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Management's Discussion and Analysis (MD&A) dated February 22, 2010 should be read in conjunction with the accompanying audited Consolidated Financial Statements of TransCanada Corporation (TransCanada or the Company) and the notes thereto for the year ended December 31, 2009 which are prepared in accordance with Canadian generally accepted accounting principles (GAAP). This MD&A covers TransCanada's financial position and operations as at and for the year ended December 31, 2009. "TransCanada" or "the Company" includes TransCanada Corporation and its subsidiaries unless otherwise indicated. Amounts are stated in Canadian dollars unless otherwise indicated. Abbreviations and acronyms not defined in this MD&A are defined in the Glossary of Terms in the Company's 2009 Annual Report.

TRANSCANADA OVERVIEW

At December 31, 2009, TransCanada had completed approximately $10 billion of its $22 billion capital program. Upon completion of this program, these assets are expected to generate additional annual earnings before interest, taxes, depreciation and amortization (EBITDA) of approximately $2.5 billion. The Company expects to complete most of the projects in its capital growth program by the end of 2013. Over the longer term, TransCanada intends to continue to develop its substantial asset portfolio and pursue other large-scale pipeline and energy infrastructure projects. TransCanada is committed to maintaining the financial strength required to invest in the development of North American energy infrastructure and respond to shifting energy supply-demand dynamics.

TransCanada's 2009 Key Accomplishments

- Acquired ConocoPhillips' remaining interest in Keystone, increasing TransCanada's ownership to 100 per cent;
- completed the first phase of construction of Keystone to Wood River and Patoka, Illinois;
- entered into an arrangement with ExxonMobil to jointly develop the Alaska pipeline and, in January 2010, filed a plan to obtain approval to conduct the first natural gas pipeline open season to develop Alaska's vast natural gas resources;
- Portlands Energy and the first phase of Kibby Wind were placed into service; and
- issued approximately $6 billion of debt and equity during a challenging North American economic environment.

Pipelines Assets

The TransCanada pipeline network, including assets under construction and development, consists of more than 60,000 kilometres (km) (37,000 miles) of wholly owned and 8,800 km (5,468 miles) of partially owned natural gas pipelines and transports 20 per cent of the natural gas consumed in North America. TransCanada's natural gas pipelines link gas supplies from Western Canada, the United States (U.S.) mid-continent and Gulf of Mexico to premium North American markets. These assets are well positioned to connect emerging natural gas supplies, including northern gas, northeastern British Columbia (B.C.) and U.S. shale gas, Rocky Mountain gas and offshore liquefied natural gas (LNG) imports, to growing markets.

TransCanada's Alberta System gathered 66 per cent of the natural gas produced in Western Canada or 14 per cent of total North American production in 2009. TransCanada transports natural gas from the Western Canada Sedimentary Basin (WCSB) to Eastern Canada and the U.S. West, Midwest, and Northeast through three wholly owned pipeline systems: the Canadian Mainline, GTN and Foothills. TransCanada also transports natural gas from the WCSB to Eastern Canada and to the U.S. West, Midwest and Northeast through six partially owned natural gas pipeline systems: Great Lakes, Iroquois, Portland, TQM, Northern Border and Tuscarora. Certain of these pipeline systems are held through the Company's 38.2 per cent interest in TC PipeLines, LP (PipeLines LP).

ANR transports natural gas from producing fields located primarily in Texas, Oklahoma, the Gulf of Mexico and Louisiana to markets located in Wisconsin, Michigan, Illinois, Ohio and Indiana. It also connects with numerous other natural gas pipelines, providing customers with access to diverse sources of North American supply, including Western Canada and the Rocky Mountain region, and to a variety of end-user markets in the midwestern and northeastern U.S. ANR owns and operates 250 billion cubic feet (Bcf) of regulated natural gas storage capacity in Michigan. TransCanada also serves natural gas markets in Mexico through its Tamazunchale and North Baja pipelines, and will expand service to markets in Mexico with the Guadalajara pipeline which is under construction.

