FORTIS INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2009

March 8, 2010

ANNUAL INFORMATION FORM
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DEFINITIONS OF CERTAIN TERMS

Certain terms used in the Annual Information Form for the year ended December 31, 2009 are defined below:

"2009 Annual Information Form" means the Fortis Inc. Annual Information Form for the year ended December 31, 2009;

"Abitibi" means AbitibiBowater Inc.;

"Advisory Panel" means the Advisory Panel on Canada's System of International Taxation;

"Algoma Power" means Algoma Power Inc.;

"AUC" means Alberta Utilities Commission;

"BAL" means Belize Aquaculture Limited;

"BC Hydro" means BC Hydro and Power Authority;

"BCUC" means British Columbia Utilities Commission;

"BELCOGEN" means Belize Cogeneration Energy Limited;

"BECOL" means Belize Electric Company Limited;

"Belize Electricity" means Belize Electricity Limited;

"BEPC" means Brilliant Expansion Power Corporation;

"BEWU" means Belize Energy Workers Union;

"Board" means Board of Directors of Fortis Inc.;

"BPC" means Brilliant Power Corporation;

"BZ" means Belizean currency, which is pegged to the United States currency (BZ$2.00=US$1.00);

"Canadian GAAP" means Canadian generally accepted accounting principles;

"Canadian Niagara Power" means Canadian Niagara Power Inc.;

"Caribbean Utilities" means Caribbean Utilities Company, Ltd.;

"CAW" means Canadian Auto Workers-Retail/Wholesale;

"CEP" means Communications, Energy and Paperworkers Union of Canada;

"CFE" means Comisión Federal de Electricidad;

"CICA" means Canadian Institute of Chartered Accountants;

"CIP" means Capital Investment Plan;

"COPE" means Canadian Office & Professional Employees Union;

"Cornwall Electric" means Cornwall Street Railway, Light and Power Company, Limited;

"Corporation" means Fortis Inc.;

"COS" means cost of service;

"CPA" means Canal Plant Agreement;

"CPC/CBT" means Columbia Power Corporation and the Columbia Basin Trust;

"CPI" means consumer price index;

"CRA" means Canada Revenue Agency;

"CUPE" means Canadian Union of Public Employees;

"DBRS" means DBRS Limited;

"ECAM" means energy cost adjustment mechanism;

"ERA" means Electricity Regulatory Authority;

"Exploits Partnership" means Exploits River Hydro Partnership between Abitibi and Fortis Properties Corporation;

"External Auditor" means the firm of chartered accountants registered with the Canadian Public Accountability Board or its successor and appointed by the shareholders of the Corporation to act as external auditor of the Corporation;

"FERC" means United States Federal Energy Regulatory Commission;

"First Preference Share, Series H" means Cumulative Redeemable Five-Year Fixed Rate Reset First Preference Shares, Series H;

"Fortis" means Fortis Inc.;

"FortisAlberta" means FortisAlberta Inc.;

"FortisAlberta Holdings" means FortisAlberta Holdings Inc.;

"FortisBC" means, collectively, the operations of FortisBC Inc. and its parent company, Fortis Pacific Holdings Inc., but excluding its wholly owned partnership, Walden Power Partnership;

"FortisOntario" means, collectively, the operations of Canadian Niagara Power, Cornwall Electric and Algoma Power. Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc.;

"FortisOntario Inc." means the successor to Canadian Niagara Power Company, Limited and the parent company of Canadian Niagara Power, Cornwall Electric and Algoma Power;

"Fortis Pacific Holdings" means Fortis Pacific Holdings Inc.;

"Fortis Properties" means Fortis Properties Corporation;

"Fortis Turks and Caicos" means, collectively, P.P.C. Limited and Atlantic Equipment & Power (Turks and Caicos) Ltd.;

"FortisUS Energy" means FortisUS Energy Corporation;

"FortisWest" means FortisWest Inc.;

"GWh" means gigawatt hour(s);

"Hydro One" means Hydro One Networks Inc.;

"IASB" means International Accounting Standards Board;

"IBEW" means International Brotherhood of Electrical Workers;

"IESO" means Independent Electricity System Operator of Ontario;

"IFRS" means International Financial Reporting Standards;

"IRAC" means Island Regulatory and Appeals Commission;

"IRM" means Incentive Regulation Mechanism;

"ISO" means International Organization for Standardization;

"kWh" means kilowatt hour(s);

"MD&A" means the Corporation's Management Discussion and Analysis, located on pages 20 through 81 of the Corporation's 2009 Annual Report to Shareholders, prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations,* in respect of the Corporation's annual and interim financial statements;

"Management" means, collectively, senior officers of the Corporation;

"Maritime Electric" means Maritime Electric Company, Limited;

"Moody's" means Moody's Investors Service;

"MW" means megawatt(s);

"NB Power" means New Brunswick Power Corporation;

"NEB" means National Energy Board;

"Newfoundland Hydro" means Newfoundland and Labrador Hydro;

"Newfoundland Power" means Newfoundland Power Inc.;

"NSA" means Negotiated Settlement Agreement;

"OEB" means Ontario Energy Board;

“Other Canadian Electric Utilities” means, collectively, the operations of FortisOntario and Maritime Electric;

“PBR” means performance-based rate-setting methodology for regulation of public utilities;

“PCB” means polychlorinated biphenyl;

“PIF” means productivity improvement factor;

“PJ” means petajoule(s);

“Point Lepreau” means NB Power Point Lepreau Nuclear Generating Station;

“Port Colborne Hydro” means Port Colborne Hydro Inc.;

“PUB” means Newfoundland and Labrador Board of Commissioners of Public Utilities;

“PUC” means Public Utilities Commission (Belize);

“PWU” means Power Workers Union, a CUPE affiliate as CUPE Local 1000;

“ROA” means regulated rate of return on rate base assets;

“ROE” means rate of return on common shareholders’ equity;

“S&P” means Standard & Poor’s;

“Teck Cominco” means Teck Cominco Metals Ltd.;

“Terasen Gas companies” means, collectively, the operations of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.;

“Terasen” means Terasen Inc., the holding company of the Terasen Gas companies;

“TGI” means Terasen Gas Inc.;

“TGVI” means Terasen Gas (Vancouver Island) Inc.;

“TGWI” means Terasen Gas (Whistler) Inc.;

“TIEA” means tax information-exchange agreements;

“TJ” means terajoule(s);

“TQM” means Trans Quebec & Maritimes Inc.;

“TransAlta” means TransAlta Utilities Corporation;

“UFCW” means United Food and Commercial Workers;

“USW” means United Steel Workers;

“UUWA” means United Utility Worker’s Association;

"VAD" means value added delivery;

"VIGJV" means Vancouver Island Gas Joint Venture;

"VINGPA" means Vancouver Island Natural Gas Pipeline Agreement;

"Walden" means Walden Power Partnership; and

"Whistler" means the Resort Municipality of Whistler.

1.0 CORPORATE STRUCTURE

The 2009 Annual Information Form has been prepared in accordance with National Instrument 52-102 – *Continuous Disclosure Obligations*. Financial information has been prepared in accordance with Canadian GAAP and is presented in Canadian dollars unless otherwise specified.

Except as otherwise stated, the information in the 2009 Annual Information Form is given as of December 31, 2009.

Fortis includes forward-looking information in the 2009 Annual Information Form 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 2009 Annual Information Form, including the 2009 MD&A incorporated herein by reference, 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 IFRS; changes in tax legislation; information technology infrastructure; an ultimate resolution of the expropriation of the assets of the Exploits Partnership that differs from what is currently expected by management; an unexpected outcome of legal proceedings currently against the Corporation; relations with First Nations; labour relations and human resources. For additional information with respect to the Corporation's risk factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and to the heading "Risk Factors" in this 2009 Annual Information Form.

All forward-looking information in this 2009 Annual Information Form 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.

1.1 Name and Incorporation

Fortis is a holding company that was incorporated as 81800 Canada Ltd. under the *Canada Business Corporations Act* on June 28, 1977 and continued under the *Corporations Act* (Newfoundland and Labrador) on August 28, 1987.

The articles of incorporation of the Corporation were amended to: (a) change its name to Fortis on October 13, 1987; (b) set out the rights, privileges, restrictions and conditions attached to the Common Shares on October 15, 1987; (c) designate 2,000,000 First Preference Shares, Series A on September 11, 1990; (d) replace the class rights, privileges, restrictions and conditions attaching to the First Preference Shares and the Second Preference Shares on July 22, 1991; (e) designate 2,000,000 First Preference Shares, Series B on December 13, 1995; (f) designate 5,000,000 First Preference Shares, Series C on May 27, 2003; (g) designate 8,000,000 First Preference Shares, Series D and First Preference Shares, Series E on January 23, 2004; (h) amend the redemption provisions attaching to the First Preference Shares, Series D on July 15, 2005; (i) designate 5,000,000 First Preference Shares, Series F on September 22, 2006; (j) designate 9,200,000 First Preference Shares, Series G on May 20, 2008; and (k) designate 10,000,000 First Preference Shares, Series H on January 20, 2010.

Fortis redeemed all of its outstanding First Preference Shares, Series A and First Preference Shares, Series B on September 30, 1997 and December 2, 2002, respectively. On June 3, 2003, Fortis issued 5,000,000 First Preference Shares, Series C. On January 29, 2004, Fortis issued 8,000,000 First Preference Units, each unit consisting of one First Preference Share, Series D and one Warrant. During 2004, 7,993,500 First Preference Units were converted into 7,993,500 First Preference Shares, Series E and 6,500 First Preference Shares, Series D remained outstanding. On September 20, 2005, the 6,500 First Preference Shares, Series D were redeemed by the Corporation. On September 28, 2006, Fortis issued 5,000,000 First Preference Shares, Series F. On May 23, 2008, Fortis issued 8,000,000 First Preference Shares, Series G and on June 4, 2008 issued an additional 1,200,000 First Preference Shares, Series G, following the exercise of an over-allotment option in connection with the offering of the 8,000,000 First Preference Shares, Series G. On January 26, 2010, Fortis issued 10,000,000 First Preference Shares, Series H.

The corporate head and registered office of Fortis is located at the Fortis Building, Suite 1201, 139 Water Street, P.O. Box 8837, St. John's, NL, Canada, A1B 3T2.

1.2 Inter-Corporate Relationships

Fortis is principally an international distribution utility holding company. Its regulated holdings include electric distribution utilities in five Canadian provinces and three Caribbean countries and a natural gas utility in British Columbia. As at December 31, 2009, regulated utility assets comprised approximately 93 per cent of the Corporation's total assets, with the balance primarily comprised of non-regulated generation assets, mainly hydroelectric, across Canada and in Belize and Upper New York State, and hotels and commercial office and retail space in Canada.

The following table lists the principal subsidiaries of the Corporation, their jurisdictions of incorporation and the percentage of votes attaching to voting securities held directly or indirectly by the Corporation as at March 8, 2010. This table excludes certain subsidiaries, the total assets of which individually constituted less than 10 per cent of the Corporation's consolidated assets as at December 31, 2009, or the total revenue of which individually constituted less than 10 per cent of the Corporation's 2009 consolidated revenue. Additionally, the principal subsidiaries together comprise 79 per cent of the Corporation's consolidated assets as at December 31, 2009 and 76 per cent of the Corporation's 2009 consolidated revenue.

Principal Subsidiaries

Subsidiary	Jurisdiction of Incorporation	Percentage of votes attaching to voting securities beneficially owned, controlled or directed by the Corporation
Terasen	British Columbia	100
FortisAlberta [(1)]	Alberta	100
FortisBC Inc. [(2)]	British Columbia	100
Newfoundland Power	Newfoundland and Labrador	93.9[(3)]

(1) *FortisAlberta Holdings, an Alberta corporation, owns all of the shares of FortisAlberta. FortisWest, a Canadian corporation, owns all of the shares of FortisAlberta Holdings. Fortis owns all of the shares of FortisWest.*

(2) *Fortis Pacific Holdings, a British Columbia corporation, owns all of the shares of FortisBC Inc. FortisWest, a Canadian corporation, owns all of the shares of Fortis Pacific Holdings. Fortis owns all of the shares of FortisWest.*

(3) *Fortis owns all of the common shares; 182,300 First Preference Shares, Series G; 33,181 First Preference Shares, Series B; 13,000 First Preference Shares, Series D and 1,713 First Preference Shares, Series A of Newfoundland Power which, at March 8, 2010, represented 93.9 per cent of its voting securities. The remaining 6.1 per cent of Newfoundland Power's voting securities consist of First Preference Shares, Series A, B, D and G which are primarily held by the public.*

2.0 GENERAL DEVELOPMENT OF THE BUSINESS

2.1 Three-Year History

Over the past three years, the business operations of Fortis have increased significantly. Total assets have grown more than 2.2 times from $5.4 billion as at December 31, 2006 to $12.2 billion as at December 31, 2009. The Corporation's shareholders' equity has also grown 2.5 times from $1.4 billion as at December 31, 2006 to $3.5 billion as at December 31, 2009. Net earnings applicable to common shares have increased from $147 million in 2006 to $262 million in 2009.

