 Plan have a maximum term of seven years and expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant. Directors are not eligible to receive grants of options under the 2006 Plan.

Number of Options	**2009**	2008
Options outstanding, beginning of year	**4,140,462**	3,691,771
Granted	**1,037,156**	827,504
Cancelled	**–**	(42,462)
Exercised	**(484,125)**	(336,351)
Options outstanding, end of year	**4,693,493**	4,140,462
Options vested, end of year	**2,546,159**	2,279,240
Weighted Average Exercise Prices		
Options outstanding, beginning of year	**$ 21.04**	$ 18.86
Granted	**22.29**	28.27
Cancelled	**–**	24.20
Exercised	**16.08**	14.48
Options outstanding, end of year	**21.83**	21.04

December 31, 2009 and 2008

16. Stock-Based Compensation Plans (cont'd)

Stock Options (cont'd)

Details of stock options outstanding and vested as at December 31, 2009 were as follows:

Number of Options Outstanding	Number of Options Vested	Exercise Price	Expiry Date
81,368	81,368	$ 9.57	2011
135,726	135,726	$ 12.03	2012
341,320	341,320	$ 12.81	2013
479,484	479,484	$ 15.28	2014
10,000	10,000	$ 15.23	2014
17,011	17,011	$ 14.55	2014
508,367	508,367	$ 18.40	2015
28,000	28,000	$ 18.11	2015
14,708	14,708	$ 20.82	2015
491,937	359,805	$ 22.94	2016
596,232	298,116	$ 28.19	2014
136,832	68,416	$ 25.76	2014
815,352	203,838	$ 28.27	2015
1,037,156	–	$ 22.29	2016
4,693,493	2,546,159		

The weighted average exercise price of stock options vested as at December 31, 2009 was $19.19.

In March 2009, the Corporation granted 1,037,156 options to purchase common shares under its 2006 Plan at the five-day volume weighted average trading price of $22.29 immediately preceding the date of grant. The fair value of each option granted was $4.10 per option.

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

Dividend yield *(%)*	3.19
Expected volatility *(%)*	24.3
Risk-free interest rate *(%)*	3.75
Weighted average expected life *(years)*	4.5

The Corporation records compensation expense upon the issuance of stock options granted under its 2002 and 2006 Plans. Using the fair value method, the compensation expense is amortized over the four-year vesting period of the options granted. Under the fair value method, compensation expense associated with stock options was $3 million for the year ended December 31, 2009 (2008 – $3 million).

Directors' DSU Plan

In 2004, the Corporation introduced the Directors' DSU Plan as an optional vehicle for directors to elect to receive credit for their annual retainer to a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation. The Corporation may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Effective 2006, directors who are not officers of the Corporation are eligible for grants of DSUs representing the equity portion of directors' annual compensation.

Number of DSUs	**2009**	2008
DSUs outstanding, beginning of year	**100,617**	69,722
Granted	**30,336**	27,224
Granted – notional dividends reinvested	**5,375**	3,671
DSUs paid out	**(19,424)**	–
DSUs outstanding, end of year	**116,904**	100,617

During 2009, 19,424 DSUs were paid out to retired members of the Board of Directors of Fortis at a weighted average price of $26.15 per DSU, for a total of approximately $0.5 million.

For the year ended December 31, 2009, expense of $0.9 million (2008 – $0.2 million) was recorded in relation to the DSU Plan.

PSU Plan

In 2004, the Corporation introduced the PSU Plan, which is included as a component of the long-term incentives awarded only to the President and Chief Executive Officer ("CEO") of the Corporation. Each PSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation.

Number of PSUs	2009	2008
PSUs outstanding, beginning of year	85,547	67,615
Granted	40,000	32,940
Granted – notional dividends reinvested	3,939	3,011
PSUs paid out	(31,353)	(18,019)
PSUs outstanding, end of year	98,133	85,547

In March 2009, 31,353 PSUs at $23.39 per PSU for a total of approximately $0.7 million were paid out to the President and CEO of the Corporation. The payout was made upon the three-year maturation period in respect of the PSU grant made in March 2006 and the President and CEO satisfying the payment requirements as determined by the Human Resources Committee of the Board of Directors of Fortis.

For the year ended December 31, 2009, expense of $0.9 million (2008 – $0.6 million) was recorded in relation to the PSU Plan.

17. Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss includes unrealized foreign currency translation gains and losses, net of hedging activities, gains and losses on cash flow hedging activities and gains and losses on discontinued cash flow hedging activities, as discussed in Note 2.

	2009		
(in millions)	Opening balance January 1	Net change	Ending balance December 31
Unrealized foreign currency translation losses, net of hedging activities and tax	$ (46)	$ (32)	$ (78)
(Losses) gains on derivative instruments designated as cash flow hedges, net of tax	(1)	1	–
Net losses on derivative instruments previously discontinued as cash flow hedges, net of tax	(5)	–	(5)
Accumulated other comprehensive loss	$ (52)	$ (31)	$ (83)

	2008		
(in millions)	Opening balance January 1	Net change	Ending balance December 31
Unrealized foreign currency translation (losses) gains, net of hedging activities and tax	$ (82)	$ 36	$ (46)
Losses on derivative instruments designated as cash flow hedges, net of tax	(1)	–	(1)
Net losses on derivative instruments previously discontinued as cash flow hedges, net of tax	(5)	–	(5)
Accumulated other comprehensive loss	$ (88)	$ 36	$ (52)

During 2009, unrealized foreign currency translation losses of $90 million (2008 – gains of $115 million) were recorded in accumulated other comprehensive loss related to the Corporation's net investment in foreign currency-denominated self-sustaining foreign operations. These unrealized foreign currency translation losses were partially offset by the effective portion of unrealized after-tax gains of $58 million (2008 – after-tax losses of $79 million) related to the translation of corporately held US dollar-denominated long-term debt designated as a foreign currency risk hedge. There was no ineffective portion.

18. Finance Charges

(in millions)		2009		2008
Interest – Long-term debt and capital lease obligations	**$**	**351**	$	336
– Short-term borrowings		**10**		25
AFUDC *(Note 2)*		**(18)**		(13)
Interest earned		**–**		(2)
Dividends on preference shares *(Notes 14 and 15)*		**17**		17
	$	**360**	$	363

19. Corporate Taxes

Prior to January 1, 2009, the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power used the taxes payable method of accounting for income taxes. The effect on the Corporation's consolidated financial statements, as at January 1, 2009, of adopting amended Section 3465, *Income Taxes*, included an increase in total future income tax liabilities and total future income tax assets of $491 million and $24 million, respectively; an increase in regulatory assets and regulatory liabilities of $535 million and $59 million, respectively; and a combined $9 million net increase in income taxes payable, deferred credits, other assets, utility capital assets and goodwill associated with the reclassification of future income taxes that were previously netted against these respective balance sheet items. Included in future income tax assets and liabilities recorded are the future income tax effects of the subsequent settlement of related regulatory assets and liabilities through customer rates.

Future income taxes are provided for temporary differences. Future income tax assets and liabilities comprised the following:

(in millions)		2009		2008
Future income tax liability (asset)				
Utility capital assets	**$**	**514**	$	17
Income producing properties		**26**		26
Regulatory assets		**40**		35
Intangible assets		**8**		3
Other assets		**25**		2
Deferred credits		**(30)**		(14)
Loss carryforwards		**(31)**		(28)
Share issue and debt financing costs		**(2)**		(14)
Unrealized foreign currency translation gains (losses) on long-term debt		**5**		(5)
Regulatory liabilities		**(1)**		–
Net future income tax liability	**$**	**554**	$	22
Current future income tax asset	**$**	**(29)**	$	–
Current future income tax liability		**24**		15
Long-term future income tax asset		**(17)**		(54)
Long-term future income tax liability		**576**		61
Net future income tax liability	**$**	**554**	$	22

The adoption of amended Section 3465, *Income Taxes*, on January 1, 2009 also resulted in additional future income tax expense of $38 million for the year ended December 31, 2009 and an offsetting regulatory adjustment to future income tax expense of the same amount during the year. The regulatory adjustment represents the difference between the future income tax expense recognized under amended Section 3465 and that recovered from customers in rates during the year ended December 31, 2009.

The components of the provision for corporate taxes were as follows:

(in millions)	**2009**	2008
Canadian		
Current taxes	**$ 43**	$ 47
Future income taxes	**42**	16
Less regulatory adjustment	**(38)**	–
	4	16
Total Canadian	**47**	63
Foreign		
Current taxes	**1**	4
Future income taxes	**1**	(2)
Total Foreign	**2**	2
Corporate taxes	**$ 49**	$ 65

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 and non-controlling interest. The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

(in millions, except as noted)	**2009**	2008
Combined Canadian federal and provincial statutory income tax rate	**33.0%**	33.5%
Statutory income tax rate applied to earnings before corporate taxes and non-controlling interest	**113**	113
Preference share dividends	**6**	6
Difference between Canadian statutory rate and rates applicable to foreign subsidiaries	**(16)**	(12)
Difference in Canadian provincial statutory rates applicable to subsidiaries in different Canadian jurisdictions	**(8)**	(6)
Items capitalized for accounting purposes but expensed for income tax purposes	**(38)**	(33)
Difference between capital cost allowance and amounts claimed for accounting purposes	**1**	5
Québec Tax Trust settlement – Terasen [(1)]	**–**	(7)
Pension costs	**(1)**	(2)
Other	**(8)**	1
Corporate taxes	**49**	65
Effective tax rate	**14.4%**	19.3%

[(1)] During 2008, Terasen reached a settlement with Revenu Québec and Canada Revenue Agency related to amounts owing as a result of amended Québec tax legislation. The legislation was passed in 2006 for the purpose of challenging certain interprovincial Canadian tax structures. As a result of the settlement, Terasen recorded an approximate $7.5 million tax reduction in 2008.