In addition, TransCanada is constructing the approximately 6,200 km (3,853 miles) Keystone crude oil pipeline. Keystone is expected to transport 1.1 million barrels per day (Bbl/d) of crude oil from Hardisty, Alberta to U.S. Midwest markets at Wood River and Patoka, Illinois, and to Cushing, Oklahoma, and to U.S. Gulf Coast markets. The pipeline will provide a low-cost shipping option to customers and is supported by long-term contracts with creditworthy counterparties. The first phase of Keystone, which is to Wood River and Patoka, is expected to commence delivery of crude oil in mid-2010 with the remaining phases expected to commence service in first quarter 2011 and first quarter 2013. In the medium to long term, opportunities for further additions to Keystone would expand the pipeline's transport capacity to 1.5 million Bbl/d from 1.1 million Bbl/d.

Energy Assets

TransCanada's Energy business has grown to more than 11,700 megawatts (MW) in 2009 from 754 MW in 1999, including assets under construction and development. The Company's diverse power generation portfolio of primarily low-cost, base load and long-term contracted facilities comprises a total of 20 plants in Alberta, Arizona, Eastern Canada, New England and New York City.

TransCanada's Western Power business comprises approximately 2,600 MW of power supply in Alberta and the western U.S. The Western Power portfolio in Alberta consists of three long-term power purchase arrangements (PPA): the Sheerness and Sundance A and B coal-fired plants, and five natural gas-fired cogeneration facilities consisting of MacKay River, Carseland, Bear Creek, Redwater and Cancarb. The Sundance A PPA expires in 2017 and the Sundance B and Sheerness PPAs expire in 2020. The other power facility in the Western Power portfolio is Coolidge, a natural gas-fired peaking facility under construction in Arizona whose output will be sold under a 20 year PPA. Coolidge is expected to be in service in second quarter 2011. Western Power's marketing business serves an integral function by purchasing and reselling electricity and natural gas to maximize the return from the Western Power assets.

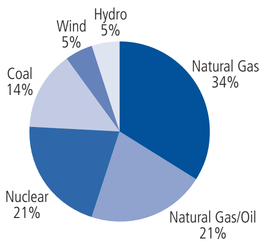
The Eastern Power business is comprised of approximately 2,900 MW of power generation capacity, including facilities under construction. Eastern Power's operating assets consist of Bécancour, three of five Cartier Wind farms, Portlands Energy and Grandview. Power from Bécancour and Cartier Wind is sold to Hydro-Québec through 20 year power purchase contracts. Output from the Portlands Energy and Grandview facilities is sold through 20 year contracts with the Ontario Power Authority (OPA) and Irving Oil Limited (Irving), respectively. Halton Hills and the remaining two Cartier Wind farms which are under construction are expected to be in service in 2010, 2011 and 2012, respectively. Oakville, which is currently under development, is expected to be in service in first quarter 2014. Once operational, Oakville and Halton Hills will sell power to the OPA through 20 year contracts and the remaining two Cartier Wind farms will sell power to Hydro-Québec through 20 year contracts.

TransCanada has a 48.8 per cent interest in Bruce A and a 31.6 per cent interest in Bruce B, which together comprise the Bruce Power nuclear generating facility. Bruce A has four 750 MW reactors, two of which are being refurbished, and Bruce B has four operational reactors with a combined capacity of 3,200 MW. Through a contract with the OPA, all of the output from Bruce A is effectively sold at a fixed price and the output from Bruce B is subject to a floor price.

TransCanada's U.S. Power assets have approximately 3,800 MW of power generation capacity, including facilities under construction. The operating assets in the U.S. Power portfolio consist of Ravenswood, TC Hydro, OSP and phase one of Kibby Wind. Phase two of Kibby Wind is under construction and is expected to be placed into service in third quarter 2010. U.S. Power sells power to wholesale, commercial and industrial customers through TransCanada Power Marketing Ltd. (TCPM), a wholly owned subsidiary of TransCanada.

The accompanying graph illustrates each fuel source as a percentage of the Company's overall Energy portfolio:

Power by Fuel Source



TransCanada has developed a significant non-regulated natural gas storage business in Alberta where the Company owns or has rights to 129 Bcf or approximately one-third of natural gas storage capacity in the province.