The significant growth reflects the Corporation's profitable growth strategy for its principal businesses of regulated gas and electricity distribution. This strategy includes a combination of growth through acquisitions and organic growth through the Corporation's consolidated capital expenditure program.

The significant growth over the past three years primarily reflected the approximate $3.7 billion acquisition of Terasen in May 2007. The addition of Terasen's gas distribution business doubled the Corporation's investment in regulated rate base assets and marked the Corporation's expansion into natural gas distribution. In addition, Fortis increased its regulated utility investments in Canada through the acquisition of Algoma Power, in October 2009, for $75 million and increased its investment in Caribbean Utilities, over the three-year period, from approximately 54 per cent in 2006 to approximately 59 per cent held as at December 31, 2009. Algoma Power is a regulated electric distribution utility servicing approximately 12,000 customers in the District of Algoma in northern Ontario. The Corporation also increased its non-regulated investments, over the last three years, through the acquisition of three hotels in Canada.

Organic growth has been driven by the capital expenditure programs at FortisAlberta, FortisBC and the Terasen Gas companies. Total assets at FortisAlberta and FortisBC have grown by approximately 53 per cent and 33 per cent, respectively, over the past three years. Total assets at Terasen have grown approximately 22 per cent since May 17, 2007, the date of acquisition.

2.2 Outlook

The Corporation maintains a profitable growth strategy for its principal businesses of regulated gas and electricity distribution. This strategy includes a combination of growth through acquisitions and organic growth through the Corporation's consolidated capital expenditure program.

The Corporation's principal businesses of regulated gas and electricity distribution are capital intensive. Over the next five years, the Corporation's consolidated gross capital expenditures are expected to approach $5 billion. Approximately 70 per cent of the capital spending is expected 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.

Gross consolidated capital expenditures for 2010 are expected to be approximately $1.1 billion, as summarized in the following table. 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.

Forecast Gross Capital Expenditures (1) **Year Ending December 31, 2010**	
	($ millions)
Terasen Gas Companies	327
FortisAlberta (2)	363
FortisBC	168
Newfoundland Power	69
Other Canadian Electric Utilities	47
Regulated Electric Utilities – Caribbean	82
Non-Regulated Utility (3)	16
Fortis Properties	26
Total	**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 the Allowance for Funds Used During Construction.*

(2) *Includes forecast payments to be made to the Alberta Electric System Operator for investment in transmission capital projects*

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

The Corporation's subsidiaries expect to have reasonable access to long-term capital in 2010 to fund their 2010 capital expenditure programs.

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.

3.0 DESCRIPTION OF THE BUSINESS

Fortis is principally an international distribution utility holding company. Its core business is highly regulated and is segmented by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation, and commercial office and retail space and hotels, which are treated as two separate segments. The Corporation's reporting segments allow 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 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 following sections describe the operations in each of the Corporation's reportable segments.

3.1 Regulated Gas Utilities - Canadian

3.1.1 *Terasen Gas Companies*

The Regulated Gas Utilities - Canadian segment comprises the natural gas transmission and distribution business of TGI, TGVI and TGWI, collectively referred to as the Terasen Gas companies.

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 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 Whistler, British Columbia, which provides service to approximately 2,600 residential and commercial customers.

The Terasen Gas companies own and operate more than 46,000 kilometres of natural gas distribution and transmission pipelines and met a peak day demand of 1,234 TJ in 2009.

Market and Sales

The Terasen Gas companies' annual customer gas volumes decreased to 207,230 TJ in 2009 from 221,122 TJ in 2008. Revenue was approximately $1.7 billion in 2009 compared to $1.9 billion in 2008.

The following table compares the composition of 2009 and 2008 revenue and gas volumes by customer class of the Terasen Gas companies.

Terasen Gas Companies
Revenue and Gas Volumes by Customer Class

	Revenue (per cent)		PJ Volumes (per cent)	
	2009	2008	**2009**	2008
Residential	**56.9**	57.7	**37.6**	35.5
Commercial	**33.9**	33.1	**22.9**	19.9
Small industrial	**1.7**	1.7	**2.8**	1.4
Large industrial and other	**0.1**	0.1	**0.1**	0.1
	92.6	92.6	**63.4**	56.9
Transportation and other	**7.4**	7.4	**36.6**	43.1
Total	**100.0**	100.0	**100.0**	100.0

Gas Purchase Agreements

In order to acquire supply resources that ensure reliable natural gas deliveries to its customers, the Terasen Gas companies purchase supply from a select list of producers, aggregators and marketers by adhering to strict standards of counterparty creditworthiness and contract execution and/or management procedures. TGI contracts for approximately 109 PJ of baseload and seasonal supply, of which 80 PJ is delivered off the Spectra Energy Gas transmission system. Approximately 11 PJ is comprised primarily of Alberta-sourced supply transported into British Columbia via TransCanada Pipeline Limited's Alberta and British Columbia systems. The remaining 18 PJ of baseload and seasonal supply is sourced at Sumas, British Columbia. TGVI contracts for approximately 11 PJ of annual supply comprised of base load and seasonal contracts, of which approximately 9 PJ is delivered off the Spectra Energy Gas transmission system and 2 PJ is sourced directly at Sumas.

Through the operation of regulatory deferrals, any difference between forecasted cost of natural gas purchases, as reflected in customer rates, and the actual cost of natural gas purchases is recovered from, or refunded to, customers in future rates. The majority of supply contracts in the current portfolio are seasonal for either the summer period (April to October) or winter period (November to March) with a few contracts one year or longer in length.

The Spectra Energy Gas transmission and TransCanada Pipeline Limited transportation tolls are regulated by the NEB, whose responsibilities include regulating pipeline tolls. The Terasen Gas companies pay both fixed and variable charges for use of the pipelines, which are recovered through rates paid by its customers.

Peak Shaving Arrangements

TGI and TGVI incorporate peak shaving and gas storage facilities into its portfolio to:

i. manage the load factor of baseload supply contracts throughout the year;
ii. eliminate the risk of supply shortages during a peak throughput day;
iii. reduce the cost of gas during winter months; and
iv. balance daily supply and demand on the distribution system.

The Terasen Gas companies' peak shaving and storage assets and contracts for 2010 include up to 30 PJ in storage capacity at various locations throughout British Columbia, Alberta and the Pacific Northwest of the United States. These storage facilities and supply from peak shaving contracts can deliver a maximum daily rate of 562 TJ on a combined basis during the coldest months of December through February.

TGVI maintains storage contracts with Unocal Canada Limited at the Aitken Creek Storage facility in Northern British Columbia and Northwest Natural Gas Company at the Mist Storage facility in Oregon, United States. TGVI's Aitken Creek storage contract consists of 2.1 PJ of capacity with 14.1 TJ of daily deliverability and its Mist storage contract consists of 0.69 PJ of capacity with 26.4 TJ of daily deliverability. TGVI also has access to an estimated 27.0 TJ of daily peak supply deliverability from various peak supply arrangements.

Off-System Sales

TGI is in its fourteenth year of off-system sales activities, in which any daily excess supply of gas is sold at the market-spot rate that allows for the recovery or mitigation of costs on unutilized supply and/or pipeline capacity. In 2008/2009, TGI marketed approximately 23.8 PJ of surplus gas and 41.3 PJ of excess pipeline capacity for a net pre-tax recovery of approximately $136 million. Through the Gas Supply Mitigation Incentive Plan established with the BCUC, $1.1 million (pre-tax) of these benefits accrued to shareholders with the remainder flowing through to customers in the form of reduced natural gas costs.

Unbundling

Over the past several years, TGI, the BCUC and other interested parties have laid the groundwork for the introduction of natural gas commodity unbundling in British Columbia. On November 1, 2004, commercial customers of TGI became eligible to buy their natural gas commodity supply from third-party suppliers. TGI continues to provide delivery of the natural gas. Approximately 80,000 commercial customers are eligible to participate in commodity unbundling. By December 31, 2009, approximately 19,800 customers had elected to participate in this program.

During 2006, the BCUC approved the offering of commodity supply choice to residential customers. The BCUC agreed to open a portion of the province of British Columbia's residential natural gas market to competition, allowing homeowners to sign long-term fixed-price contracts for natural gas with companies other than TGI, effective May 2007. Consumers had the option to remain with TGI or sign with another market participant, in which case they began receiving gas at that market participant's rate beginning in November 2007. TGI continues to provide delivery service to unbundled customers and delivery margins are not expected to be impacted by migration of residential customers to alternative commodity suppliers. Approximately 752,000 residential customers are eligible to participate in commodity unbundling. By December 31, 2009, approximately 118,300 customers had elected to participate in this program. Neither residential nor commercial unbundling has had a material effect on the delivery margins of TGI.

Legal Proceedings

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 CRA for additional taxes related to the taxations years 1999 through 2003. The exposure has been fully provided for in the Corporation's 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 Corporation's 2009 consolidated financial statements.

In 2008, the 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.

Human Resources

As at December 31, 2009, the Terasen Gas companies employed 1,295 full-time equivalent employees. Approximately 68 per cent of the employees are represented by IBEW, Local 213 and COPE, Local 378 under collective agreements that expire on March 31, 2011 and March 31, 2012, respectively.

3.2 Regulated Electric Utilities - Canadian

3.2.1 *FortisAlberta*

FortisAlberta is a regulated electric distribution utility in the province of Alberta. Its business is the ownership and operation of regulated electric distribution facilities that distribute electricity generated by other market participants from high-voltage transmission substations to end-use customers. FortisAlberta is not involved in the generation, transmission or direct sale of electricity. FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, totalling approximately 110,000 kilometres of distribution lines. The Company's distribution network serves approximately 480,000 customers, comprising residential, commercial, farm and industrial consumers of electricity, and met a record peak demand of 3,365 MW in 2009.

Market and Sales

FortisAlberta's annual energy deliveries increased to 15,865 GWh in 2009 from 15,722 GWh in 2008. Revenue was $331 million in 2009 compared to $300 million in 2008.

The following table compares the composition of FortisAlberta's 2009 and 2008 revenue and energy deliveries by customer class.

FortisAlberta
Revenue and Energy Deliveries by Customer Class

	Revenue *(per cent)*		**GWh Deliveries** [(1)] *(per cent)*	
	2009	2008	**2009**	2008
Residential	**30.7**	30.5	**16.9**	16.4
Large commercial and industrial [(2)]	**22.7**	22.6	**60.3**	60.9
Farms	**12.9**	12.9	**8.6**	8.2
Small commercial	**11.4**	11.6	**8.0**	8.0
Small oilfield	**9.4**	9.6	**5.8**	6.0
Other [(3)]	**12.9**	12.8	**0.4**	0.5
Total	**100.0**	100.0	**100.0**	100.0

(1) *GWh percentages presented exclude FortisAlberta's GWh deliveries to "transmission-connected" customers. These deliveries consist primarily of large-scale industrial customers directly connected to the transmission grid. The related transmission revenue is recorded net of expenses in other revenue in FortisAlberta's financial statements.*
(2) *Included in the large commercial and industrial customer class are large oilfield customers*
(3) *Includes revenue from sources other than the delivery of electricity, including that related to street-lighting services, net transmission revenue, rate riders, deferrals and adjustments*

Franchise Agreements

Most of FortisAlberta's residential, commercial and industrial customers, located within a city, town, or village boundary, are served through franchise agreements between the Company and the customers' municipality of residence. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta that are located in their municipal boundaries. In Alberta, the standard franchise agreement, which could include a franchise fee payable to the municipality, is generally for ten years and may be renewed for five years upon mutual consent of the parties. All municipal franchises are governed by legislation that requires the municipality or the utility to give notice and obtain AUC approval if it intends to terminate its franchise agreement. Any franchise agreement that is not renewed continues in effect until either the Company or the municipality terminates it with AUC permission. If a franchise agreement is terminated and the municipality subsequently exercises its right under the *Municipal Government Act* (Alberta) to purchase FortisAlberta's distribution network within the municipality's boundaries or annexed area, the Company must be compensated. Compensation would include payment for FortisAlberta's assets on the basis of replacement cost less depreciation.

FortisAlberta serves 141 municipalities, of which 140 are on standardized individual franchise agreements. Substantially all of these agreements expire between 2011 and 2017. The Company is in the process of renewing or negotiating franchise agreements with one additional municipality and two summer villages.

Human Resources

As at December 31, 2009, FortisAlberta had 996 full-time equivalent employees. Approximately 73 per cent of the employees of the Company are members of a labour association represented by UUWA, Local 200, under a three-year collective agreement that expires on December 31, 2010.