As at December 31, 2009, the Corporation had approximately $122 million (December 31, 2008 – $112 million) in non-capital and capital loss carryforwards, of which $16 million (December 31, 2008 – $15 million) has not been recognized in the consolidated financial statements. The non-capital loss carryforwards expire between 2014 and 2029.

20. Employee Future Benefits

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, defined contribution pension plans and group RRSPs for its employees. The Corporation, the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario and Algoma Power also offer OPEB plans for qualifying employees.

For the defined benefit pension plan arrangements, the accrued pension benefit obligation and the market-related value or fair value of plan assets are measured for accounting purposes as at December 31 of each year for the Corporation, the Terasen Gas companies, Newfoundland Power and Caribbean Utilities, and as at September 30 of each year for FortisAlberta, FortisBC, FortisOntario and Algoma Power. The most recent actuarial valuation of the pension plans for funding purposes was as of December 31, 2007 for FortisAlberta and FortisBC; as of December 31, 2006 for FortisOntario; as of December 31, 2008 for the Corporation, Newfoundland Power and Caribbean Utilities; and as of July 1, 2009 for Algoma Power. For the Terasen Gas companies, the most recent actuarial valuations of the pension plans for funding purposes were May 17, 2007 and December 31, 2007. The next required valuations will be, at the latest, three years from the date of the most recent actuarial valuation for each plan.

The Corporation's consolidated defined benefit pension plan asset allocation was as follows:

Plan assets as at December 31

(%)	**2009**	2008
Canadian equities	**47**	42
Fixed income	**39**	44
Foreign equities	**9**	8
Real estate	**5**	6
	100	100

The following is a breakdown of the Corporation's and subsidiaries' defined benefit pension plans and their respective funded or unfunded status:

	2009			2008		
(in millions)	**Accrued Benefit Obligation**	**Plan Assets**	**Net Funded (Unfunded)**	Accrued Benefit Obligation	Plan Assets	Net Funded (Unfunded)
Terasen Gas companies	**$ 282**	**$ 257**	**$ (25)**	$ 253	$ 227	$ (26)
FortisAlberta	**23**	**19**	**(4)**	22	18	(4)
FortisBC	**127**	**100**	**(27)**	117	96	(21)
Newfoundland Power	**222**	**243**	**21**	190	212	22
FortisOntario[1]	**21**	**20**	**(1)**	21	19	(2)
Algoma Power	**17**	**15**	**(2)**	–	–	–
Caribbean Utilities	**5**	**3**	**(2)**	6	3	(3)
Fortis	**4**	**4**	**–**	4	4	–
Total	**$ 701**	**$ 661**	**$ (40)**	$ 613	$ 579	$ (34)

[1] Covers eligible employees of Canadian Niagara Power

	Defined Benefit Pension Plans Funded		Supplementary Defined Benefit Plans Unfunded		OPEB Plans Unfunded	
(in millions)	**2009**	2008	**2009**	2008	**2009**	2008
Change in accrued benefit obligation						
Balance, beginning of year	**$ 613**	$ 667	**$ 41**	$ 44	**$ 169**	$ 189
Liability associated with acquisitions	**17**	–	**–**	–	**4**	–
Current service costs	**11**	16	**1**	1	**4**	4
Employee contributions	**9**	8	**–**	–	**–**	–
Interest costs	**40**	36	**2**	2	**11**	10
Benefits paid	**(34)**	(32)	**(2)**	(2)	**(4)**	(4)
Actuarial loss (gain)	**45**	(80)	**2**	(4)	**16**	(30)
Past service costs/plan amendments	**–**	(2)	**–**	–	**(17)**	–
Balance, end of year	**$ 701**	$ 613	**$ 44**	$ 41	**$ 183**	$ 169
Change in value of plan assets						
Balance, beginning of year	**$ 579**	$ 674	**$ –**	$ –	**$ –**	$ –
Assets associated with acquisitions	**15**	–	**–**	–	**–**	–
Actual return (loss) on plan assets	**71**	(92)	**–**	–	**–**	–
Benefits paid	**(34)**	(32)	**(2)**	(2)	**(4)**	(4)
Employee contributions	**9**	8	**–**	–	**–**	–
Employer contributions	**21**	21	**2**	2	**4**	4
Balance, end of year	**$ 661**	$ 579	**$ –**	$ –	**$ –**	$ –
Funded status						
Deficit, end of year	**$ (40)**	$ (34)	**$ (44)**	$ (41)	**$ (183)**	$ (169)
Unamortized net actuarial loss (gain)	**172**	152	**1**	(1)	**40**	26
Unamortized past service costs	**6**	7	**1**	1	**(17)**	(1)
Unamortized transitional obligation	**7**	7	**1**	2	**15**	15
Employer contributions after measurement date	**1**	1	**–**	–	**–**	–
Accrued benefit asset (liability), end of year	**$ 146**	$ 133	**$ (41)**	$ (39)	**$ (145)**	$ (129)
Deferred pension costs *(Note 6)*	**$ 147**	$ 135	**$ (8)**	$ (7)	**$ –**	$ –
Defined benefit liabilities *(Note 12)*	**(1)**	(2)	**(33)**	(32)	**–**	–
OPEB plan liabilities *(Note 12)*	**–**	–	**–**	–	**(145)**	(129)
	$ 146	$ 133	**$ (41)**	$ (39)	**$ (145)**	$ (129)
Significant assumptions						
Weighted average discount rate during the year *(%)*	**6.62**	5.37	**6.65**	5.35	**6.72**	5.39
Weighted average discount rate as at December 31 *(%)*	**6.16**	6.62	**6.19**	6.65	**6.27**	6.72
Weighted average expected long-term rate of return on plan assets *(%)*	**7.05**	7.24	**–**	–	**–**	–
Weighted average rate of compensation increase *(%)*	**3.60**	3.60	**3.52**	3.48	**3.68**	3.63
Weighted average health-care cost trend increase as at December 31 *(%)*	**–**	–	**–**	–	**6.34**	6.58
Expected average remaining service life of active employees *(years)*	**4–15**	5–12	**3–11**	4–12	**9–17**	9–15

December 31, 2009 and 2008

20. Employee Future Benefits (cont'd)

	Defined Benefit Pension Plans Funded		Supplementary Defined Benefit Plans Unfunded		OPEB Plans Unfunded	
(in millions)	**2009**	2008	**2009**	2008	**2009**	2008
Components of net benefit cost						
Current service costs	**$ 11**	$ 16	**$ 1**	$ 1	**$ 4**	$ 4
Interest costs	**40**	36	**2**	2	**11**	10
Actual (return) loss on plan assets	**(71)**	92	**–**	–	**–**	–
Actuarial loss (gain)	**45**	(80)	**2**	(4)	**16**	(30)
Past service costs/plan amendments	**–**	(2)	**–**	–	**(17)**	–
Costs arising in the year	**25**	62	**5**	(1)	**14**	(16)
Differences between costs arising and costs recognized in the year in respect of:						
Return on plan assets	**25**	(141)	–	–	**–**	–
Actuarial (loss) gain	**(42)**	84	**(2)**	4	**(14)**	34
Past service costs	**1**	3	**–**	1	**16**	–
Transitional obligation and plan amendments	**–**	–	**1**	–	**2**	3
Regulatory adjustment	**1**	1	**–**	–	**(6)**	(7)
Net benefit cost	**$ 10**	$ 9	**$ 4**	$ 4	**$ 12**	$ 14

For 2009, the effects of changing the health-care cost trend rate by 1 per cent were as follows:

(in millions)	1 per cent increase in rate	1 per cent decrease in rate
Increase (decrease) in accrued benefit obligation	**$ 22**	**$ (19)**
Increase (decrease) in current service and interest costs	**2**	**(2)**

The following table provides the sensitivities associated with a 100 basis point move in the expected long-term rate of return on pension plan assets and the discount rate on 2009 net defined benefit pension cost, and the related accrued defined benefit pension asset and liability recorded in the Corporation's consolidated financial statements, as well as the impact on the accrued defined benefit pension obligation.