TRANSCANADA'S STRATEGY

TransCanada's vision is to be the leading energy infrastructure company in North America, focusing on pipelines and power generation opportunities in regions where it has or can develop a significant competitive advantage. TransCanada's key strategies continue to evolve with the Company's growth and development and its changing business environment. TransCanada's corporate strategy integrates five fundamental value-creating activities:

1. Maximize the full-life value of TransCanada's infrastructure assets and commercial positions
2. Cultivate a focused portfolio of high quality development options
3. Commercially develop and physically execute new asset investment programs
4. Maximize TransCanada's competitive strengths
5. Maximize TransCanada's reputation and standing in financial markets

Maximize the full-life value of TransCanada's infrastructure assets and commercial positions

TransCanada relies on a low-risk business model to maximize the full-life value of its existing assets and commercial positions. In Pipelines, large scale natural gas and crude oil pipelines connect long life supply basins with stable and growing markets, generating predictable, sustainable cash flows and earnings of a long term nature. In Energy, highly efficient large scale power generation facilities supply power markets through long term power purchase and sale agreements and low-volatility shorter term commercial arrangements. TransCanada's growing investments in natural gas, nuclear, wind and hydro generating facilities demonstrate the Company's commitment to sustainable, clean energy. Long-life infrastructure assets and long term commercial arrangements will continue as cornerstones of TransCanada's business model.

Cultivate a focused portfolio of high quality development options

The Company's core regions within North America are the primary focus of growth initiatives in Pipelines and Energy. TransCanada will continue to pursue opportunities to connect long-life shale and conventional gas resources in western Canada, northern Canada, Alaska, U.S. Rockies, U.S. midcontinent and Gulf Coast supply regions. TransCanada will continue to pursue opportunities to connect growing crude oil volumes from the Alberta oilsands to preferred North American markets. The Company will continue to assess pipeline acquisition opportunities that complement its existing pipeline networks and provide access to new supply and market regions. In Energy, the Company will continue to focus on low-cost, long-life base load power generating and natural gas storage assets supported by firm, long-term contracts with reputable counterparties. Selected opportunities will move forward to full development and construction when market conditions are appropriate and project risks are manageable.

Commercially develop and physically execute new asset investment programs

TransCanada expects to substantially complete construction of assets under its current $22 billion capital program by the end of 2013. The Company is focused on completing its capital projects on time and on budget, enabling it to meet commitments to customers and to deliver attractive, long-term returns to shareholders. The current capital program is characterized by highly contracted, long-term revenue streams with limited exposure to commodity prices.

Capital cost risks are managed by TransCanada's strong and experienced project management teams and industry-leading project management practices.

Maximize TransCanada's competitive strengths

TransCanada continues to build competitive strength in areas that directly drive long-term shareholder value. The Company relies on its scale, presence, operating capabilities, strong leadership and capable teams to compete effectively and deliver outstanding value to its customers. A disciplined approach to capital investment combined with a low cost of capital allows the Company to create significant shareholder value from large capital projects. TransCanada recognizes that constructive relationships with key customers and stakeholders are critically important in the long-term energy infrastructure business. The Company continues to identify and build on all aspects of competitive strength.

Maximize TransCanada's reputation and standing in financial markets

TransCanada values its reputation for consistent financial performance and long term financial stability. The Company clearly communicates its financial performance to equity and debt investors, providing insight into both value upside and business risks. The Company works to sustain the trust and support of its long-term investors and to attract new investors who see long term value in a disciplined approach to the energy infrastructure business.