3.2.2 *FortisBC*

FortisBC includes FortisBC Inc., an integrated electric utility that owns a network of generation, transmission and distribution assets located in the southern interior of British Columbia. FortisBC Inc. serves a diverse mix of approximately 159,000 customers, of whom approximately 111,000 are served directly by the Company's assets while the remainder are served through the wholesale supply of power to municipal distributors. In 2009, FortisBC Inc. met a peak demand of 714 MW. Residential customers represent the largest customer segment of the Company. FortisBC's transmission and distribution assets include approximately 7,000 kilometres of transmission and distribution lines and 66 distribution substations.

FortisBC also includes operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Cominco, the 149-MW Brilliant hydroelectric plant and 120-MW Brilliant expansion plant, both owned by CPC/CBT, the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT, and the distribution system owned by the City of Kelowna.

Market and Sales

FortisBC has a diverse customer base composed primarily of residential, general service, industrial and municipal wholesale, and other industrial customers. Annual electricity sales were 3,157 GWh in 2009 compared to 3,087 GWh in 2008. Revenue increased to $253 million in 2009 from $237 million in 2008.

The following table compares the composition of FortisBC's 2009 and 2008 revenue and electricity sales by customer class.

FortisBC
Revenue and Electricity Sales by Customer Class

	Revenue *(per cent)*		**GWh Sales** *(per cent)*	
	2009	2008	**2009**	2008
Residential	**44.0**	43.4	**41.0**	39.5
General service	**24.5**	24.6	**23.2**	23.4
Wholesale	**19.6**	19.3	**29.4**	28.9
Industrial	**5.5**	6.1	**6.4**	8.2
Other [(1)]	**6.4**	6.6	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

[(1)] *Includes revenue from sources other than from the sale of electricity, including revenue of Fortis Pacific Holdings associated with non-regulated operating, maintenance and management services*

Generation and Power Supply

FortisBC Inc. meets the electricity supply requirements of its customers through a mix of its own generation and power purchase contracts. FortisBC Inc. owns four regulated hydroelectric generating plants on the Kootenay River with an aggregate capacity of 223 MW and annual energy output of approximately 1,591 GWh, which provide approximately 45 per cent of the Company's energy needs and 30 per cent of its capacity needs. FortisBC Inc. meets the balance of its requirements through a portfolio of long-term and short-term power purchase agreements.

FortisBC Inc.'s four hydroelectric generating facilities are governed by the CPA. The CPA is a multi-party agreement that enables the five separate owners of eight major hydroelectric generating plants, with a combined capacity of approximately 1,600 MW and located in relatively close proximity to each other, to coordinate the operation and dispatch of their plants.

The following table lists the plants and their owners.

Plant	Capacity (MW)	Owners
Canal Plant	580	BC Hydro
Waneta Dam	493	Teck Cominco
Kootenay River System	223	FortisBC Inc.
Brilliant Dam and Expansion	269	BPC and BEPC
Total	**1,565**	

BPC, BEPC, Teck Cominco and FortisBC Inc. are collectively defined in the CPA as the Entitlement Parties. The CPA enables BC Hydro and the Entitlement Parties, through coordinated use of water flows, subject to the 1961 Columbia River Treaty between Canada and the United States, and storage reservoirs, and through the coordinated operation of generating plants, to generate more power from their respective generating resources than they could if they operated independently. Under the CPA, BC Hydro takes into its system all power actually generated by all seven plants owned by the Entitlement Parties. In exchange for permitting BC Hydro to determine the output of these facilities, each of the Entitlement Parties is contractually entitled to a fixed annual entitlement of capacity and energy from BC Hydro, which is currently based on 50-year historical water flows. The Entitlement Parties receive their defined entitlements irrespective of actual water flows to the Entitlement Parties' generating plants and are, accordingly, insulated from the risk of water availability.

The majority of FortisBC Inc.'s remaining electricity supply is acquired through long-term power purchase contracts, consisting of the following:

i. a 149-MW long-term power purchase agreement with BPC terminating in 2056;
ii. a 200-MW power purchase agreement with BC Hydro terminating in 2013; and
iii. a number of small power purchase contracts with independent power producers.

The majority of these purchase contracts have been approved by the BCUC and prudently incurred costs thereunder flow through to customers through FortisBC Inc.'s electricity rates.

Although FortisBC Inc. can currently meet most of its customer supply requirements from its own generation and the long-term power purchase agreements described above, a portion of the customer load during the summer and winter peak-demand periods may need to be supplied from the market in the form of short-term power purchases. Costs related to such purchases, provided they are prudently incurred and accurately forecasted, are largely flowed through to customers. FortisBC Inc. generally makes arrangements prior to the winter season to acquire power at known prices should the need arise.

Legal Proceedings

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 Inc. 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 Corporation's 2009 consolidated financial statements.

Human Resources

As at December 31, 2009, FortisBC had 540 full-time equivalent employees. FortisBC has a collective agreement with COPE, Local 378, expiring on January 31, 2011, and a collective agreement with IBEW, Local 213, expiring on January 31, 2013. The two collective agreements cover approximately 76 per cent of employees.

3.2.3 *Newfoundland Power*

Newfoundland Power is the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving more than 239,000 customers, or 85 per cent, of the province's electricity consumers. Newfoundland Power met a peak demand of 1,219 MW in 2009. The balance of the population is served by Newfoundland's other electric utility, Newfoundland Hydro, which also serves several larger industrial customers. Newfoundland Power owns and operates approximately 11,000 kilometres of transmission and distribution lines.

Market and Sales

Annual weather-adjusted electricity sales increased to 5,299 GWh in 2009 from 5,208 GWh in 2008. Revenue increased to $527 million in 2009 from $517 million in 2008.

The following table compares the composition of Newfoundland Power's 2009 and 2008 revenue and electricity sales by customer class.

Newfoundland Power
Revenue and Electricity Sales by Customer Class

	Revenue [1] *(per cent)*		**GWh Sales** [1] *(per cent)*	
	2009	2008	**2009**	2008
Residential	**59.0**	58.9	**60.4**	60.1
Commercial and Street Lighting	**37.0**	37.3	**39.6**	39.9
Other [2]	**4.0**	3.8	-	-
Total	**100.0**	100.0	**100.0**	100.0

(1) *Revenue and electricity sales reflect weather-adjusted values pursuant to Newfoundland Power's weather normalization reserve.*
(2) *Includes revenue from sources other than from the sale of electricity, the most significant being joint-use of pole revenue*

Power Supply

Approximately 92 per cent of Newfoundland Power's energy requirements is purchased from Newfoundland Hydro. The principal terms of the supply arrangements with Newfoundland Hydro are regulated by the PUB on a basis similar to that upon which Newfoundland Power's service to its customers is regulated.

Newfoundland Power operates 30 small generating facilities, which generate approximately 8 per cent of the electricity sold by Newfoundland Power. The Company's hydroelectric generating plants have a total capacity of 97 MW. The diesel plants and gas turbines have a total capacity of approximately 7 MW and 36 MW, respectively.

Legal Proceedings

The City of St. John's has given formal notice of its intention to terminate Newfoundland Power's rights to use the Mobile River watershed for the generation of electricity. The effective date of the notice to terminate the lease was March 1, 2009. The Company held these rights under a lease dated November 23, 1946, which was amended by an agreement dated October 21, 1949. The two hydroelectric generating plants affected by the lease have a combined capacity of approximately 12 MW and generate annual production of 49 GWh, representing less than one per cent of the Company's total energy requirements. To exercise the termination provision of the lease, the City of St. John’s is required to pay to the Company the value of all works and erections employed in the generation and transmission of electricity using the water of the Mobile River watershed. In accordance with the terms of the lease, an arbitration panel was appointed in 2008 for the purpose of determining the value of the affected assets. On March 9, 2009, the panel issued a ruling on certain preliminary questions. A majority of the panel ruled that termination of the lease will not be effective until payment to the Company of the value of the assets, and that the value of the payment is to be based on a valuation of the assets as a going concern, including the land and water rights.

The City of St. John’s has applied to the Supreme Court of Newfoundland and Labrador to have the preliminary ruling of the arbitration panel set aside. The application was heard by the Court in June 2009 and a decision is pending.

Human Resources

As at December 31, 2009, Newfoundland Power had 568 full-time equivalent employees, of which approximately 55 per cent were members of bargaining units represented by IBEW, Local 1620.

The Company has two collective agreements governing its union employees represented by IBEW, Local 1620. The collective agreements were ratified in February and April 2009. Both collective agreements expire September 30, 2011.

3.2.4 *Other Canadian Electric Utilities*

Other Canadian Electric Utilities includes the operations of Maritime Electric and FortisOntario.

Maritime Electric

The Corporation, through FortisWest, holds all of the common shares of Maritime Electric. Maritime Electric operates an integrated electric utility that directly supplies approximately 74,000 customers, constituting 90 per cent of electricity consumers on Prince Edward Island. Maritime Electric purchases most of the energy it distributes to its customers from NB Power, a provincial Crown Corporation, through various energy purchase agreements. Maritime Electric’s system is connected to the mainland power grid via two submarine cables between Prince Edward Island and New Brunswick, which are leased from the Government of Prince Edward Island. Maritime Electric owns and operates generating plants with a combined capacity of 150 MW on Prince Edward Island and met a peak demand of 219 MW in 2009. Maritime Electric owns and operates approximately 5,300 kilometres of transmission and distribution lines.

FortisOntario

The Corporation’s wholly owned regulated utility investments in Ontario, collectively FortisOntario, provides integrated electric utility service to approximately 64,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and, as of October 2009, the District of Algoma in Ontario. Included in Canadian Niagara Power’s accounts is the operation of the electricity distribution business of 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 serving approximately 38,000 customers.

FortisOntario met a combined peak demand of 265 MW in 2009. FortisOntario owns and operates approximately 3,300 kilometres of transmission and distribution lines.

Market and Sales

Annual electricity sales were 2,195 GWh in 2009 compared to 2,182 GWh in 2008. Revenue was $279 million in 2009 compared to $262 million in 2008.

The following table compares the composition of Other Canadian Electric Utilities' 2009 and 2008 revenue and electricity sales by customer class.

Other Canadian Electric Utilities
Revenue and Electricity Sales by Customer Class

	Revenue *(per cent)*		**GWh Sales** *(per cent)*	
	2009 *[(1)]*	2008	**2009** *[(1)]*	2008
Residential	**44.1**	43.4	**43.3**	42.4
Commercial and industrial	**48.3**	49.3	**56.1**	57.3
Other [(2)]	**7.6**	7.3	**0.6**	0.3
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes financial results of Algoma Power from October 2009*
(2) *Includes revenue from sources other than from the sale of electricity*

Power Supply

Maritime Electric

Maritime Electric purchased 86 per cent of the electricity required to meet its customers' needs from NB Power in 2009. The balance was met through Maritime Electric's on-Island generation facilities and the purchase of wind energy produced on Prince Edward Island. Maritime Electric's generation facilities are used primarily for peaking, submarine-cable loading issues and emergency purposes.

Maritime Electric generally purchases some of its electricity requirements from Point Lepreau. A major refurbishment began in 2008 and is expected to be completed in early 2011, extending the facility's estimated life an additional 25 years. The cost of replacement energy during the refurbishment of Point Lepreau is expected to be recovered from customers through the operation of the ECAM. To date, replacement energy costs for 2008 have been collected from customers and costs for 2009 have been approved for deferral for future collection from customers, as approved by IRAC.

Legislation proclaimed by the Government of Prince Edward Island will see an increased reliance by Maritime Electric on renewable energy sources, such as wind-powered energy, located on Prince Edward Island. Maritime Electric's goal is that 30 per cent of its annual energy sales be sourced from renewable energy supply by 2013. In 2006, the Company signed an agreement with PEI Energy Corporation that will see the Company purchase 39 MW of wind-powered energy from PEI Energy Corporation's new wind farm. Approximately 14 per cent of total energy supply was derived from wind-powered generation in 2009.

FortisOntario

The power requirements of FortisOntario's service areas are provided from various sources. Canadian Niagara Power purchases its power requirements for Fort Erie and Port Colborne from the IESO. Canadian Niagara Power purchases approximately 73 per cent of energy requirements for Gananoque through monthly energy purchases from Hydro One and the remaining 27 per cent is purchased from six hydroelectric generating plants owned by Fortis Properties. Algoma Power purchases 100 per cent of its energy from the IESO.

Under the Standard Supply Code of the OEB, Canadian Niagara Power is obliged to provide Standard Service Supply to all its customers who do not choose to contract with an electricity retailer. This energy is provided to customers at either regulated or market prices.

Cornwall Electric purchases 100 per cent of its power requirements from Hydro-Québec Energy Marketing under two fixed-term contracts. The first contract, which represents approximately 37 per cent of the power supply, is a 45-MW contract with a 60 per cent capacity factor. The second contract, supplying the remainder of Cornwall Electric's energy requirement, is a 100-MW capacity and energy contract. Both contracts expire in December 2019.