Increase (Decrease) *(in millions)*	Net Benefit Cost	Accrued Benefit Asset	Accrued Benefit Liability	Accrued Benefit Obligation
Impact of increasing the rate of return assumption by 100 basis points	**$ (7)**	**$ 7**	**$ –**	**$ –**
Impact of decreasing the rate of return assumption by 100 basis points	**7**	**(7)**	**–**	**–**
Impact of increasing the discount rate assumption by 100 basis points	**(3)**	**2**	**(1)**	**(73)**
Impact of decreasing the discount rate assumption by 100 basis points	**6**	**(4)**	**1**	**86**

During 2009, the Corporation expensed $12 million (2008 – $11 million) related to defined contribution pension plans.

21. Business Acquisitions

2009

REGULATED ELECTRIC UTILITY

a. Algoma Power

In October 2009, FortisOntario acquired all of the issued and outstanding common shares of Great Lakes Power Distribution Inc., subsequently renamed Algoma Power, for aggregate cash consideration of approximately $75 million including acquisition costs, initially financed through drawings on the Corporation's committed credit facility.

Algoma Power owns and operates an electric distribution system in an area adjacent to Sault Ste. Marie, Ontario. The acquisition has been accounted for using the purchase method, whereby the financial results of Algoma Power have been included in the consolidated financial statements of Fortis commencing October 2009. The financial results of Algoma Power have been included in the Regulated Electric Utilities – Other Canadian segment.

Algoma Power is regulated by the OEB and, thus, its determination of revenue and earnings is based on regulated rates of return that are applied to historic values, which do not change with a change of ownership. Therefore, for all of the individual assets and liabilities associated with Algoma Power, no fair market value adjustments were recorded as part of the purchase price because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to customers. Accordingly, the book value of the assets and liabilities of Algoma Power has been assigned as fair value for the purchase price allocation.

The following table summarizes the fair value of the assets acquired and liabilities assumed at the date of acquisition.

(in millions)	**Total**
Fair value assigned to net assets:	
Current assets	**$ 9**
Utility capital assets	**49**
Intangible assets	**14**
Regulatory assets	**4**
Other assets	**2**
Current liabilities	**(4)**
Regulatory liabilities	**(1)**
Other liabilities	**(3)**
	70
Cash	**5**
	$ 75

NON-REGULATED FORTIS PROPERTIES

b. Holiday Inn Select Windsor

In April 2009, Fortis Properties purchased the Holiday Inn Select Windsor in Ontario for an aggregate cash purchase price of approximately $7 million, including acquisition costs.

The acquisition has been accounted for using the purchase method, whereby the financial results of the hotel have been consolidated in the financial statements of Fortis commencing April 2009.

The purchase price allocation to assets, based on their fair values, was as follows:

(in millions)	**Total**
Fair value assigned to net assets:	
Income producing properties	**$ 7**

2008

NON-REGULATED FORTIS PROPERTIES

Sheraton Hotel Newfoundland

In November 2008, Fortis Properties purchased the Sheraton Hotel Newfoundland for an aggregate cash purchase price of approximately $22 million, including acquisition costs.

The acquisition has been accounted for using the purchase method, whereby the financial results of the hotel have been consolidated in the financial statements of Fortis commencing November 2008.

The purchase price allocation to assets, based on their fair values, was as follows:

(in millions)	Total
Fair value assigned to net assets:	
Income producing properties	$ 22

December 31, 2009 and 2008

22. Segmented Information

Information by reportable segment is as follows:

	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
Year ended December 31, 2009 *($ millions)*	Terasen Gas Companies – Canadian	Fortis Alberta	Fortis BC	NF Power	Other Canadian[1]	Total Electric Canadian	Electric Caribbean[2]	Fortis Generation[3]	Fortis Properties	Corporate and Other	Inter-segment eliminations	Consolidated
Revenue	1,663	331	253	527	279	1,390	339	39	218	27	(39)	3,637
Energy supply costs	1,022	–	72	346	183	601	192	2	–	–	(18)	1,799
Operating expenses	268	132	70	52	32	286	54	11	146	14	(6)	773
Amortization	102	94	37	46	19	196	37	5	16	8	–	364
Operating income	271	105	74	83	45	307	56	21	56	5	(15)	701
Finance charges	121	50	32	34	19	135	16	2	22	79	(15)	360
Corporate taxes (recoveries)	33	(5)	5	16	6	22	2	3	10	(21)	–	49
Non-controlling interest	–	–	–	1	–	1	11	–	–	–	–	12
Net earnings (loss)	117	60	37	32	20	149	27	16	24	(53)	–	280
Preference share dividends	–	–	–	–	–	–	–	–	–	18	–	18
Net earnings (loss) applicable to common shares	117	60	37	32	20	149	27	16	24	(71)	–	262
Goodwill	908	227	221	–	63	511	141	–	–	–	–	1,560
Identifiable assets	4,084	1,892	1,141	1,188	631	4,852	799	252	576	130	(93)	10,600
Total assets	4,992	2,119	1,362	1,188	694	5,363	940	252	576	130	(93)	12,160
Gross capital expenditures[4]	246	407	115	74	46	642	92	14	26	4	–	1,024
Year ended December 31, 2008 *($ millions)*												
Revenue	1,902	300	237	517	262	1,316	408	82	207	26	(38)	3,903
Energy supply costs	1,268	–	68	337	177	582	273	7	–	–	(18)	2,112
Operating expenses	253	130	67	50	28	275	55	14	135	16	(5)	743
Amortization	97	85	34	45	18	182	36	10	15	8	–	348
Operating income	284	85	68	85	39	277	44	51	57	2	(15)	700
Finance charges	129	42	28	33	18	121	16	8	24	80	(15)	363
Corporate taxes (recoveries)	37	(3)	6	19	7	29	2	10	10	(23)	–	65
Non-controlling interest	–	–	–	1	–	1	9	3	–	–	–	13
Net earnings (loss)	118	46	34	32	14	126	17	30	23	(55)	–	259
Preference share dividends	–	–	–	–	–	–	–	–	–	14	–	14
Net earnings (loss) applicable to common shares	118	46	34	32	14	126	17	30	23	(69)	–	245
Goodwill	903	227	221	–	63	511	161	–	–	–	–	1,575
Identifiable assets	3,721	1,574	978	1,001	520	4,073	867	285	559	126	(40)	9,591
Total assets	4,624	1,801	1,199	1,001	583	4,584	1,028	285	559	126	(40)	11,166
Gross capital expenditures[4]	220	333	117	67	46	563	110	19	14	9	–	935

(1) Includes Maritime Electric and FortisOntario. FortisOntario includes Algoma Power from October 2009.

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

(3) Results for 2009 reflected the expiry on April 30, 2009, at the end of a 100-year term, of the 75 MW of water-right entitlement associated with the Rankine hydroelectric generating facility at Niagara Falls.

(4) Related to utility capital assets, including amounts for AESO transmission capital projects, income producing properties and intangible assets

Inter-segment transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant inter-segment transactions primarily related to the sale of energy from Fortis Generation to Belize Electricity and FortisOntario, electricity sales from Newfoundland Power to Fortis Properties and finance charges on inter-segment borrowings. The significant inter-segment transactions during the years ended December 31 were as follows:

(in millions)	**2009**	2008
Sales from Fortis Generation to Regulated Electric Utilities – Caribbean	**$ 17**	$ 17
Sales from Fortis Generation to Other Canadian Electric Utilities	**1**	1
Sales from Newfoundland Power to Fortis Properties	**4**	4
Inter-segment finance charges on borrowings from:		
Corporate to Regulated Electric Utilities – Canadian	**1**	2
Corporate to Regulated Electric Utilities – Caribbean	**6**	5
Corporate to Fortis Properties	**8**	8

23. Supplementary Information to Consolidated Statements of Cash Flows

(in millions)	**2009**	2008
Interest paid	**$ 378**	$ 380
Income taxes paid	**85**	33

24. Capital Management

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

Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in the utilities' customer rates.

The consolidated capital structure of Fortis as at December 31, 2009 compared to December 31, 2008 is presented in the following table.

	2009		2008	
	(in millions)	*(%)*	*(in millions)*	*(%)*
Total debt and capital lease obligations (net of cash)[(1)]	**$ 5,830**	**60.2**	$ 5,468	59.5
Preference shares[(2)]	**667**	**6.9**	667	7.3
Common shareholders' equity	**3,193**	**32.9**	3,046	33.2
Total	**$ 9,690**	**100.0**	$ 9,181	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

Certain of the Corporation's long-term debt obligations have covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 70 per cent of the Corporation's consolidated capital structure, as defined by the long-term debt agreements. As at December 31, 2009, the Corporation and its subsidiaries, except for certain debt at Belize Electricity and the Exploits Partnership, as described below, were in compliance with their debt covenants.

As a result of the regulator's Final Decision on Belize Electricity's 2008/2009 Rate Application in June 2008, Belize Electricity does not meet certain debt covenant financial ratios related to loans with the International Bank for Reconstruction and Development and the Caribbean Development Bank totalling $7 million (BZ$12 million) as at December 31, 2009. The Company has informed the lenders of the defaults and has requested appropriate waivers.