Legal Proceedings

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.

Human Resources

As at December 31, 2009, Maritime Electric had 179 full-time equivalent employees, of which approximately 70 per cent were represented by IBEW, Local 1432. The collective agreement with IBEW, Local 1432, expired in December 2008. In February 2010, a new collective agreement, which expires December 31, 2013, was ratified by the union.

As at December 31, 2009, FortisOntario had 184 full-time equivalent employees, of which approximately 64 per cent were represented by CUPE, Local 137 and IBEW, Local 636, in the Niagara Region; IBEW, Local 636, in Gananoque; and PWU in the Algoma region. The collective agreements governing these employees expire, or expired, on April 30, 2012, May 31, 2012, July 31, 2012, and December 31, 2009, respectively. Algoma Power and PWU are currently negotiating a new collective agreement.

3.3 Regulated Electric Utilities - Caribbean

Regulated Electric Utilities - Caribbean operations are comprised of Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos.

Belize Electricity, the principal distributor of electricity in Belize, Central America, serves approximately 76,000 customers, owns more than 2,900 kilometres of transmission and distribution lines and met a peak demand of 76 MW in 2009. The Corporation holds an approximate 70 per cent controlling ownership interest in Belize Electricity.

Caribbean Utilities is the sole provider of electricity on Grand Cayman, Cayman Islands, serving more than 25,000 customers. The Company met a record peak demand of approximately 97.5 MW in 2009.

Caribbean Utilities owns and operates approximately 555 kilometres of transmission and distribution lines. Fortis holds an approximate 59 per cent controlling ownership interest in the utility. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U).

Fortis Turks and Caicos, wholly owned by Fortis, serves more than 9,000 customers, or 85 per cent, of electricity consumers, in the Turks and Caicos Islands and met a combined record peak demand of 29.6 MW in 2009. Fortis Turks and Caicos owns and operates approximately 235 kilometres of transmission and distribution lines. The Company is the principal distributor of electricity in the Turks and Caicos Islands pursuant to 50-year licences that expire in 2036 and 2037.

Market and Sales

Annual electricity sales decreased to 1,140 GWh in 2009 from 1,203 GWh in 2008. Annual revenue decreased to $339 million in 2009 from $408 million in 2008. Electricity sales and revenue for 2008, however, included electricity sales and revenue of Caribbean Utilities for the 14 months ended December 31, 2008, due to a change in the utility's fiscal year end in 2008.

The following table compares the composition of Regulated Electric Utilities - Caribbean's revenue and electricity sales by customer class for the years ended 2009 and 2008.

Regulated Electric Utilities – Caribbean [(1)] [(2)]
Revenue and Electricity Sales by Customer Class

	Revenue [(3)] *(per cent)*		**GWh Sales** [(3)] *(per cent)*	
	2009	2008	**2009**	2008
Residential	**48.0**	46.7	**48.4**	47.3
Commercial, industrial and street lighting	**50.0**	51.3	**51.6**	52.7
Other [(4)]	**2.0**	2.0	-	-
Total	**100.0**	100.0	**100.0**	100.0

(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, which has resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities during 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) *Iincludes 100 per cent of the revenue and electricity sales of Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos.*
(4) *Includes revenue from sources other than from the sale of electricity*

Power Supply

In 2009, 65 per cent of the energy demand of Regulated Electric Utilities - Caribbean was sourced from gas turbine and diesel-powered generation. The majority of the remaining energy demand was sourced from hydroelectric generating facilities in Belize and purchased from CFE.

Belize Electricity meets its energy demand from multiple sources, which include power purchases from: (i) the Mollejon and Chalillo hydroelectric generating facilities owned and operated by BECOL; (ii) CFE, the Mexican state-owned power company; (iii) the Hydro Maya hydroelectric generating plant owned by Hydro Maya Limited; (iv) the heavy fuel oil plant operated by BAL; (v) the cogeneration facility owned by BELCOGEN; and (vi) its own diesel-powered and gas-turbine generation. All major load centers are connected to Belize's national electricity system, which is connected with the Mexican national electricity grid, allowing Belize Electricity to optimize its power supply options. Belize Electricity purchased and produced 473 GWh of electricity in 2009, of which 96 per cent was purchased from the Mollejon and Chalillo hydroelectric generating facilities, CFE, Hydro Maya Limited, BAL and BELCOGEN. The balance was produced by Belize Electricity's installed generating capacity of 34 MW, including a 22-MW gas-turbine generating facility.

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 expire 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 shortfall 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.

Caribbean Utilities relies upon diesel-powered generation to produce electricity for Grand Cayman. Grand Cayman has neither hydroelectric potential nor inherent thermal resources and the Company must rely upon diesel fuel imported to Grand Cayman primarily from refineries in the Caribbean and the Gulf of Mexico. The Company has an installed generating capacity of approximately 153 MW.

Fortis Turks and Caicos relies upon diesel-powered generation, which has a combined generating capacity of 54 MW, to produce electricity for its customers.

Legal Proceedings

Belize Electricity is involved in a number of legal proceedings relating to the PUC's Final Decision on Belize Electricity's 2008/2009 Rate Application. For further information, refer to the "Regulation - Material Regulatory Decisions and Applications" section of this 2009 Annual Information Form.

Human Resources

As at December 31, 2009, Regulated Electric Utilities - Caribbean employed 593 full-time equivalent employees. The 196 employees at Caribbean Utilities and 105 employees at Fortis Turks and Caicos are non-unionized. Of the 292 full-time equivalent employees at Belize Electricity, approximately 51 per cent were represented by BEWU. The Company's collective agreement with BEWU was signed in July 2008 and is to be reviewed every five years.

3.4 Non-Regulated - Fortis Generation

The following table summarizes the Corporation's non-regulated generation assets by location.

Fortis Generation
Non-Regulated Generation Assets

Location	Plants	Fuel	Capacity (MW)
Belize [(1)]	3	hydro	51
Ontario	7	hydro, thermal	13
Central Newfoundland [(2)]	2	hydro	36
British Columbia	1	hydro	16
Upper New York State	4	hydro	23
Total	**17**		**139**

(1) *Includes the 19-MW Vaca hydroelectric generating facility, which will be commissioned in March 2010.*
(2) *The two central Newfoundland plants were expropriated by the Government of Newfoundland and Labrador in December 2008. Effective February 12, 2009, the Corporation discontinued the consolidation method of accounting for its investment in central Newfoundland.*

The Corporation's non-regulated generation operations consist of its 100 per cent ownership interest in each of BECOL, FortisOntario and FortisUS Energy, as well as non-regulated generation assets owned by Fortis Properties and FortisBC Inc.

Non-regulated generation operations in Belize consist of the operations of the 25-MW Mollejon, the 7-MW Chalillo and, as of March 2010, the 19-MW Vaca hydroelectric generating facilities. All of the output of these facilities is sold to Belize Electricity under 50-year power purchase agreements expiring in 2055 and 2060 and a franchise agreement with the Government of Belize. Under these agreements, the Mollejon hydroelectric generating facility will be transferred to the Government of Belize in 2036, after which it will be leased at an annually increasing rate for a term expiring in 2055.

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 was constructed downstream from the Chalillo and Mollejon hydroelectric generation facilities and is expected to increase average annual energy production from the Macal River by approximately 80 GWh to 240 GWh.

Non-regulated generation operations of FortisOntario include the operation of a 5-MW gas-powered cogeneration plant in Cornwall. The 75 MW water-right entitlement associated with the Rankine hydroelectric generating facility in Ontario expired on April 30, 2009, at the end of a 100-year term. Fortis Properties, a non-regulated wholly owned subsidiary, operates six small hydroelectric generating facilities in eastern Ontario with a combined capacity of 8 MW.

Fortis Properties also has non-regulated generation operations in central Newfoundland that are conducted through the Corporation's indirect 51 per cent interest in the Exploits Partnership. Through the Exploits Partnership, 36 MW of additional capacity was developed and installed at two of Abitibi's hydroelectric generating plants in central Newfoundland. The Exploits Partnership sells its output to Newfoundland Hydro under a 30-year power purchase agreement expiring in 2033. Effective February 12, 2009, the Corporation discontinued the consolidation method of accounting for these operations, necessitated by the actions of the Government of Newfoundland and Labrador related to its expropriation of the assets of the Exploits Partnership (see the "Legal Proceedings" section that follows).

The non-regulated generation operations of FortisBC Inc., conducted through Walden, its wholly owned partnership, consist of the 16-MW run-of-river hydroelectric generating plant near Lillooet, British Columbia. This plant is a non-regulated operation that sells its entire output to BC Hydro under a power purchase agreement expiring in 2013.

Through FortisUS Energy, an indirect wholly owned subsidiary, the Corporation owns and operates four hydroelectric generating facilities in Upper New York State with a combined capacity of approximately 23 MW operating under licences from FERC. All four hydroelectric generating facilities sell energy at current market rates.

Market and Sales

Annual energy sales from non-regulated generation assets were 583 GWh in 2009 compared to 1,217 GWh in 2008. Revenue was $39 million in 2009 compared to $82 million in 2008. Revenue and energy sales for 2009 included 4 months of revenue and energy sales associated with the Rankine hydroelectric facility in Ontario compared to 12 months in 2008, due to the expiration of the Rankine water rights in April 2009. Revenue and energy sales for 2009 reflected contribution from central Newfoundland operations for only 1½ months compared to an entire year in 2008 (see "Legal Proceedings" section that follows).

The following table compares the composition of Fortis Generation's 2009 and 2008 revenue and energy sales by location.

Fortis Generation Revenue and Energy Sales by Location				
	Revenue *(per cent)*		**GWh Sales** *(per cent)*	
	2009	2008	**2009**	2008
Belize	**46.1**	20.8	**30.9**	15.8
Ontario [(1)]	**31.0**	42.7	**46.5**	58.8
Central Newfoundland [(2)]	**9.1**	25.6	**3.3**	14.6
British Columbia	**4.2**	2.2	**4.9**	2.7
Upper New York State	**9.6**	8.7	**14.4**	8.1
Total	**100.0**	100.0	**100.0**	100.0

(1) *Reflects revenue and energy sales associated with the Rankine hydroelectric facility until April 30, 2009*
(2) *Reflects the discontinuance of the consolidation method of accounting for the financial results of the operations in central Newfoundland, effective February 12, 2009*

Legal Proceedings

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.

Human Resources

At December 31, 2009, Fortis Generation employed 29 full-time equivalent personnel, none of whom participate in a collective agreement.

3.5 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. As a wholly owned subsidiary of Fortis, Fortis Properties is the Corporation's vehicle for non-utility diversification and growth.

Revenue was $218 million in 2009 compared to $207 million in 2008. In 2009, Fortis Properties derived approximately 29 per cent of its revenue from real estate operations and 71 per cent of its revenue from hotel operations. Fortis Properties derived approximately 44 per cent of its 2009 operating income from real estate operations and 56 per cent from hotel operations.

Fortis Properties' Real Estate Division is anchored by high-quality tenants under long-term leases. The Real Estate Division ended 2009 with 96.2 per cent occupancy, slightly below the rate of 96.8 per cent as at the end of 2008. In contrast, the average national occupancy rate was 90.2 per cent at the end of 2009, compared to 93.3 per cent at the end of 2008.

The following table sets out the office and retail properties owned by Fortis Properties.

Fortis Properties
Office and Retail Properties

Property	**Location**	**Type of Property**	**Gross Lease Area** *(square feet 000s)*
Fort William Building	St. John's, NL	Office	188
Cabot Place I	St. John's, NL	Office	135
TD Place	St. John's, NL	Office	94
Fortis Building	St. John's, NL	Office	83
Multiple Office	St. John's, NL	Office and Retail	75
Millbrook Mall	Corner Brook, NL	Retail	118
Fraser Mall	Gander, NL	Retail	99
Marystown Mall	Marystown, NL	Retail	87
Fortis Tower	Corner Brook, NL	Office	69
Viking Mall	St. Anthony, NL	Retail	69
Maritime Centre	Halifax, NS	Office and Retail	564
Brunswick Square	Saint John, NB	Office and Retail	512
Kings Place	Fredericton, NB	Office and Retail	292
Blue Cross Centre	Moncton, NB	Office and Retail	324
Delta Regina	Regina, SK	Office	52
Total			**2,761**

Revenue per available room, at the Hospitality Division of Fortis Properties, decreased for the first time in 14 years to $76.55 in 2009 from $80.39 in 2008. National revenue per available room declined 12.3 per cent for 2009 compared to 2008. The decrease was the result of lower average occupancy in 2009 mainly due to the impact of the economic downturn, partially offset by an increase in average room rates. Average occupancy for 2009 was 62.8 per cent down from the 66.9 per cent achieved in 2008, while the average daily room rate increased to $121.98 in 2009 up from $120.23 in 2008.