December 31, 2009 and 2008

24. Capital Management (cont'd)

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 $59 million as at December 31, 2009 (December 31, 2008 – $61 million). The lenders of the term loan have not demanded accelerated repayment. See Note 28 for further information on the Exploits Partnership.

The Corporation's credit ratings and consolidated credit facilities are discussed further under "Liquidity Risk" in Note 26.

25. Financial Instruments

The Corporation has designated its non-derivative financial instruments as follows:

	As at December 31, 2009		As at December 31, 2008	
(in millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Held for trading				
Cash and cash equivalents[(1)]	**$ 85**	**$ 85**	$ 66	$ 66
Loans and receivables				
Trade and other accounts receivable[(1)(2)(3)]	**595**	**595**	674	674
Other receivables due from customers[(1)(3)(4)]	**7**	**7**	8	8
Other financial liabilities				
Short-term borrowings[(1)(3)]	**415**	**415**	410	410
Trade and other accounts payable[(1)(3)(5)]	**730**	**730**	782	782
Dividends payable[(1)(3)]	**3**	**3**	47	47
Customer deposits[(1)(3)(6)]	**7**	**7**	6	6
Long-term debt, including current portion[(7)(8)]	**5,502**	**5,906**	5,122	5,040
Preference shares, classified as debt[(7)(9)]	**320**	**348**	320	329

(1) Due to the nature and/or short-term maturity of these financial instruments, carrying value approximates fair value.

(2) Included in accounts receivable on the consolidated balance sheet

(3) Carrying value approximates amortized cost

(4) Included in other assets on the consolidated balance sheet

(5) Included in accounts payable and accrued charges on the consolidated balance sheet

(6) Included in deferred credits on the consolidated balance sheet

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

(8) Carrying value as at December 31, 2009 excludes unamortized deferred financing costs of $39 million (December 31, 2008 – $34 million) and capital lease obligations of $37 million (December 31, 2008 – $36 million).

(9) Preference shares classified as equity are excluded from the requirements of CICA Handbook Section 3855, *Financial Instruments – Recognition and Measurement*; however, the estimated fair value of the Corporation's $347 million preference shares classified as equity was $356 million as at December 31, 2009 (December 31, 2008 – carrying value of $347 million; fair value of $268 million).

The carrying values of financial instruments included in current assets, current liabilities, other assets and deferred credits in the consolidated balance sheets of Fortis approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or the nature of these instruments.

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

From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas prices through the use of derivative financial instruments. The Corporation does not hold or issue derivative financial instruments for trading purposes. The following table summarizes the valuation of the Corporation's derivative financial instruments as at December 31.

	2009				2008	
Asset (Liability)	**Term to Maturity** *(years)*	**Number of Contracts**	**Carrying Value** *(in millions)*	**Estimated Fair Value** *(in millions)*	Carrying Value *(in millions)*	Estimated Fair Value *(in millions)*
Interest rate swaps[(1)(2)]	**1**	**1**	**$ –**	**$ –**	$ –	$ –
Foreign exchange forward contract[(3)(4)]	**< 2**	**1**	**–**	**–**	7	7
Natural gas derivatives:[(2)(5)]						
Swaps and options	**Up to 5**	**223**	**(119)**	**(119)**	(84)	(84)
Gas purchase contract premiums	**Up to 2**	**69**	**(3)**	**(3)**	(8)	(8)

(1) The interest rate swap contract matures in October 2010. The contract has the effect of fixing the rate of interest on the non-revolving credit facilities of Fortis Properties at 5.32 per cent.

(2) The fair value measurements are Level 1, based on the three levels that distinguish the level of pricing observability utilized in measuring fair value.

(3) The fair value measurement is Level 2, based on the three levels that distinguish the level of pricing observability utilized in measuring fair value.

(4) The fair value of the foreign exchange forward contract was recorded in accounts receivable as at December 31, 2009 and 2008.

(5) The fair value of the natural gas derivatives was recorded in accounts payable as at December 31, 2009 and 2008.

The fair value of the Corporation's financial instruments, including derivatives, reflects a point-in-time estimate 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 earnings or cash flows.

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

FortisAlberta has a concentration of credit risk as a result of its distribution-service billings being to a relatively small group of retailers, and as at December 31, 2009 its gross credit risk exposure was approximately $90 million, representing the projected value of retailer billings over a 60-day period. The Company has reduced its exposure to approximately $1 million by obtaining from the retailers either a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating.

The Terasen Gas companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments. The Terasen Gas companies are also exposed to significant credit risk on physical off-system sales. To help mitigate credit risk, the Terasen Gas companies deal with high credit-quality institutions in accordance with established credit-approval practices. The counterparties with which the Terasen Gas companies have significant transactions are A-rated entities or better. The Company uses netting arrangements to reduce credit risk and net settles payments with counterparties where net settlement provisions exist.

The aging analysis of the Corporation's consolidated trade and other accounts receivable, net of an allowance for doubtful accounts of $17 million as at December 31, 2009 (December 31, 2008 – $16 million), excluding derivative financial instruments recorded in accounts receivable, was as follows:

December 31, 2009 and 2008

26. Financial Risk Management (cont'd)

(in millions)	**As at December 31, 2009**	As at December 31, 2008
Not past due	**$ 527**	$ 585
Past due 0–30 days	**52**	68
Past due 31–60 days	**8**	13
Past due 61 days and over	**8**	8
	$ 595	$ 674

As at December 31, 2009, other receivables due from customers of $7 million (included in other assets) will be received over the next five years and thereafter, with $2 million expected to be received in 2010, $3 million over 2011 and 2012, $1 million over 2013 and 2014 and $1 million due after 2014.

Liquidity Risk

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

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

The Corporation's committed credit facility is available for interim financing of acquisitions and for general corporate purposes. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends. Over the next five years, average annual consolidated long-term debt maturities and repayments are expected to be approximately $270 million. The combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

As at December 31, 2009, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.2 billion, of which approximately $1.4 billion was unused. The credit facilities are syndicated almost entirely with the seven largest Canadian banks, with no one bank holding more than 25 per cent of these facilities.

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

(in millions)	Corporate and Other	Regulated Utilities	Fortis Properties	**Total as at December 31, 2009**	Total as at December 31, 2008
Total credit facilities	$ 645	$ 1,495	$ 13	**$ 2,153**	$ 2,228
Credit facilities utilized:					
Short-term borrowings	–	(409)	(6)	**(415)**	(410)
Long-term debt *(Note 11)*[(1)]	(125)	(83)	–	**(208)**	(224)
Letters of credit outstanding	(1)	(98)	(1)	**(100)**	(104)
Credit facilities unused	$ 519	$ 905	$ 6	**$ 1,430**	$ 1,490

[(1)] As at December 31, 2009, credit facility borrowings classified as long-term debt included $13 million (December 31, 2008 – $8 million) that was included in current installments of long-term debt and capital lease obligations on the consolidated balance sheet.

As at December 31, 2009 and 2008, 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.

Corporate and Other
Terasen has a $30 million unsecured committed revolving credit facility, maturing May 2011, that is available for general corporate purposes.

Fortis has a $600 million unsecured committed revolving credit facility, maturing May 2012, and a $15 million unsecured demand credit facility. Both facilities are available for general corporate purposes and the committed facility is also available for interim financing of acquisitions.

Regulated Utilities
TGI has a $500 million unsecured committed revolving credit facility, maturing August 2013. TGVI has a $350 million unsecured committed revolving credit facility, maturing January 2011. The facilities are utilized to finance working capital requirements and capital expenditures and for general corporate purposes. TGVI also has a $20 million subordinated unsecured committed non-revolving credit facility, maturing January 2013. This facility can only be utilized for refinancing annual repayments on non-interest bearing government loans.

FortisAlberta has a $200 million unsecured committed revolving credit facility, maturing May 2012, utilized to finance capital expenditures and for general corporate purposes. With the consent of the lenders, the amount of the facility can be increased to $250 million. FortisAlberta also has a $10 million unsecured demand credit facility.

FortisBC has a $150 million unsecured committed revolving credit facility, of which $50 million matures May 2012 and the remaining $100 million matures May 2010. Additionally, the Company has the option to increase the credit facility to an aggregate of $200 million, subject to bank approval. This facility is utilized to finance capital expenditures and for general corporate purposes. FortisBC also has a $10 million unsecured demand credit facility.

Newfoundland Power has $120 million of unsecured credit facilities, comprised of a $100 million committed revolving credit facility, which matures August 2011, and a $20 million demand credit facility.

Maritime Electric has a $50 million unsecured committed revolving credit facility, which matures annually in March, and a $5 million unsecured demand credit facility.

FortisOntario has secured lines of credit totalling $20 million, of which $14 million is authorized solely for letters of credit.

Caribbean Utilities has unsecured credit facilities of US$33 million ($34 million), comprised of a capital expenditure line of credit of US$18 million ($19 million), including amounts available for letters of credit, a US$7.5 million ($8 million) operating line of credit and a US$7.5 million ($8 million) catastrophe standby loan.