In April 2009, Fortis Properties acquired the Holiday Inn Select Windsor in Ontario. The hotel has 214 rooms and 14,000 square feet of meeting and banquet space.

The hotels owned and managed by Fortis Properties are summarized as follows.

Fortis Properties Hotels			
Hotels	**Location**	**Number of Guest Rooms**	**Conference Facilities** *(000's square feet)*
Delta St. John's	St. John's, NL	403	21
Holiday Inn St. John's	St. John's, NL	252	11
Sheraton Hotel Newfoundland	St. John's, NL	301	16
Mount Peyton	Grand Falls-Windsor, NL	148	4
Greenwood Inn Corner Brook	Corner Brook, NL	102	5
Four Points by Sheraton Halifax	Halifax, NS	177	12
Delta Sydney	Sydney, NS	152	6
Delta Brunswick	Saint John, NB	254	18
Holiday Inn Kitchener-Waterloo	Kitchener-Waterloo, ON	184	13
Holiday Inn Peterborough	Peterborough, ON	153	7
Holiday Inn Sarnia	Point Edward, ON	217	11
Holiday Inn Cambridge	Cambridge, ON	143	7
Holiday Inn Select Windsor	Windsor, ON	214	14
Greenwood Inn Calgary	Calgary, AB	210	9
Greenwood Inn Edmonton	Edmonton, AB	224	8
Greenwood Inn Winnipeg	Winnipeg, MB	213	10
Ramada Hotel & Suites Lethbridge	Lethbridge, AB	119	5
Holiday Inn Express and Suites Medicine Hat	Medicine Hat, AB	93	1
Best Western Medicine Hat	Medicine Hat, AB	122	-
Holiday Inn Express Kelowna (1)	Kelowna, BC	190	5
Delta Regina	Regina, SK	274	24
Total		**4,145**	**207**

(1) *Includes an additional 70 rooms and approximately 4,500 square feet of meeting space associated with an expansion of the hotel completed in February 2010*

Human Resources

As at December 31, 2009, Fortis Properties employed approximately 2,300 full-time equivalent employees, approximately 50 per cent of whom are represented by unions listed in the following table.

Fortis Properties Unions			
Property	**Union**	**Expiry of Agreement**	**Number of Unionized Employees**
Holiday Inn St. John's	CAW	August 31, 2012	52
Delta St. John's	UFCW	December 31, 2009 (1)	255
Greenwood Inn Corner Brook	CAW	March 11, 2010	43
East Side Mario's St. John's	CAW	July 31, 2010	100
Delta Sydney	CAW	September 30, 2011	81
Delta Brunswick & Brunswick Square	USW	June 10, 2010	150
Delta Regina	CEP	November 30, 2010	171
St. John's Real Estate	IBEW	April 17, 2010	11
Sheraton Hotel Newfoundland	CAW	March 31, 2011	180
Holiday Inn Select Windsor	UFCW	April 30, 2010	52
Mount Peyton	UFCW	December 1, 2011	54
Total			**1,149**

(1) *Collective bargaining is expected to begin before the end of the second quarter of 2010.*

4.0 REGULATION

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 (%) 2008	Allowed Returns (%) 2009	Allowed Returns (%) 2010	Supportive Features: Future or Historical Test Year Used to Set Customer Rates
			ROE			COS/ROE
TGI	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	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	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	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	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	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 liquefied natural gas 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 Kootneys; (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 the 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 CPI for British Columbia minus a 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. • 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.

Material Regulatory Decisions and Applications (cont'd)	
Regulated Utility (cont'd)	**Summary Description (cont'd)**
FortisBC (cont'd)	• 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.
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 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 ECAM. Additionally, IRAC approved the deferral of 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.

Material Regulatory Decisions and Applications (cont'd)	
Regulated Utility (cont'd)	**Summary Description (cont'd)**
Maritime Electric (cont'd)	• 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 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.
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.

Material Regulatory Decisions and Applications (cont'd)	
Regulated Utility (cont'd)	**Summary Description (cont'd)**
Caribbean Utilities	• In March 2009, the ERA approved the Company's 2009 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 US$59 million for estimated costs associated with future generation expansion that is expected 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.

5.0 ENVIRONMENTAL MATTERS

The Corporation and its Canadian subsidiaries are subject to federal, provincial and municipal laws, regulations and guidelines relating to the protection of the environment including, but not limited to, wildlife, water and land protection and the proper storage, transportation, recycling and disposal of hazardous and non-hazardous substances. In addition, both the provincial and federal governments have environmental assessment legislation, which is designed to foster better land-use planning through the identification and mitigation of potential environmental impacts of projects or undertakings prior to and after their commencement.

Several key Canadian federal environmental laws and regulations affecting the operations of the Corporation's Canadian subsidiaries include, but are not limited to, the: (i) *Canadian Environmental Assessment Act;* (ii) *Canadian Environmental Protection Act*; (iii) *Transportation of Dangerous Goods Act and Regulations*; (iv) *Hazardous Product Act*; (v) *Canada Wildlife Act*; (vi) *Navigable Waters Protection Act*; (vii) *Canada National Parks Act*; (viii) *Fisheries Act; (ix) Canada Water Act; (x) National Emission Guidelines for Stationary Combustion Turbines; (xi) National Fire Code of Canada; (xii) Pest Control Products Act and Regulations; (xiii) Storage of PCB Material Regulations; (xiv) Canadian Species at Risk Act; and (xv) Ozone Depleting Substances Regulations.*

There are many Canadian provincial and municipal laws, regulations and guidelines that address similar environmental risks as the federal laws, regulations and guidelines, but at a local level.

In British Columbia, the *Carbon Tax Act* and *Greenhouse Gas Reduction Targets Act* specifically affect, or may potentially affect, the operations of the Terasen Gas companies and FortisBC as is described later in this section.

While there are environmental laws, regulations and guidelines affecting the Corporation's operations in Grand Cayman, Turks and Caicos, and Belize, they are less extensive than the laws, regulations and guidelines in Canada.

Environmental risks affecting the Corporations' utility operations include, but are not limited to: (i) hazards associated with the storage and handling of large volumes of fuel at fuel-powered electricity generating plants, including leeching of the fuel into the ground and nearby watershed areas; (ii) risk of spilling or leaking petroleum-based products, including PCB-contaminated oil, which are used in the cooling and lubrication of transformers, capacitors and other electrical equipment; (iii) greenhouse gas emissions, including natural gas and propane leaks and spills and emissions from the combustion of fuel required to generate electricity; (iv) risk of fire; (v) risk of contamination of air, soil or land associated with the improper handling, storage, transportation and disposal of other hazardous substances; (vi) risk of disruption to vegetation; (vii) risk of contamination of soil and water near chemically treated poles; (viii) risk of disruption to fish, animals and their habitat as a result of the creation of artificial water flows and levels associated with hydroelectric water storage and utilization; and (ix) risk of responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner.

The key focus of the utilities is to provide reliable cost-effective service with full regard for the safety of employees and the public while operating in an environmentally responsible manner. A focus on safety and the environment is, therefore, an integral and continuing component of the Corporation's operating activities. The environmental policies vary among the Corporation's utilities depending on the specific environmental laws, regulations and guidelines applicable to their operations and jurisdiction. However, the policies are implemented and reinforced through the use of environmental management systems. Common elements of the utilities' environmental management systems include: (i) regular inspections of fuel- and oil-filled equipment in order to identify and correct for potential spills, and spill response systems to ensure that all spills are addressed, and the associated cleanup is conducted in a prompt and environmentally responsible manner; (ii) greenhouse gas emissions management; (iii) procedures for handling, transporting, storing and disposing of hazardous substances, including chemically treated poles, asbestos, lead and mercury; (iv) programs to mitigate fire-related incidents; (v) programs for the management and/or elimination of PCBs; (vi) vegetation management programs; (vii) training and communicating of environmental policies to employees to ensure work is conducted in an environmentally responsible manner; (viii) review of work practices that affect the environment; (ix) waste management programs; (x) environmental emergency response procedures; (xi) environmental site assessments; and (xii) environmental incident reporting procedures.

The Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and FortisOntario have developed their respective environmental management systems consistent with the guidelines of ISO 14001, an internationally recognized standard for environmental management systems. Caribbean Utilities operates an environmental management system associated with its generation operations, which is ISO 14001 certified, and uses an environmental management system for its transmission and distribution operations, which is consistent with ISO 14001 guidelines. Belize Electricity has implemented an environmental management system with the intention of it becoming consistent with ISO 14001 guidelines by the end of 2010. Fortis Turks and Caicos plans to have an environmental management system fully implemented by 2012, which will be consistent with ISO 14001 guidelines. As part of their respective environmental management system, the utilities are continuously establishing and implementing programs and procedures to identify potential environmental impacts, mitigate those impacts and monitor performance. External and/or internal audits of the environmental management systems are performed on a periodic basis. Based on audits completed in 2009, the environmental management systems continue to be effective and materially consistent with ISO 14001 guidelines.

Environmental risks associated with the Corporation’s non-regulated generation operations are either addressed by environmental management systems of the Corporation’s regulated electric utilities or by environmental practices and procedures followed by Fortis Properties.

For the Corporation’s regulated gas utilities, air emissions management is the main environmental concern primarily due to the uncertainties relating to emerging federal and provincial greenhouse gas regulations. While governmental policy direction is unfolding, it remains to be determined to what extent a greenhouse air emissions cap will impact these utilities. To help mitigate this uncertainty, the Terasen Gas companies participate in sectoral and industry groups to develop the emerging regulation. In addition, TGI was an active participant in Canada’s Voluntary Climate Change Challenge and Registry and, its successor, the Canadian Greenhouse Gas Challenge Registry.

Recent updates to the Government of British Columbia’s Energy Plan and greenhouse gas reduction targets present risks and opportunities to the Terasen Gas companies and, to a lesser degree, FortisBC. The *Greenhouse Gas Reduction Targets Act* mandates a province-wide reduction in greenhouse gases of 33 per cent from 2007 levels by 2010. This is coupled with mandates for all new electricity generation to be net carbon neutral, and for British Columbia to be electrically self-sufficient by 2016.

Energy and emissions policies in British Columbia also present a number of opportunities. The policies have created incentives to expand Terasen’s deployment of renewable energy, such as biogas, and to expand the Company’s Energy Efficiency and Conservation Program. Additionally, the introduction of the *Carbon Tax Act* improves the position of natural gas relative to other fossil energy, as the tax is based on the amount of carbon dioxide equivalent emitted per unit energy. Natural gas, therefore, has a lower tax rate than oil or coal products.

British Columbia is a participant in the Western Climate Initiative. The participants, consisting of several states and provinces, plan to implement a cap-and-trade program to reduce greenhouse gas emissions. The program begins on January 1, 2012. Terasen expects to have two facilities covered under this program; TGI and TGVI . The specific details outlining which facilities will be captured are dependent on what types of emissions are covered, and how individual facilities will be defined under cap and trade legislation. The cap and trade program will have a declining cap on emissions that all covered facilities must meet, either by reducing emissions internally or by purchasing allowances from other facilities for releases over the capped amounts. While allowance costs are based on market prices that have little clarity at present, it appears likely that these facilities will be net purchasers of allowances over the near and medium terms. Allowances will likely be issued to mirror the emission reduction mandate of the Government of British Columbia, such that emissions will need to be reduced by 33 per cent over 2007 amounts by 2020.

The key environmental risks affecting the Corporation's hospitality and real estate operations include, but are not limited to: (i) risk of asbestos and urea-formaldehyde contamination in buildings; (ii) risk of release of ozone-depleting substances from air conditioning and refrigeration equipment; (iii) fuel tank leaks; and (iv) risk of responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. Fortis Properties is committed to meeting the requirements of environmental standards related to its hospitality and real estate operations. In assessing new properties, all buildings and hotels must meet environmental standards, including, but not limited to, the appropriate federal, provincial and municipal standards for asbestos, fuel storage, urea-formaldehyde and chlorofluorocarbon-based refrigerants in air conditioning and refrigerating equipment. This process is also applied to existing properties, ensuring environmental compliance by all facilities.

The Corporation has asset-retirement obligations as disclosed in the Notes to the 2009 consolidated financial statements of Fortis. However, liabilities with respect to these asset-retirement obligations have not been recorded in the Corporation's 2009 consolidated financial statements as they could not be reasonably estimated or were determined to be immaterial (including asset-retirement obligations associated with PCBs, asbestos and chemically treated poles) to the Corporation's consolidated results of operations, cash flows or financial position.

Costs associated with environmental protection initiatives (including the development, implementation and maintenance of environmental management systems), compliance with environmental laws, regulations and guidelines, and environmental damage did not materially affect the Corporation's consolidated results of operations, cash flows or financial position and, based on current laws, facts and circumstances, are not expected to have a material effect in the future. At the Corporation's regulated utilities, prudently incurred operating and capital costs associated with environmental protection initiatives, compliance with environmental laws, regulations and guidelines, and environmental damage are eligible for recovery in customer rates. The Corporation believes that it and its subsidiaries are materially compliant with environmental laws and regulations applicable to them in the various jurisdictions in which they operate.

For further information on the Corporation's environmental risk factors, refer to the "Risk Factors - Environmental Risks" section of this 2009 Annual Information Form.

6.0 RISK FACTORS

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 "Risk Factors - Interest Rate Risk" section of this 2009 Annual Information Form.

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.

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, 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 "Risk Factors - Insurance Coverage Risk" section of this 2009 Annual Information Form 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 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. 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.

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 transmission and distribution 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 transmission and distribution 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 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 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 "Risk Factors - Derivative Financial Instruments and Hedging" section of this 2009 Annual Information Form, 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.

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 "Risk Factors - Economic Conditions" section of this 2009 Annual Information Form.

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 "Risk Factors - Risks Related to TGVI" and "Risk Factors - Government of British Columbia's Energy Plan" sections of this 2009 Annual Information Form.

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.

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 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 (see also, "Regulated Gas Utilities - Terasen Gas companies - Legal Proceedings" section of this 2009 Annual Information Form). 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 "Risk Factors - Insurance Coverage Risk" section of this 2009 Annual Information Form.

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.

For further information on environmental matters pertaining to the Corporation, refer to the "Environmental Matters" section of this 2009 Annual Information Form.

Insurance Coverage Risk: While the Corporation and its subsidiaries maintain insurance, a significant portion of the Corporation's regulated electric utilities' transmission and distribution 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 IESO 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 IFRS: Effective January 1, 2011, Canadian publicly accountable enterprises are required to adopt IFRS as issued by the 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* 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.

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 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 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. 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.

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.

7.0 GENERAL DESCRIPTION OF SHARE CAPITAL STRUCTURE

The authorized share capital of the Corporation consists of the following:

(a) an unlimited number of Common Shares without nominal or par value;
(b) an unlimited number of First Preference Shares without nominal or par value; and
(c) an unlimited number of Second Preference Shares without nominal or par value.

At March 5, 2010, the following Common Shares and First Preference Shares were issued and outstanding.

Share Capital	Issued and Outstanding	Votes per Share
Common Shares	172,050,701	One
First Preference Shares, Series C	5,000,000	None
First Preference Shares, Series E	7,993,500	None
First Preference Shares, Series F	5,000,000	None
First Preference Shares, Series G	9,200,000	None
First Preference Shares, Series H	10,000,000	None

The following table summarizes the cash dividends declared per share for each of the Corporation's class of share for the past three years.

	Dividends Declared *(per share)*		
Share Capital	**2007**	**2008**	**2009**
Common Shares	$0.88	$1.01	$0.78
First Preference Shares, Series C	$1.3625	$1.3625	$1.3625
First Preference Shares, Series E	$1.2250	$1.2250	$1.2250
First Preference Shares, Series F	$1.2250	$1.2250	$1.2250
First Preference Shares, Series G [(1)]	-	$1.0184	$1.3125
First Preference Shares, Series H [(2)]	-	-	-

[(1)] *The First Preference Shares, Series G were issued in May and June 2008.*
[(2)] *The First Preference Shares, Series H were issued in January 2010, and are initially entitled to receive cumulative dividends in the amount of $1.0625 per annum.*

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.

On January 11, 2010, the Board declared an increase in the quarterly Common Share dividend to $0.28 per share from $0.26 per share, with the first payment occurring on March 1, 2010, to holders of record as of February 5, 2010. Also on January 11, 2010, the Board declared a first quarter 2010 dividend on the First Preference Shares, Series C, E, F and G in accordance with the applicable annual prescribed rate and was paid on March 1, 2010 to holders of record as of February 5, 2010.

On March 2, 2010, the Board declared a second quarter 2010 dividend of $0.28 per Common Share and a second quarter 2010 dividend on the First Preference Shares, Series C, E, F, G and H in accordance with the applicable annual prescribed rate. The first dividend associated with the First Preference Shares, Series H will be in the amount of $0.3668 per share to be paid on June 1, 2010. In each case, the second quarter 2010 dividends will be paid on June 1, 2010 to holders of record as of May 7, 2010.

Common Shares

Dividends on Common Shares are declared at the discretion of the Board. Holders of Common Shares are entitled to dividends on a pro rata basis if, as, and when declared by the Board. Subject to the rights of the holders of the First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive dividends in priority to or rateably with the holders of the Common Shares, the Board may declare dividends on the Common Shares to the exclusion of any other class of shares of the Corporation.

On the liquidation, dissolution or winding-up of Fortis, holders of Common Shares are entitled to participate rateably in any distribution of assets of Fortis, subject to the rights of holders of First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution in priority to or rateably with the holders of the Common Shares.

Holders of the Common Shares are entitled to receive notice of and to attend all annual and special meetings of the shareholders of Fortis, other than separate meetings of holders of any other class or series of shares, and are entitled to one vote in respect of each Common Share held at such meetings.

First Preference Shares, Series C

The 5,000,000 First Preference Shares, Series C are entitled to fixed cumulative preferential cash dividends at a rate of $1.3625 per share per annum. On or after June 1, 2010, the Corporation may, at its option, redeem for cash the First Preference Shares, Series C, in whole at any time, or in part from time to time, at $25.75 per share if redeemed before June 1, 2011; at $25.50 per share if redeemed on or after June 1, 2011 but before June 1, 2012; at $25.25 per share if redeemed on or after June 1, 2012 but before June 1, 2013; and at $25.00 per share if redeemed on or after June 1, 2013 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption. On or after June 1, 2010, the Corporation may, at its option, convert all, or from time to time, any part of the outstanding First Preference Shares, Series C into fully paid and freely tradable Common Shares of the Corporation. The number of Common Shares into which each Preference Share may be so converted will be determined by dividing the then-applicable redemption price per Preference Share, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95 per cent of the then-current market price of the Common Shares. On or after September 1, 2013, each First Preference Share, Series C will be convertible at the option of the holder on the first day of September, December, March and June of each year into freely tradable Common Shares determined by dividing $25.00, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95 per cent of the then-current market price of the Common Shares. If a holder of First Preference Shares, Series C elects to convert any of such shares into Common Shares, the Corporation can redeem such First Preference Shares, Series C for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares, Series E

The 7,993,500 First Preference Shares, Series E are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. On or after June 1, 2013, the Corporation may, at its option, redeem all, or from time to time any part of, the outstanding First Preference Shares, Series E by the payment in cash of a sum per redeemed share equal to $25.75 if redeemed during the 12 months commencing June 1, 2013; $25.50 if redeemed during the 12 months commencing June 1, 2014; $25.25 if redeemed during the 12 months commencing June 1, 2015; and $25.00 if redeemed on or after June 1, 2016 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption. On or after June 1, 2013, the Corporation may, at its option, convert all, or from time to time any part of the outstanding First Preference Shares, Series E into fully paid and freely tradable Common Shares of the Corporation.

The number of Common Shares into which each Preference Share may be so converted will be determined by dividing the then-applicable redemption price per First Preference Share, Series E, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95 per cent of the then-current market price of the Common Shares at such time. On or after September 1, 2016, each First Preference Share, Series E will be convertible at the option of the holder on the first business day of September, December, March and June of each year, into fully paid and freely tradable Common Shares determined by dividing $25.00, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95 per cent of the then-current market price of the Common Shares. If a holder of First Preference Shares, Series E elects to convert any of such shares into Common Shares, the Corporation can redeem such First Preference, Shares E for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares, Series F

The 5,000,000 First Preference Shares, Series F are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. On or after December 1, 2011, the Corporation may, at its option, redeem for cash the First Preference Shares, Series F, in whole at any time or in part from time to time, at $26.00 per share if redeemed before December 1, 2012; at $25.75 per share if redeemed on or after December 1, 2012 but before December 1, 2013; at $25.50 per share if redeemed on or after December 1, 2013 but before December 1, 2014; at $25.25 per share if redeemed on or after December 1, 2014 but before December 1, 2015; and at $25.00 per share if redeemed on or after December 1, 2015 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series G

The 9,200,000 First Preference Shares, Series G are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.3125 per share per annum for each year up to and including August 31, 2013. For each five-year period after that 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 the $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 per cent. 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.

First Preference Shares, Series H

The 10,000,000 First Preference Shares, Series H are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.0625 per share per annum for each year up to but excluding June 1, 2015. For each five-year period after that date, the holders of First Preference Shares, Series H are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 1.45 per cent.

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

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

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

On any Series H Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series H outstanding, such remaining First Preference Shares, Series H will automatically be converted into an equal number of First Preference Shares, Series I. On any Series I Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series I outstanding, such remaining First Preference Shares, Series I will automatically be converted into an equal number of First Preference Shares, Series H. However, if such automatic conversions would result in less than 1,000,000 Series I First Preference Shares or less than 1,000,000 Series H First Preference Shares outstanding then no automatic conversion would take place.

Convertible Debentures

The Corporation's US$40 million 5.50% Unsecured Subordinated Convertible Debentures, due 2016, are redeemable by the Corporation 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 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. There is no provision associated with these debentures that restricts the payment of dividends.

Debt Covenant Restrictions on Dividend Distributions

The Trust Indenture pertaining to the Corporation's $100 million Senior Unsecured Debentures contains a covenant which provides that Fortis shall not declare or pay any dividends (other than stock dividends or cumulative preferred dividends on preferred shares not issued as stock dividends) or make any other distribution on its shares if, immediately thereafter, its consolidated funded obligations would be in excess of 75 per cent of its total consolidated capitalization.

The Trust Indenture pertaining to the Corporation's $200 million Senior Unsecured Debentures contains a covenant which provides that Fortis shall not declare or pay any dividends (other than stock dividends or cumulative preferred dividends on preferred shares not issued as stock dividends) or make any other distribution on its shares or redeem any of its shares or prepay Subordinated Debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75 per cent of its total consolidated capitalization.

The Corporation has a $600 million unsecured committed revolving credit facility, maturing in May 2012, that can be used for general corporate purposes, including acquisitions. The credit facility contains a covenant which provides that Fortis shall not declare or pay any dividends or make any other restricted payments if, immediately thereafter, consolidated debt to consolidated capitalization ratio would exceed 70 per cent at any time.

As at December 31, 2009 and 2008, the Corporation was in compliance with its debt covenant restrictions pertaining to dividend distributions, as described above.

8.0 CREDIT RATINGS

Securities issued by Fortis and its currently rated utilities are rated by one or more credit rating agencies, namely, DBRS, S&P and/or Moody's. The ratings assigned to securities issued by Fortis and its currently rated utilities are reviewed by the agencies on an ongoing basis. Credit ratings and stability ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are not recommendations to buy, sell or hold securities. Ratings may be subject to revision or withdrawal at any time by the rating organization. The following table summarizes the Corporation's credit ratings as at March 8, 2010.

Fortis
Credit Ratings

Company	DBRS	S&P	Moody's
Fortis	BBB (high), stable (unsecured debt)	A-, stable (unsecured debt)	N/A
Terasen	BBB (high), stable (unsecured debt)	BBB+, stable (1) (unsecured debt)	Baa2, stable (unsecured debt)
TGI	A, stable (secured & unsecured debt)	A, stable (1) (unsecured debt)	A3, stable (unsecured debt)
TGVI	N/A	N/A	A3, stable (unsecured debt)
FortisAlberta	A (low), stable (senior unsecured debt)	A-, stable (senior unsecured debt)	Baa1, stable (senior unsecured debt)
FortisBC	BBB (high), stable (secured & unsecured debt)	N/A	Baa2, stable (unsecured debt)
Newfoundland Power	A, stable (first mortgage bonds)	N/A	A2, stable (first mortgage bonds)
Maritime Electric	N/A	A, stable (senior secured debt)	N/A
Caribbean Utilities	A (low), stable (senior unsecured debt)	A, negative (senior unsecured debt)	N/A

(1) Unsolicited

DBRS rates debt instruments by rating categories ranging from AAA to D, which represents the range from highest to lowest quality of such securities. DBRS states that: (i) its long-term debt ratings are meant to give an indication of the risk that the borrower will not fulfill its obligations in a timely manner with respect to both interest and principal commitments; (ii) its ratings do not take factors such as pricing or market risk into consideration and are expected to be used by purchasers as one part of their investment decision; and (iii) every rating is based on quantitative and qualitative considerations that are relevant for the borrowing entity. According to DBRS, a rating of A by DBRS is in the middle of three subcategories within the third highest of nine major categories. Such rating is assigned to debt instruments considered to be of satisfactory credit quality and for which protection of interest and principal is still substantial, but the degree of strength is less than with AA rated entities. Entities in the BBB category are considered to have long-term debt of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities. The assignment of a (high) or (low) modifier within each rating category indicates relative standing within such category.