Fortis Turks and Caicos has unsecured credit facilities of US$21 million ($22 million), comprised of an operating credit facility of US$5 million ($5 million), a capital expenditure line of credit of US$7 million ($7 million) and a US$9 million ($9.5 million) emergency standby loan.

Belize Electricity has an unsecured BZ$2 million ($1 million) and a secured BZ$5 million ($3 million) demand overdraft credit facility with Belize Bank Limited and Scotiabank, respectively.

Fortis Properties
Fortis Properties has a $13 million secured revolving demand credit facility utilized for general corporate purposes.

Furthermore, the Corporation and its currently rated utilities target investment-grade credit ratings to maintain capital market access at reasonable interest rates. As at December 31, 2009, the Corporation's credit ratings were as follows:

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

The credit ratings reflect the diversity of the operations of Fortis, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level and the continued focus of Fortis on pursuing the acquisition of stable regulated utilities.

December 31, 2009 and 2008

26. Financial Risk Management (cont'd)

The following is an analysis of the contractual maturities of the Corporation's financial liabilities as at December 31, 2009.

Financial Liabilities

(in 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	$ 415	$ –	$ –	$ –	**$ 415**
Trade and other accounts payable	730	–	–	–	**730**
Natural gas derivatives[(1)]	81	31	5	–	**117**
Foreign exchange forward contract[(2)]	14	1	–	–	**15**
Dividends payable	3	–	–	–	**3**
Customer deposits[(3)]	2	2	1	2	**7**
Long-term debt, including current portion[(4)]	222	312	797	4,171	**5,502**
Interest obligations on long-term debt	346	667	641	4,972	**6,626**
Preference shares, classified as debt	–	–	123	197	**320**
Dividend obligations on preference shares, classified as interest expense	17	33	24	16	**90**
	$ 1,830	$ 1,046	$ 1,591	$ 9,358	**$ 13,825**

(1) Amounts disclosed are on a gross cash flow basis. The derivatives were recorded in accounts payable at fair value as at December 31, 2009 at $122 million.

(2) Amounts disclosed are on a gross cash flow basis. The contract was recorded in accounts receivable at fair value as at December 31, 2009 at $0.2 million.

(3) Customer deposits were recorded in deferred credits as at December 31, 2009.

(4) Excludes deferred financing costs of $39 million and capital lease obligations of $37 million

Market Risk

Foreign Exchange Risk

The Corporation's earnings from, and net investment in, its self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars or in a currency pegged to the US dollar. Belize Electricity's reporting currency is the Belizean dollar while the reporting currency of Caribbean Utilities, Fortis Turks and Caicos, FortisUS Energy and BECOL is the US dollar. The Belizean dollar is pegged to the US dollar at BZ$2.00=US$1.00.

As at December 31, 2009, the Corporation's corporately held US$390 million (December 31, 2008 – US$403 million) long-term debt had been designated as a hedge of a portion of the Corporation's foreign net investments. As at December 31, 2009, the Corporation had approximately US$174 million (December 31, 2008 – US$119 million) in foreign net investments remaining to be hedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately held US dollar borrowings that are designated as hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the foreign net investments, which are also recorded in other comprehensive income.

A 5 per cent appreciation or depreciation of the US dollar relative to the Canadian dollar would have increased or decreased earnings by approximately $1 million for the year ended December 31, 2009 (2008 – $0.6 million) and would have decreased or increased other comprehensive income by $20 million for the year ended December 31, 2009 (2008 – $25 million). This sensitivity analysis is limited to the net impact on earnings of the translation of US dollar interest expense and earnings' streams from the Corporation's foreign subsidiaries and the impact on other comprehensive income of the translation of the US dollar borrowings. The sensitivity analysis excludes the risk arising from the translation of self-sustaining foreign net investments to the Canadian dollar because such investments are not financial instruments. However, a 5 per cent appreciation or depreciation of the US dollar relative to the Canadian dollar associated with the translation of the Corporation's net investment in self-sustaining foreign subsidiaries would have increased or decreased other comprehensive income by $31 million for the year ended December 31, 2009 (2008 – $32 million).

TGVI's US dollar payments under a contract for the construction of an LNG storage facility expose TGVI to fluctuations in the US dollar-to-Canadian dollar exchange rate. TGVI entered into a foreign exchange forward contract to hedge this exposure. As at December 31, 2009, a 5 per cent appreciation or depreciation of the US dollar relative to the Canadian dollar, as it affects the measurement of the fair value of the foreign exchange forward contract, in the absence of rate regulation and with all other variables remaining constant, would have increased or decreased earnings by $1 million for the year ended December 31, 2009 (2008 – $3 million). Furthermore, TGVI has regulatory approval to defer any increase or decrease in the fair value of the foreign exchange forward contract for recovery from, or refund to, customers in future rates. Therefore, any change in fair value would have impacted regulatory assets or liabilities rather than earnings.

Interest Rate Risk
The Corporation and its subsidiaries are exposed to interest rate risk associated with short-term borrowings and floating-rate debt.

The Corporation and its subsidiaries may enter into interest rate swap agreements to help reduce this risk and, during 2009, Fortis Properties was party to two interest rate swap agreements that effectively fixed the interest rates on its variable-rate borrowings. During the third quarter of 2009, one of Fortis Properties' interest rate swaps matured. A 100 basis point increase in interest rates associated with variable-rate debt, with all other variables remaining constant, would have decreased earnings by $4 million for the year ended December 31, 2009 (2008 – $5 million). A 25 basis point decrease in interest rates associated with variable-rate debt, with all other variables remaining constant, would have increased earnings by $1 million for the year ended December 31, 2009 (2008 – $1 million). Furthermore, the Terasen Gas companies and FortisBC have regulatory approval to defer any increase or decrease in interest expense resulting from fluctuations in interest rates associated with variable-rate debt for recovery from, or refund to, customers in future rates.

As at December 31, 2009, a 100 basis point increase or decrease in interest rates as it affects the measurement of the fair value of the interest rate swap agreement would have had no effect on other comprehensive income for the year ended December 31, 2009 (2008 – increased or decreased other comprehensive income by $0.1 million).

In addition, certain of the committed credit facilities have fees that are linked to the Corporation's or its subsidiaries' credit ratings. A downward change in the credit ratings of the Corporation and its currently rated subsidiaries by one level, with all other variables remaining constant, would have decreased earnings by approximately $1 million for the year ended December 31, 2009 (2008 – $1 million).

Commodity Price Risk
The Terasen Gas companies are exposed to commodity price risk associated with changes in the market price of natural gas. This risk is minimized by entering into natural gas derivatives that effectively fix the price of natural gas purchases. The price risk-management strategy of the Terasen Gas companies aims to improve the likelihood that natural gas prices remain competitive with electricity rates, temper gas price volatility on customer rates and reduce the risk of regional price discrepancies. The natural gas derivatives are recorded on the consolidated balance sheet at fair value and any change in the fair value is deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates.

Had the price of natural gas, with all other variables remaining constant, increased by $1 per gigajoule, the fair value of the natural gas derivatives would have been less out-of-the money and, in the absence of rate regulation, other comprehensive income would have increased by $81 million for the year ended December 31, 2009 (2008 – $54 million). However, the Terasen Gas companies defer any changes in the fair value of the natural gas derivatives, subject to regulatory approval, for future recovery from, or refund to, customers in future rates. Therefore, instead of increasing other comprehensive income, current regulatory assets would have decreased by $81 million (December 31, 2008 – $54 million). Had the price of natural gas, with all other variables remaining constant, decreased by $1 per gigajoule, the fair value of the natural gas derivatives would have been further out-of-the money and, in the absence of rate regulation, other comprehensive income would have decreased by $82 million for the year ended December 31, 2009 (2008 – $52 million). However, subject to regulatory approval of the deferral, instead of decreasing other comprehensive income, current regulatory assets would have increased by $82 million (December 31, 2008 – $52 million).

The Corporation's exposure to market risk related to the foreign exchange forward contract and the natural gas derivatives represents an estimate of possible changes in fair value that would occur assuming hypothetical movements in foreign exchange rates and commodity prices. The estimates may not be indicative of actual results and do not represent the maximum possible fair value gains and losses that may occur.

December 31, 2009 and 2008

27. Commitments

(in millions)	Total	Due within 1 year	Due in years 2 and 3	Due in years 4 and 5	Due after 5 years
Gas purchase contract obligations[(1)]	**$ 746**	$ 387	$ 193	$ 166	$ –
Power purchase obligations					
FortisBC[(2)]	**2,921**	42	83	78	2,718
FortisOntario[(3)]	**509**	46	95	99	269
Maritime Electric[(4)]	**66**	47	2	2	15
Belize Electricity[(5)]	**327**	26	65	69	167
Capital cost[(6)]	**383**	15	40	42	286
Joint-use asset and shared service agreements[(7)]	**62**	4	6	6	46
Office lease – FortisBC[(8)]	**19**	1	4	3	11
Operating lease obligations[(9)]	**147**	17	31	27	72
Equipment purchase – Fortis Turks and Caicos[(10)]	**12**	8	4	–	–
Other	**30**	12	12	5	1
Total	**$ 5,222**	$ 605	$ 535	$ 497	$ 3,585

(1) Gas purchase contract obligations relate to various gas purchase contracts at the Terasen Gas companies. These obligations are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect as at December 31, 2009.