S&P long-term debt ratings are on a ratings scale that ranges from AAA to C, which represents the range from highest to lowest quality of such securities. S&P uses '+' or '-' designations to indicate the relative standing of securities within a particular rating category. S&P states that its credit ratings are current opinions of the financial security characteristics with respect to the ability to pay under contracts in accordance with their terms. This opinion is not specific to any particular contract, nor does it address the suitability of a particular contract for a specific purpose or purchaser. An issuer rated A is regarded as having financial security characteristics to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than those in higher-rated categories.

Moody's long-term debt ratings are on a rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities. In addition, Moody's applies numerical modifiers 1, 2 and 3 in each generic rating classification from Aa to Caa to indicate relative standing within such classification. The modifier 1 indicates that the security ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates that the security ranks in the lower end of its generic rating category. Moody's states that its long-term debt ratings are opinions of relative risk of fixed-income obligations with an original maturity of one year or more and that such ratings reflect both the likelihood of default and any financial loss suffered in the event of default. According to Moody's, a rating of Baa is the fourth highest of nine major categories and such a debt rating is assigned to debt instruments considered to be of medium-grade quality. Debt instruments rated Baa are subject to moderate credit risk and may possess certain speculative characteristics. Debt instruments rated A are considered upper-medium grade and are subject to low credit risk.

9.0 MARKET FOR SECURITIES

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 are listed on the Toronto Stock Exchange under the symbols FTS, FTS.PR.C, FTS.PR.E, FTS.PR.F, FTS.PR.G and FTS.PR.H, respectively. The First Preference Shares, Series H were issued in January 2010.

The following table sets forth the reported high and low trading prices and trading volumes for the Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; and First Preference Shares, Series G on a monthly basis for the year ended December 31, 2009.

Fortis
2009 Trading Prices and Volumes

	Common Shares			First Preference Shares, Series C		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
Jan	25.06	22.89	7,809,701	26.65	25.16	97,287
Feb	24.60	22.33	14,130,845	26.55	25.15	50,592
Mar	24.24	21.52	14,643,369	25.99	24.50	81,017
Apr	23.20	21.55	11,180,355	26.65	25.26	79,564
May	24.31	22.15	11,200,604	26.95	25.52	38,926
Jun	26.25	23.67	10,446,255	27.49	25.58	42,894
Jul	26.19	24.00	9,178,843	27.18	25.70	211,455
Aug	25.99	24.61	8,110,618	27.75	26.60	44,986
Sep	25.39	24.62	8,323,744	27.00	26.20	301,981
Oct	26.24	24.61	8,776,294	26.60	26.35	71,673
Nov	27.13	25.10	8,018,968	26.60	36.20	34,639
Dec	29.24	26.19	9,343,236	26.50	26.30	35,380

	First Preference Shares, Series E			First Preference Shares, Series F		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
Jan	27.99	24.25	161,245	19.84	17.00	126,556
Feb	25.30	25.00	60,300	20.54	18.26	91,487
Mar	25.00	24.80	64,032	20.40	18.80	65,467
Apr	25.25	24.90	135,449	20.03	19.01	65,507
May	25.45	24.90	92,569	20.89	19.05	99,625
Jun	26.48	25.50	63,207	20.50	19.50	79,762
Jul	26.39	25.80	273,473	22.07	19.78	71,397
Aug	27.00	25.80	78,233	22.95	20.75	101,294
Sep	27.77	26.16	38,648	22.76	20.89	52,237
Oct	26.89	25.55	22,395	21.95	21.19	90,588
Nov	26.75	25.95	316,465	22.25	21.50	74,136
Dec	27.00	26.25	140,681	21.70	21.15	57,368

	First Preference Shares, Series G		
Month	**High ($)**	**Low ($)**	**Volume**
Jan	23.00	19.90	128,062
Feb	23.98	22.29	83,648
Mar	23.70	21.50	88,211
Apr	25.00	22.44	117,185
May	25.49	23.94	152,290
Jun	25.75	24.70	121,421
Jul	26.36	25.25	164,608
Aug	26.67	25.10	208,514
Sep	26.24	25.21	180,506
Oct	26.01	25.35	145,816
Nov	26.49	25.75	51,453
Dec	27.17	26.10	63,422

10.0 DIRECTORS AND OFFICERS

The Board adopted a director tenure policy in 1999 which is reviewed on a periodic basis and was most recently affirmed at a meeting of the Board held in September 2007. The tenure policy provides that Directors of the Corporation are to be elected for a term of one year and, except in exceptional circumstances determined by the Board, be eligible for re-election until the Annual Meeting of Shareholders next following the earlier of the date on which they achieve age 70 or the 10th anniversary of their initial election to the Board. The policy does not apply to Mr. Marshall whose service on the Board is related to his tenure as CEO. The following chart sets out the name and municipality of residence of each of the Directors of Fortis and indicates their principal occupations within five preceding years.

Fortis Directors	
Name	**Principal Occupations Within Five Preceding Years**
PETER E. CASE *(1)* Freelton, Ontario	Mr. Case, 55, a Corporate Director, retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. During his 17-year career as senior investment analyst with CIBC World Markets and BMO Nesbitt Burns and its predecessors, Mr. Case's coverage of Canadian and selected U.S. pipeline and energy utilities was consistently rated among the top rankings. He was awarded a Bachelor of Arts and a Master of Business Administration from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto. Mr. Case was first elected to the Board in May 2005. He was appointed Chair of the Board of FortisOntario in 2009. Mr. Case has been a Director of FortisOntario since March 2003 He does not serve as a director of any other reporting issuer.
FRANK J. CROTHERS Nassau, Bahamas	Mr. Crothers, 65, is Chairman and Chief Executive Officer of Island Corporate Holdings Limited, Nassau, Bahamas. Over the past 35 years, he has served on many public and private sector boards. For more than a decade he was on the Board of Harvard University Graduate School of Education and also 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 the Corporation in August 2006. He serves as the Vice Chair of the Board of Caribbean Utilities and serves on the Board of Belize Electricity. Mr. Crothers was first elected to the Fortis Board in May 2007. He is also a director of reporting issuers Templeton Mutual Funds, Fidelity Merchant Bank & Trust (Cayman) Limited and Talon Metals Corp.
IDA J. GOODREAU *(3)* Vancouver, British Columbia	Ms. Goodreau, 58, is the past President and Chief Executive Officer of LifeLabs. Prior to joining Lifelabs in March 2009, she was President and Chief Executive Officer of Vancouver Coastal Health Authority since 2002. Ms. Goodreau has held senior leadership roles in several Canadian and international pulp and paper and natural gas companies prior to entering the health care field. She was awarded a Master of Business Administration and a Bachelor of Commerce, Honors, degree from the University of Windsor and a Bachelor of Arts, (English and Economics) from the University of Western Ontario. Ms. Goodreau was first elected to the Board in May 2009. She has served on numerous private and public sector boards and is a director of Terasen.
DOUGLAS J. HAUGHEY *(1)* Calgary, Alberta	Mr. Haughey, 53, is President and Chief Executive Officer of WindShift Capital Corp. focused on energy infrastructure investment opportunities in North America. Prior to forming Windshift Capital Corp. in 2008, he held several executive roles with Spectra Energy and predecessor companies. He had overall responsibility for its western Canadian natural gas midstream business, was President and Chief Executive Officer of Spectra Energy Income Fund and also led Spectra's strategic development and mergers and acquisitions teams based in Houston, Texas. He graduated from the University of Regina with a Bachelor of Administration and from the University of Calgary with a Master of Business Administration. Mr. Haughey also holds an ICD.D designation from the Institute of Corporate Directors. He was first elected to the Board in May 2009. Mr. Haughey also serves as a director of Pembina Pipeline Income Fund.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
GEOFFREY F. HYLAND (1)(2)(3) Caledon, Ontario	Mr. Hyland, 65, a Corporate Director, retired as President and Chief Executive Officer of ShawCor Ltd. in June 2005 after 37 years of service. He graduated from McGill University with a Bachelor of Engineering (Chemical) and York University with a Master of Business Administration. Mr. Hyland was first elected to the Board in May 2001 and was appointed Chair of the Board in May 2008. He is a director of FortisOntario. Mr. Hyland continues to serve on the board of ShawCor Ltd. and is a director of SCITI Total Return Trust and Exco Technologies Limited.
H. STANLEY MARSHALL Paradise, Newfoundland and Labrador	Mr. Marshall, 59, is President and Chief Executive Officer of the Corporation. He joined Newfoundland Power in 1979 and was appointed President and Chief Executive Officer of Fortis in 1996. Mr. Marshall graduated from the University of Waterloo with a Bachelor of Applied Science (Chem. Eng.) and Dalhousie University with a Bachelor of Laws. He is a member of the Law Society of Newfoundland and Labrador and a Registered Professional Engineer in the Province of Newfoundland and Labrador. Mr. Marshall was first elected to the Board in October 1995. He serves on the boards of all Fortis utilities in western Canada and the Caribbean (including Caribbean Utilities) and the Board of Fortis Properties. He is also a director of Toromont Industries Ltd.
JOHN S. McCALLUM (1)(2) Winnipeg, Manitoba	Mr. McCallum, 66, has been a Professor of Finance at the University of Manitoba since July 1973. He served as Chairman of Manitoba Hydro from 1991 to 2000 and as Policy Advisor to the Federal Minister of Finance from 1984 to 1991. Mr. McCallum graduated from the University of Montreal with a Bachelor of Arts (Economics) and a Bachelor of Science (Mathematics). He was awarded a Master of Business Administration from Queen's University and a PhD in Finance from the University of Toronto. Mr. McCallum was first elected to the Board in July 2001 and was appointed Chair of the Governance and Nominating Committee of the Corporation in May 2005. He is a director of FortisBC and FortisAlberta and chairs the Audit, Risk and Environment Committees of both companies. Mr. McCallum also serves as a director of IGM Financial Inc., Toromont Industries Ltd. and Wawanesa.
HARRY McWATTERS (2) Summerland, British Columbia	Mr. McWatters, 64, is the founder and past President of Sumac Ridge Estate Wine Group, a leader in the British Columbia wine industry. He is President of Vintage Consulting Group Inc., Harry McWatters Inc., Okanagan Wine Academy and Black Sage Vineyards Ltd., all of which are engaged in various aspects of the British Columbia wine industry. Mr. McWatters was first elected to the Board in May 2007. He was elected to the Board of FortisBC Inc. in September 2005 and appointed as Chair of that Company's Board in 2006. Mr. McWatters became a director of Terasen in November 2007 and does not serve as a director of any other reporting issuer.
RONALD D. MUNKLEY (2) Mississauga, Ontario	Mr. Munkley, 63, a Corporate Director, 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 Chief Executive Officer. Mr. Munkley led Enbridge Consumers Gas through deregulation and restructuring in the 1990s. He graduated from Queen's University with a Bachelor of Science, Honors (Engineering). Mr. Munkley is a professional engineer and has completed the Executive and Senior Executive Programs of the University of Western Ontario and the Partners, Directors and Senior Officers Certificate of the Canadian Securities Institute. He was first elected to the Board in May 2009.
DAVID G. NORRIS (1)(3) St. John's, Newfoundland and Labrador	Mr. Norris, 62, a Corporate Director, 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 graduated with a Bachelor of Commerce from Memorial University of Newfoundland and a Master of Business Administration from McMaster University. He was first elected to the Board in May 2005 and, in May 2006, Mr. Norris was appointed Chair of the Audit Committee of the Board. He has been a director of Newfoundland Power since 2003 and was appointed Chair of that Company's Board in April 2006. Mr. Norris was appointed to the Board of Fortis Properties in 2006. He does not serve as a director of any other reporting issuer.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
MICHAEL A. PAVEY (3) Moncton, New Brunswick	Mr. Pavey, 62, a Corporate Director, retired as Executive Vice-President and Chief Financial Officer of Major Drilling Group International Inc. in September 2006. Prior to joining Major Drilling Group International Inc. in 1999, he held senior executive positions with a major integrated electric utility in western Canada. Mr. Pavey graduated from the University of Waterloo with a Bachelor of Applied Science (Mechanical Engineering) and from McGill University with a Master of Business Administration. He retired from the Board of Maritime Electric in February 2007 after a six-year term, which included three years' service as Chair of that Company's Audit and Environment Committee. Mr. Pavey was first elected to the Board in May 2004. Mr. Pavey does not serve as a director of any other reporting issuer.
ROY P. RIDEOUT (2)(3) Halifax, Nova Scotia	Mr. Rideout, 62, a Corporate Director, retired as Chairman and Chief Executive Officer of Clarke Inc. in October 2002. Prior to 1998, he served as President of Newfoundland Capital Corporation Limited and held senior executive positions in the Canadian airline industry. Mr. Rideout graduated with a Bachelor of Commerce from Memorial University of Newfoundland and obtained designation as a Chartered Accountant. Mr. Rideout was first elected to the Board in March 2001. He is the Chair of the Human Resources Committee of the Board and has held that position since May 2003. Mr. Rideout also serves as a director of NAV CANADA.

(1) *Serves on the Audit Committee*
(2) *Serves on the Governance and Nominating Committee*
(3) *Serves on the Human Resources Committee*

The following table sets out the name and municipality of residence of each of the officers of Fortis and indicates the office held.

Fortis Officers	
Name and Municipality of Residence	**Office Held**
H. Stanley Marshall Paradise, Newfoundland and Labrador	President and Chief Executive Officer (1)
Barry V. Perry Mount Pearl, Newfoundland and Labrador	Vice President, Finance and Chief Financial Officer (2)
Ronald W. McCabe St. John's, Newfoundland and Labrador	Vice President, General Counsel and Corporate Secretary (3)
Donna G. Hynes St. John's, Newfoundland and Labrador	Assistant Secretary (4)

(1) *Mr. Marshall was appointed President and Chief Operating Officer, effective October 1, 1995. Effective May 1, 1996, Mr. Marshall became Chief Executive Officer.*
(2) *Mr. Perry was appointed Vice President, Finance and Chief Financial Officer, effective January 1, 2004. Prior to that time, Mr. Perry was Vice President, Finance and Chief Financial Officer of Newfoundland Power.*
(3) *Mr. McCabe was appointed General Counsel and Corporate Secretary, effective January 1, 1997. Effective May 6, 2008, Mr. McCabe became Vice President, General Counsel and Corporate Secretary.*
(4) *Ms. Hynes was appointed Assistant Secretary, effective December 8, 1999. She joined Fortis as Manager, Investor and Public Relations in October 1999 and, prior to that time, was employed by Newfoundland Power.*

As at December 31, 2009, the directors and officers of Fortis, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 684,201 Common Shares, representing 0.4 per cent of the issued and outstanding Common Shares of Fortis. The Common Shares are the only voting securities of the Corporation.

11.0 AUDIT COMMITTEE

11.1 Education and Experience

The education and experience of each Audit Committee Member that is relevant to such Member's responsibilities as a Member of the Audit Committee are set out below. As at December 31, 2009, the Audit Committee was composed of the following persons.

Fortis Audit Committee	
Name	**Relevant Education and Experience**
PETER E. CASE Freelton, Ontario	Mr. Case retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. He was awarded a Bachelor of Arts and a Master of Business Administration from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto.
DOUGLAS J. HAUGHEY Calgary, Alberta	Mr. Haughey is President and Chief Executive Officer of WindShift Capital Corp. He graduated from the University of Regina with a Bachelor of Administration and from the University of Calgary with a Master of Business Administration. Mr. Haughey also holds an ICD.D designation from the Institute of Corporate Directors.
GEOFFREY F. HYLAND Caledon, Ontario	Mr. Hyland retired as President and Chief Executive Officer of ShawCor Ltd. in June 2005 after 37 years of service. He graduated from McGill University with a Bachelor of Engineering (Chemical) and from York University with a Master of Business Administration.
JOHN S. McCALLUM Winnipeg, Manitoba	Mr. McCallum is a Professor of Finance at the University of Manitoba. He graduated from the University of Montreal with a Bachelor of Arts (Economics) and a Bachelor of Science (Mathematics). Mr. McCallum was awarded a Master of Business Administration from Queen's University and a PhD in Finance from the University of Toronto.
DAVID G. NORRIS *(Chair)* St. John's, Newfoundland and Labrador	Mr. Norris graduated with a Bachelor of Commerce from Memorial University of Newfoundland and a Master of Business Administration from McMaster University. 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.

The Board has determined that each of the Audit Committee Members is independent and financially literate. Independent means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment as more particularly described in Multilateral Instrument 52-110 - Audit Committees. Financially literate means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements.

11.2 Audit Committee Mandate

The text of the Corporation's Audit Committee Mandate is detailed below.

Objective

The Audit Committee shall provide assistance to the Board by overseeing the external audit of the Corporation's annual financial statements and the accounting and financial reporting and disclosure processes and policies of the Corporation.

Definitions

In this mandate:

"AIF" means the Annual Information Form filed by the Corporation;

"Committee" means the Audit Committee appointed by the Board pursuant to this mandate;

"Board" means the board of directors of the Corporation;

"CICA" means the Canadian Institute of Chartered Accountants or any successor body;

"Corporation" means Fortis Inc.;

"**Director"** means a member of the Board;

"Financially Literate" means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be present in the Corporation's financial statements;

"External Auditor" means the firm of chartered accountants, registered with the Canadian Public Accountability Board or its successor, and appointed by the shareholders of the Corporation to act as External Auditor of the Corporation;

"Independent" means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment as more particularly described in Multilateral Instrument 52-110;

"Internal Auditor" means the person employed or engaged by the Corporation to perform the internal audit function of the Corporation;

"Management" means the senior officers of the Corporation;

"MD&A" means the Corporation's management discussion and analysis prepared in accordance with National Instrument 51-102F1 in respect of the Corporation's annual and interim financial statements; and

"Member" means a Director appointed to the Committee.

Composition and Meetings

1. The Committee shall be appointed annually by the Board and shall be comprised of three (3) or more Directors; each of whom is Independent and Financially Literate and none of whom is a member of Management or an employee of the Corporation or of any affiliate of the Corporation.

2. The Board shall appoint a Chair of the Committee on the recommendation of the Corporation's Governance and Nominating Committee, or such other committee as the Board may authorize.

3. The Committee shall meet at least four (4) times each year and shall meet at such other times during the year as it deems appropriate. Meetings of the Committee shall be held at the call of: (i) the Chair of the Committee, or (ii) any two (2) Members, or (iii) the External Auditor.

4. The President and Chief Executive Officer, the Vice President, Finance and Chief Financial Officer, the External Auditor and the Internal Auditor shall receive notice of, and (unless otherwise determined by the Chair of the Committee) shall attend all meetings of the Committee.

5. A quorum at any meeting of the Committee shall be three (3) Members.

6. The Chair of the Committee shall act as chair of all meetings of the Committee at which the Chair is present. In the absence of the Chair from any meeting of the Committee, the Members present at the meeting shall appoint one of their Members to act as Chair of the meeting.

7. Unless otherwise determined by the Chair of the Committee, the Secretary of the Corporation shall act as secretary of all meetings of the Committee.

Oversight of the External Audit and the Accounting and Financial Reporting and Disclosure Processes and Policies

The primary purpose of the Committee is oversight of the Corporation's external audit and the accounting and financial reporting and disclosure processes and policies on behalf of the Board. Management of the Corporation is responsible for maintaining appropriate accounting and financial reporting principles, policies, internal controls and procedures that provide for compliance with accounting standards and applicable laws and regulations. Management is responsible for the preparation and integrity of the financial statements of the Corporation.

1. Oversight of the External Audit

   The oversight of the external audit pertains to the audit of the Corporation's annual financial statements.

   1.1. The Committee is responsible for the evaluation and recommendation of the External Auditor to be proposed by the Board for appointment by the shareholders.

   1.2. In advance of each audit, the Committee shall review the External Auditor's audit plan including the general approach, scope and areas subject to risk of material misstatement.

   1.3. The Committee is responsible for approving the terms of engagement and fees of the External Auditor.

   1.4. The Committee shall review and discuss the Corporation's annual audited financial statements, together with the External Auditor's report thereon, and MD&A with Management and the External Auditor to gain reasonable assurance as to the accuracy, consistency and completeness thereof. The Committee shall meet privately with the External

Auditor. The Committee shall oversee the work of the External Auditor and resolve any disagreements between Management and the External Auditor.

1.5. The Committee shall use reasonable efforts, including discussion with the External Auditor, to satisfy itself as to the External Auditor's independence as defined in the CICA Assurance Handbook Section 5751.

2. Oversight of the Accounting and Financial Reporting and Disclosure Processes

2.1. The Committee shall recommend the annual audited financial statements together with the MD&A for approval by the Board.

2.2. The Committee shall review the interim unaudited financial statements with the External Auditor and Management, together with the External Auditor's review engagement report thereon.

2.3. The Committee shall review and approve publication of the interim unaudited financial statements, together with the interim MD&A and earnings media release on behalf of the Board.

2.4. The Committee shall review and recommend approval by the Board of the Corporation's AIF, Management Information Circular, any prospectus and other financial information or disclosure documents to be issued by the Corporation prior to their public release.

2.5. The Committee shall use reasonable efforts to satisfy itself as to the integrity of the Corporation's financial information systems, internal control over financial reporting and the competence of the Corporation's accounting personnel and senior financial management responsible for accounting and financial reporting.

2.6. The Committee shall be responsible for the oversight of the Internal Auditor.

3. Oversight of the Audit Committee Mandate and Policies

On a periodic basis, the Committee shall review and report to the Board on the Audit Committee Mandate as well as on the following policies:

3.1. Reporting Allegations of Suspected Improper Conduct and Wrongdoing Policy;

3.2. Derivative Financial Instruments and Hedging Policy;

3.3. Pre-Approval of Audit and Non-Audit Services Policy;

3.4. Hiring of Employees from Independent Auditing Firms Policy;

3.5. The Internal Audit Role and Function Policy; and

3.6. any other policies that may be established, from time to time, relating to accounting and financial reporting and disclosure processes; oversight of the external audit of the Corporation's financial statement; and oversight of the internal audit function.

Reporting

The Chair of the Committee, or another designated Member, shall report to the Board at each regular meeting on those matters which were dealt with by the Committee since the last regular meeting of the Board.

Other

1. The Committee shall perform such other functions as may, from time to time, be assigned to the Committee by the Board.

2. The Committee may approve, in circumstances that it considers appropriate, the engagement by the Committee or any Director of outside advisors or persons having special expertise at the expense of the Corporation.

11.3 Pre-Approval Policies and Procedures

The Audit Committee has established a policy which requires pre-approval of all audit and non-audit services provided to the Corporation and its subsidiaries by the Corporation's External Auditor. The Pre-Approval of Audit and Non-Audit Services Policy describes the services which may be contracted from the External Auditor and the limitations and authorization procedures related thereto. This policy defines services such as bookkeeping, valuations, internal audit and management functions which may not be contracted from the External Auditor and establishes an annual limit for permissible non-audit services not greater than the total fee for audit services. Audit Committee pre-approval is required for all audit and non-audit services.

11.4 External Auditor Service Fees

Fees incurred by the Corporation for work performed by Ernst & Young LLP, the Corporation's External Auditors, during each of the last two fiscal years for audit, audit-related, tax and non-audit services were as follows:

Fortis External Auditor Service Fees *($ thousands)*		
Ernst & Young LLP	**2009**	2008
Audit Fees	**$ 2,279.8**	$ 2,467.3
Audit-Related Fees	**855.2**	853.0
Tax Fees	**353.5**	125.8
Total	**$ 3,488.5**	$ 3,446.1

The decrease in audit fees in 2009, as compared to 2008, primarily related to the requirement for additional year-end audit work in 2008 associated with the change in Caribbean Utilities fiscal year end from April 30 to December 31. The increase in tax fees in 2009, as compared to 2008, was due to tax work associated with the corporate reorganization of FortisUS Energy and work performed in relation to the adoption of amended CICA Handbook Section 3465, *Income Taxes,* by the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power in 2009.

12.0 TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares and First Preference Shares of Fortis is Computershare Trust Company of Canada in Halifax, Montréal and Toronto.

Computershare Trust Company of Canada
9th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
E: service@computershare.com
W: www.computershare.com/fortisinc

13.0 AUDITORS

The auditors of the Corporation are Ernst & Young LLP, Chartered Accountants, The Fortis Building, 7th Floor, 139 Water Street, St. John's, NL, A1C 1B2. The financial statements of the Corporation for the fiscal year ended December 31, 2009 have been audited by Ernst & Young LLP. Ernst & Young LLP report that they are independent of the Corporation in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Newfoundland.

14.0 ADDITIONAL INFORMATION

Reference is made to the MD&A on pages 20 through 81 of the 2009 Fortis Inc. Annual Report to Shareholders, which pages are incorporated herein by reference. Additional information relating to the Corporation can be found on SEDAR at www.sedar.com.

Further additional information, including officers' and directors' remuneration and indebtedness, principal holders of the securities of Fortis, options to purchase securities and interests of insiders in material transactions, where applicable, is contained in the Management Information Circular of Fortis dated March 22, 2010 for the May 4, 2010 Annual Meeting of Shareholders. Additional financial information is also provided in the comparative consolidated financial statements and MD&A of Fortis for the year ended December 31, 2009.

Requests for additional copies of the above-mentioned documents, as well as the 2009 Annual Information Form, should be directed to the Corporate Secretary, Fortis, P.O. Box 8837, St. John's, NL, A1B 3T2 (telephone: 709.737.2800). In addition, such documentation and additional information relating to the Corporation is contained on the Corporation's website at www.fortisinc.com.