(2) Power purchase obligations for FortisBC include the Brilliant Power Purchase Agreement (the "BPPA"), as well as the power purchase agreement with BC Hydro. On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the Brilliant hydroelectric generating plant located near Castlegar, British Columbia. The BPPA requires payments based on the operation and maintenance costs and a return on capital for the plant in exchange for the specified take-or-pay amounts of power. The BPPA includes a market-related price adjustment after 30 years of the 60-year term. The power purchase agreement with BC Hydro, which expires in 2013, provides for any amount of supply up to a maximum of 200 MW but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements.

(3) Power purchase obligations for FortisOntario primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of electricity and capacity. The first contract provides approximately 237 gigawatt hours ("GWh") of energy per year and up to 45 MW of capacity at any one time. The second contract, supplying the remainder of Cornwall Electric's energy requirements, provides 100 MW of capacity and energy and provides a minimum of 300 GWh of energy per contract year. Both contracts expire in December 2019.

(4) Maritime Electric has two take-or-pay contracts for the purchase of either capacity or energy. The take-or-pay contract with NB Power includes, among other things, replacement energy and capacity for Point Lepreau during its refurbishment outage and the contract expires in December 2010. The other take or-pay contract is for transmission capacity allowing Maritime Electric to reserve 30 MW of capacity on the new international power line into the United States and expires in November 2032.

(5) Power purchase obligations for Belize Electricity include a 15-year power purchase agreement, which commenced in February 2007, between Belize Electricity and Hydro Maya Limited for the supply of 3 MW of capacity. In addition, two 15-year power purchase agreements commenced in 2009 with Belize Cogeneration Energy Limited and Belize Aquaculture Limited to provide for the supply of approximately 14 MW of capacity and up to 15 MW of capacity, respectively.

In October 2009, the Comisión Federal de Electricidad of Mexico cancelled the guaranteed power supply contract for firm energy with Belize Electricity, citing force majeure reasons. The contract was to mature in December 2010.

(6) Maritime Electric has entitlement to approximately 6.7 per cent of the output from the NB Power Dalhousie Generating Station and approximately 4.7 per cent from Point Lepreau for the life of each unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital costs of these units.

(7) FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until FortisAlberta no longer has attachments to the transmission facilities. Due to the unlimited term of this contract, the calculation of future payments after 2014 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time. FortisAlberta and an Alberta transmission service provider have also entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. The service agreements have minimum expiry terms of five years from September 1, 2005 and are subject to extension based on mutually agreeable terms.

(8) Under a sale-leaseback agreement, on September 29, 1993, FortisBC began leasing its Trail, British Columbia office building for a term of 30 years. The terms of the agreement grant FortisBC repurchase options at approximately year 20 and year 28 of the lease term.

(9) Operating lease obligations include certain office, warehouse, natural gas T&D asset, vehicle and equipment leases, and the lease of electricity distribution assets of Port Colborne Hydro.

(10) Fortis Turks and Caicos has entered into an agreement with a supplier to purchase two diesel-powered generating units with a combined capacity of approximately 18 MW for delivery in mid-2010 and early 2011.

The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by customer requests and by large capital projects specifically approved by their respective regulatory authority. The consolidated capital program of the Corporation, including non-regulated segments, is forecasted to be approximately $1.1 billion for 2010, which has not been included in the commitments table above.

In prior years, TGVI received non-interest bearing repayable loans from the federal and provincial governments of $50 million and $25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. The government loans are repayable in any fiscal year prior to 2012 under certain circumstances and subject to the ability of TGVI to obtain non-government subordinated debt financing on reasonable commercial terms. As the loans are repaid and replaced with non-government loans, utility capital assets, long-term debt and equity requirements will increase in accordance with TGVI's approved capital structure, as will TGVI's rate base, which is used in determining customer rates. The repayment criteria were met in 2009 and TGVI is expected to make a $4 million repayment on the loans in 2010 (2009 – $8 million). As at December 31, 2009, the outstanding balance of the repayable government loans was $53 million, with $4 million classified as current portion of long-term debt. Timing of the repayments of the government loans beyond 2010 are dependent upon the ability of TGVI to replace the government loans with non-government subordinated debt financing on reasonable commercial terms. TGVI, however, estimates making payments under the loans of $20 million in 2012, $14 million over 2013 and 2014 and $15 million thereafter.

Caribbean Utilities has a primary fuel supply contract with a major supplier and is committed to purchase 80 per cent of the Company's fuel requirements from this supplier for the operation of Caribbean Utilities' diesel-powered generating plant. The contract is for three years terminating in April 2010, with 9 million imperial gallons required to be purchased during 2010. The contract contains an automatic renewal clause for the years 2010 through 2012. Should any party choose to terminate the contract within that two-year period, notice must be given a minimum of one year in advance of the desired termination date.

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

Consolidated defined benefit pension funding contributions, including current service, solvency and special funding amounts, are expected to be $20 million in 2010, $8 million in 2011, $4 million in 2012 and $3 million in 2013. The contributions, however, 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 as follows for the larger defined benefit pension plans:

December 31, 2009 – Terasen (covering non-unionized employees)
December 31, 2010 – Terasen (covering unionized employees) and FortisBC
December 31, 2011 – Newfoundland Power

28. Contingent Liabilities

The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with the ordinary course of 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.

The following describes the nature of the Corporation's contingent liabilities.

Terasen

On March 26, 2007, the Minister of Small Business and Revenue and Minister Responsible for Regulatory Reform (the "Minister") in British Columbia issued a decision in respect of the appeal by TGI of an assessment of additional British Columbia Social Service Tax in the amount of approximately $37 million associated with the Southern Crossing Pipeline, which was completed in 2000. The Minister reduced the assessment to $7 million, including interest, which has been paid in full to avoid accruing further interest and recorded as a long-term regulatory deferral asset (Note 4 *(x)*). TGI was successful in its appeal to the Supreme Court of British Columbia in June 2009. The Province of British Columbia has been granted leave to appeal the decision to the British Columbia Court of Appeal.

During 2007 and 2008, a non-regulated subsidiary of Terasen received Notices of Assessment from Canada Revenue Agency ("CRA") for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the consolidated financial statements. Terasen has begun the appeal process associated with the assessments.

On July 16, 2009, Terasen was named, along with other defendants, in an action related to damages to property and chattels, including contamination to sewer lines and costs associated with remediation, related to a pipeline rupture in July 2007. Terasen has filed a statement of defence but the claim is in its early stages and the amount and outcome of it is indeterminable at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

In 2008, the Vancouver Island Gas Joint Venture ("VIGJV") commenced a lawsuit against TGVI seeking damages for alleged overpayments of past tolls and declarations for reduction of its future tolls. The Statement of Claim did not quantify damages and the case did not reach the stage where either party formally quantified VIGJV's claims. In December 2009, VIGJV abandoned its claim and in January 2010, the lawsuit was dismissed by consent dismissal order. The matter is now fully concluded.

FortisBC

The British Columbia Ministry of Forests has alleged breaches of the Forest Practices Code and negligence relating to a fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC. In addition, the Company has been served with a filed writ and statement of claim by private landowners in relation to the same matter. The Company is communicating with its insurers and has filed a statement of defence in relation to both of the actions. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Maritime Electric

In April 2006, CRA reassessed Maritime Electric's 1997–2004 taxation years. The reassessment encompasses the Company's tax treatment, specifically the Company's timing of deductions with respect to: (i) the ECAM in the 2001–2004 taxation years; (ii) customer rebate adjustments in the 2001–2003 taxation years; and (iii) the Company's payment of approximately $6 million on January 2, 2001 associated with a settlement with NB Power regarding its $450 million write-down of Point Lepreau in 1998. Maritime Electric believes it has reported its tax position appropriately in all respects and has filed a Notice of Objection with the Chief of Appeals at CRA. In December 2008, the Appeals Division of CRA issued a Notice of Confirmation, which confirmed the April 2006 reassessments. In March 2009, the Company filed an Appeal to the Tax Court of Canada.

Should Maritime Electric be unsuccessful in defending all aspects of the reassessment, the Company would be required to pay approximately $14 million in taxes and accrued interest. As at December 31, 2009, Maritime Electric has provided for this amount through future and current income taxes payable. The provisions of the *Income Tax Act* (Canada) require the Company to deposit one-half of the assessment under objection with CRA. The amount currently on deposit with CRA arising from the reassessment is approximately $6 million.

Exploits Partnership

The Exploits Partnership is owned 51 per cent by Fortis Properties and 49 per cent by Abitibi. The Exploits Partnership operated two non-regulated hydroelectric generation plants in central Newfoundland with a combined capacity of approximately 36 MW. In December 2008, the Government of Newfoundland and Labrador expropriated Abitibi's hydroelectric assets and water rights in Newfoundland, including those of the Exploits Partnership. The newsprint mill in Grand Falls-Windsor closed on February 12, 2009, subsequent to which the day-to-day operations of the Exploits Partnership's hydroelectric generating facilities were assumed by Nalcor Energy, a Crown corporation, as an agent for the Government of Newfoundland and Labrador with respect to expropriation matters. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi in the province. The loss of control over cash flows and operations has required Fortis to cease consolidation of the Exploits Partnership, effective February 12, 2009. Discussions between Fortis Properties and Nalcor Energy with respect to expropriation matters are ongoing.

29. Subsequent Event

In January 2010, Fortis completed a $250 million five-year fixed rate reset preference share offering. The net proceeds of $242 million were used to repay borrowings under the Corporation's committed credit facility and to fund an equity injection into TGI to repay borrowings under the utility's credit facilities in support of working capital and capital expenditure requirements.

30. Comparative Figures

Certain comparative figures have been reclassified to comply with current period classifications, the most significant of which was the reclassification of $48 million from other assets to utility capital assets on the consolidated balance sheet as at December 31, 2008 related to the net book value of amounts paid to AESO for transmission capital projects at FortisAlberta. Capital expenditures related to AESO transmission projects were also reclassified from change in other assets and deferred credits to utility capital asset capital expenditures on the consolidated statement of cash flows for the year ended December 31, 2008. Additionally, $12 million was reclassified from long-term regulatory liabilities to utility capital assets on the consolidated balance sheet as at December 31, 2008 related to the change in presentation adopted by FortisBC as at December 31, 2009 as described in Note 2, Utility Capital Assets.

Historical Financial Summary

Statements of Earnings *(in $ millions)*	**2009**	2008[1]	2007	2006[2]
Revenue, including equity income	**3,637**	3,903	2,718	1,472
Energy supply costs and operating expenses	**2,572**	2,855	1,904	939
Amortization	**364**	348	273	178
Finance charges	**360**	363	299	168
Corporate taxes	**49**	65	36	32
Results of discontinued operations, gains on sales and other unusual items	**–**	–	8	2
Non-controlling interest	**12**	13	15	8
Preference share dividends	**18**	14	6	2
Net earnings applicable to common share	**262**	245	193	147
Balance Sheets *(in $ millions)*				
Current assets	**1,126**	1,150	1,038	405
Goodwill	**1,560**	1,575	1,544	661
Other long-term assets	**949**	487	424	331
Utility capital assets, income producing properties and intangibles	**8,525**	7,954	7,276	4,049
Total assets	**12,160**	11,166	10,282	5,446
Current liabilities	**1,594**	1,697	1,804	558
Deposits due beyond one year	**–**	–	–	–
Deferred credits, regulatory liabilities and future income taxes	**1,307**	727	697	482
Long-term debt and capital lease obligations (excluding current portion)	**5,276**	4,884	4,623	2,558
Non-controlling interest	**123**	145	115	130
Preference share (classified as debt)	**320**	320	320	320
Shareholders' equity	**3,540**	3,393	2,723	1,398
Cash Flows *(in $ millions)*				
Operating activities	**637**	661	373	263
Investing activities	**1,052**	852	2,033	634
Financing activities	**599**	387	1,826	456
Dividends, excluding dividends on preference shares classified as debt	**161**	191	146	77
Financial Statistics				
Return on average book common shareholders' equity *(%)*	**8.41**	8.70	10.00	11.87
Capitalization Ratios *(%)* (year end)				
Total debt and capital lease obligations (net of cash)	**60.2**	59.5	64.3	61.1
Preference shares (classified as debt and equity)	**6.9**	7.3	5.2	10.0
Common shareholders' equity	**32.9**	33.2	30.5	28.9
Interest Coverage *(x)*				
Debt	**1.9**	1.9	1.9	2.2
All fixed charges	**1.8**	1.8	1.7	2.0
Total gross capital expenditures *(in $ millions)*	**1,024**	935	803	500
Common share data				
Book value per share (year end) *($)*	**18.61**	17.97	16.69	12.19
Average common shares outstanding *(in millions)*	**170.2**	157.4	137.6	103.6
Basic earnings per common share *($)*	**1.54**	1.56	1.40	1.42
Dividends declared per common share *($)*	**0.780**	1.010	0.880	0.700
Dividends paid per common share *($)*	**1.040**	1.000	0.820	0.670
Dividend payout ratio *(%)*	**67.5**	64.1	58.6	47.2
Price earnings ratio *(x)*	**18.6**	15.8	20.7	21.0
Share trading summary				
High price *($)* (TSX)	**29.24**	29.94	30.00	30.00
Low price *($)* (TSX)	**21.52**	20.70	24.50	20.36
Closing price *($)* (TSX)	**28.68**	24.59	28.99	29.77
Volume *(in thousands)*	**121,162**	132,108	100,920	60,094

(1) Certain 2008 comparative figures have been reclassified to comply with current period classifications. Refer to Notes 2 and 30 of the 2009 Annual Consolidated Financial Statements for further details.

(2) As at December 31, 2006, the regulatory provision for future asset removal and site restoration costs was reallocated from accumulated amortization to long-term regulatory liabilities, with 2005 comparative figures restated, excluding an amount previously estimated for FortisBC due to a change in presentation adoped by FortisBC effective December 31, 2009.

Historical Financial Summary

2005 (2)	2004	2003	2002	2001	2000	1999
1,441	1,146	843	715	628	580	505
926	766	579	477	418	418	356
158	114	62	65	62	52	45
154	122	86	74	65	56	46
70	47	38	32	29	17	28
10	–	–	–	4	3	–
6	6	4	4	4	3	1
–	–	–	–	–	–	–
137	91	74	63	54	37	29
299	293	191	180	135	166	93
512	514	65	60	33	36	39
471	418	345	241	172	163	122
3,315	2,713	1,563	1,459	1,246	1,056	930
4,597	3,938	2,164	1,940	1,586	1,421	1,184
412	538	296	334	272	225	230
–	–	–	–	–	–	16
477	138	62	39	32	24	27
2,136	1,905	1,031	941	746	678	488
39	37	37	40	36	32	29
320	320	123	–	50	50	50
1,213	1,000	615	586	450	412	344
304	272	157	134	94	97	85
467	1,026	308	349	240	241	122
224	777	232	261	171	178	67
64	51	38	35	30	28	24
12.40	11.28	12.30	12.23	12.44	9.73	8.55
58.7	61.4	60.0	65.2	63.9	60.4	59.6
8.6	9.4	6.7	–	3.6	4.3	5.1
32.7	29.2	33.3	34.8	32.5	35.3	35.3
2.5	2.3	2.2	2.3	2.3	2.1	2.3
2.1	2.0	2.1	2.2	2.2	1.9	2.1
446	279	208	229	149	158	86
11.74	10.45	8.82	8.50	7.50	6.97	6.55
101.8	84.7	69.3	65.1	59.5	54.1	52.2
1.35	1.07	1.06	0.97	0.90	0.68	0.56
0.605	0.548	0.525	0.498	0.470	0.460	0.455
0.588	0.540	0.520	0.485	0.468	0.460	0.453
43.7	50.3	48.9	49.9	51.9	67.6	80.8
18.0	16.2	13.9	13.5	13.0	13.2	14.0
25.64	17.75	15.24	13.28	11.89	9.19	9.93
17.00	14.23	11.63	10.76	8.56	6.88	7.29
24.27	17.38	14.73	13.13	11.74	9.00	7.85
37,706	29,254	31,180	21,676	21,460	26,760	9,024

Board of Directors

Board of Directors (back row l-r): Peter E. Case, Frank J. Crothers, Roy P. Rideout, Ida J. Goodreau; (middle row l-r): Harry McWatters, Michael A. Pavey, David G. Norris, John S. McCallum; (front row l-r): H. Stanley Marshall, Geoffrey F. Hyland, Douglas J. Haughey, Ronald D. Munkley

Geoffrey F. Hyland ∗★✷ *Chair, Fortis Inc., Caledon, ON*
Mr. Hyland, 65, joined the Fortis Inc. Board in May 2001 and was appointed Chair of the Board in May 2008. He retired as President and CEO of Shawcor Ltd. in June 2005 after 37 years of service. Mr. Hyland is a Director of FortisOntario Inc. He continues to serve on the Board of ShawCor Ltd. and is a Director of SCITI Total Return Trust and Exco Technologies Limited.

Peter E. Case ∗ *Corporate Director, Freelton, ON*
Mr. Case, 55, joined the Fortis Inc. Board in May 2005. After 17 years as a utility and pipeline analyst, he retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. He was then a consultant to the utility industry and its regulators for three years. Prior to his position at CIBC, he was Managing Director at BMO Nesbitt Burns. Mr. Case was appointed Chair of the Board of FortisOntario Inc. in 2009. He has been a Director of FortisOntario Inc. since 2003.

Frank J. Crothers *Chairman & CEO, Island Corporate Holdings, Nassau, BS*
Mr. Crothers, 65, joined the Fortis Inc. Board in May 2007. Over the past 35 years, Mr. Crothers has served on many public and private sector boards. He served a three-year term as Chairman of CARILEC, the Caribbean Association of Electrical Utilities. Mr. Crothers is the past President of P.P.C. Limited, which was acquired by Fortis Inc. in August 2006. He serves as Vice Chair of the Board of Caribbean Utilities Company, Limited and serves on the Board of Belize Electricity Limited. Mr. Crothers also serves as a Director of Templeton Mutual Funds, Talon Metals Corp. and Fidelity Merchant Bank & Trust (Cayman) Limited.

Ida J. Goodreau ✷ *Corporate Director, Vancouver, BC*
Ms. Goodreau, 58, joined the Fortis Inc. Board in May 2009. She is the past President and CEO of Lifelabs. Prior to joining Lifelabs in March 2009, Ms. Goodreau was President and CEO of the Vancouver Coastal Health Authority since 2002. She held senior leadership roles in several Canadian and international pulp and paper and natural gas companies prior to entering the health care field. She is a Director of Terasen Inc.

Douglas J. Haughey ∗ *President and CEO, Windshift Capital Corp., Calgary, AB*
Mr. Haughey, 53, joined the Fortis Inc. Board in May 2009. Prior to forming Windshift Capital Corp. in 2008, he was President and CEO of Spectra Energy Income Fund and President of Spectra Energy Transmission West, Spectra's Canadian natural gas and liquids midstream business. Mr. Haughey also led Spectra's strategic development and mergers and acquisitions teams, based in Houston, Texas. He serves as a Director of Pembina Pipeline Income Fund.

H. Stanley Marshall *President and CEO, Fortis Inc., St. John's, NL*
Mr. Marshall, 59, has served on the Fortis Inc. Board since 1995. He joined Newfoundland Power Inc. in 1979 and was appointed President and CEO of Fortis Inc. in 1996. Mr. Marshall serves on the Boards of all Fortis utilities in western Canada and the Caribbean and the Board of Fortis Properties Corporation. He is also a Director of Toromont Industries Ltd.

John S. McCallum ∗★ *Professor of Finance, University of Manitoba, Winnipeg, MB*
Mr. McCallum, 66, joined the Fortis Inc. Board in July 2001 and is Chair of the Governance and Nominating Committee of the Board. He was Chairman of Manitoba Hydro from 1991 to 2000 and Policy Advisor to the Federal Minister of Finance from 1984 to 1991. Mr. McCallum is a Director of FortisBC Inc. and FortisAlberta Inc. He also serves as a Director of IGM Financial Inc., Toromont Industries Ltd. and Wawanesa.

Harry McWatters ★ *Wine Consultant, Summerland, BC*
Mr. McWatters, 64, joined the Fortis Inc. Board in May 2007. He is the founder and past President of Sumac Ridge Estate Wine Group. Mr. McWatters is President of Harry McWatters Inc., Vintage Consulting Group Inc., Okanagan Wine Academy and Black Sage Vineyards Ltd. He was appointed Chair of the Board of FortisBC Inc. in 2006. Mr. McWatters has been a Director of FortisBC Inc. since 2005 and a Director of Terasen Inc. since November 2007.

Ronald D. Munkley ★ *Corporate Director, Mississauga, ON*
Mr. Munkley, 63, joined the Fortis Inc. Board in May 2009. He retired in April 2009 as Vice Chairman and Head of the Power and Utility Business of CIBC World Markets. Mr. Munkley had acted as an advisor on most Canadian utility transactions since joining CIBC World Markets in 1998. Prior to that, he was employed at Enbridge Consumers Gas for 27 years, culminating as Chairman, President and CEO. He led Enbridge Consumers Gas through deregulation and restructuring in the 1990s.

David G. Norris ∗✷ *Corporate Director, St. John's, NL*
Mr. Norris, 62, joined the Fortis Inc. Board in May 2005 and was appointed Chair of the Audit Committee of the Board in May 2006. He has been a financial and management consultant since 2001, prior to which he was Executive Vice-President, Finance and Business Development, Fishery Products International Limited. Previously, he held Deputy Minister positions with the Department of Finance and Treasury Board, Government of Newfoundland and Labrador. Mr. Norris was appointed Chair of the Board of Newfoundland Power Inc. in 2006. He has been a Director of Newfoundland Power Inc. since 2003 and a Director of Fortis Properties Corporation since 2006.

Michael A. Pavey ✷ *Corporate Director, Moncton, NB*
Mr. Pavey, 62, joined the Fortis Inc. Board in May 2004. He retired as Executive Vice-President and Chief Financial Officer of Major Drilling Group International Inc. in 2006. Prior to joining Major Drilling in 1999, he held senior executive positions with a major integrated electric utility in western Canada. Mr. Pavey was previously a Director of Maritime Electric Company, Limited.

Roy P. Rideout ★✷ *Corporate Director, Halifax, NS*
Mr. Rideout, 62, joined the Fortis Inc. Board in March 2001 and is Chair of the Human Resources Committee of the Board. He retired as Chairman and CEO of Clarke Inc. in October 2002. Prior to 1998, Mr. Rideout served as President of Newfoundland Capital Corporation Limited and held senior executive positions in the Canadian airline industry. He also serves as a Director of NAV CANADA.

∗ Audit Committee
★ Governance and Nominating Committee
✷ Human Resources Committee

Investor Information

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare") is responsible for the maintenance of shareholder records and the issuance, transfer and cancellation of stock certificates. Transfers can be effected at its Halifax, Montreal and Toronto offices. Computershare also distributes dividends and shareholder communications. Inquiries with respect to these matters and corrections to shareholder information should be addressed to the Transfer Agent.

Computershare Trust Company of Canada

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F: 416.263.9394 or 1.888.453.0330
W: www.computershare.com/fortisinc

Direct Deposit of Dividends

Shareholders may obtain automatic electronic deposit of dividends to their designated Canadian financial institutions by contacting the Transfer Agent.

Duplicate Annual Reports

While every effort is made to avoid duplications, some shareholders may receive extra reports as a result of multiple share registrations. Shareholders wishing to consolidate these accounts should contact the Transfer Agent.

Eligible Dividend Designation

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on common and preferred shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends". Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

Expected Dividend* and Earnings Dates

Dividend Record Dates

May 7, 2010	August 6, 2010
November 5, 2010	February 4, 2011

Dividend Payment Dates

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

Earnings Release Dates

April 30, 2010	August 4, 2010
November 5, 2010	February 3, 2011

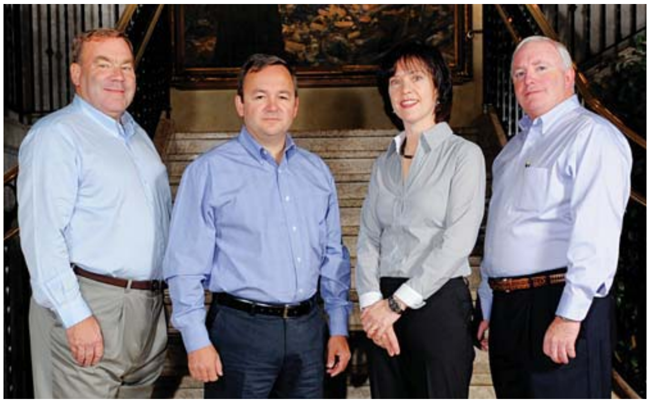
* *The declaration and payment of dividends are subject to the Board of Directors' approval.*

Dividend Reinvestment Plan and Consumer Share Purchase Plan

Fortis offers a Dividend Reinvestment Plan ("DRIP")[(1)] and a Consumer Share Purchase Plan ("CSPP")[(2)] to common shareholders as a convenient method of increasing their investments in Fortis. Participants have dividends plus any optional contributions (DRIP: minimum of $100, maximum of $30,000 annually; CSPP: minimum of $25, maximum of $20,000 annually) automatically deposited in the Plans to purchase additional Common Shares. Shares can be purchased quarterly on March 1, June 1, September 1 and December 1 at the average market price then prevailing on the Toronto Stock Exchange. The DRIP offers a 2 per cent discount on the purchase of Common Shares, issued from treasury, with the reinvested dividends. Inquiries should be directed to the Transfer Agent.

(1) All registered holders of Common Shares who are residents of Canada are eligible to participate in the DRIP. Shareholders residing outside Canada may also participate unless participation is not allowed in that jurisdiction. Residents of the United States, its territories or possessions are not eligible to participate.

(2) The CSPP is offered to residents of the provinces of Newfoundland and Labrador and Prince Edward Island.



Fortis Inc. Officers (l-r): Stan Marshall, President and CEO; Barry Perry, VP, Finance and CFO; Donna Hynes, Assistant Secretary and Manager, Investor and Public Relations; Ronald McCabe, VP, General Counsel and Corporate Secretary

Share Listings

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

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	$ 1.531
February 22, 1994	$ 7.156

Analyst and Investor Inquiries

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Annual Meeting

Tuesday, May 4, 2010
10:30 a.m.
Holiday Inn St. John's
180 Portugal Cove Road
St. John's, NL Canada

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