CONSOLIDATED FINANCIAL REVIEW

SELECTED THREE YEAR CONSOLIDATED FINANCIAL DATA
(millions of dollars, except per share amounts)

	2009	2008	2007
Income Statement			
Revenues	**8,966**	8,619	8,828
Comparable EBITDA[(1)]	**4,107**	4,125	3,919
Comparable EBIT[(1)]	**2,730**	2,878	2,682
EBIT[(1)]	**2,760**	3,133	2,708
Net income	**1,380**	1,440	1,223
Preferred share dividends	**6**	–	–
Net income applicable to common shares	**1,374**	1,440	1,223
Comparable earnings[(1)]	**1,325**	1,279	1,100
Per Common Share Data			
Net income per share			
Basic	**$2.11**	$2.53	$2.31
Diluted	**$2.11**	$2.52	$2.30
Comparable earnings per share[(1)]	**$2.03**	$2.25	$2.08
Dividends declared per share	**$1.52**	$1.44	$1.36
Cash Flows			
Funds generated from operations[(1)]	**3,080**	3,021	2,621
(Increase)/decrease in operating working capital	**(90)**	135	63
Net cash provided by operations	**2,990**	3,156	2,684
Capital expenditures	**5,417**	3,134	1,651
Acquisitions, net of cash acquired	**902**	3,229	4,223
Balance Sheet			
Total assets	**43,841**	39,414	30,330
Total long-term liabilities	**21,959**	20,158	16,508

(1) Refer to the Non-GAAP Measures section of this MD&A for further discussion of comparable EBITDA, comparable EBIT, EBIT, comparable earnings, comparable earnings per share and funds generated from operations.

HIGHLIGHTS

Earnings

- Net income was $1,380 million and net income applicable to common shares was $1,374 million or $2.11 per share in 2009 compared to $1,440 million or $2.53 per share in 2008.
- TransCanada's comparable earnings of $1,325 million in 2009 excluded an after tax dilution gain of $18 million resulting from the Company's reduced interest in PipeLines LP and $30 million of favourable income tax adjustments. Comparable earnings of $1,279 million in 2008 excluded $152 million of after tax gains from bankruptcy settlements with certain subsidiaries of Calpine Corporation (Calpine), proceeds of $10 million after tax from a lawsuit settlement, a $27 million after tax writedown of costs for the Broadwater LNG project and $26 million of favourable income tax adjustments.

Cash Flow

- Funds generated from operations were $3.1 billion in 2009, an increase of $0.1 billion from 2008.
- TransCanada invested $6.3 billion in its Pipelines and Energy capital projects in 2009, including the following:
  - Capital expenditures of $3.9 billion for Pipelines projects, including construction of Keystone and the Bison pipeline project, and expansion of the Alberta System;
  - capital expenditures of $1.5 billion for Energy projects, including the refurbishment and restart of Bruce A Units 1 and 2, and construction of Kibby Wind, Halton Hills, and Coolidge; and
  - acquisition of ConocoPhillips' remaining interest in Keystone for $0.9 billion.
- In 2009, TransCanada issued approximately $3.3 billion of long-term debt, $2.1 billion of common shares and $0.5 billion of preferred shares, comprised primarily of the following:
  - In September 2009, the issuance of 22 million preferred shares at $25.00 each, resulting in gross proceeds of $0.6 billion;
  - in June 2009, the issuance of 58.4 million common shares at $31.50 each, resulting in gross proceeds of $1.8 billion;
  - in February 2009, the issuance of $0.7 billion of Medium-Term Notes;
  - in January 2009, the issuance of US$2.0 billion of Senior Unsecured Notes; and
  - in accordance with its Dividend Reinvestment and Share Purchase Plan (DRP), the issuance of eight million common shares from treasury in lieu of making cash dividend payments totalling $0.3 billion.
- In December 2009, TransCanada established a new US$1.0 billion committed bank facility.
- In November 2009, PipeLines LP issued five million common units at US$38.00 per unit, resulting in gross proceeds of US$0.2 billion.

Balance Sheet

- Total assets increased by $4.4 billion to $43.8 billion in 2009 compared to 2008, primarily due to investments in Pipelines and Energy capital projects.
- TransCanada's shareholders' equity increased by $2.9 billion to $15.8 billion in 2009 compared to 2008.

Dividends

- On February 22, 2010, the Board of Directors of TransCanada increased the quarterly dividend on the Company's outstanding common shares for the quarter ending March 31, 2010 by five per cent to $0.40 per share from $0.38 per share. This was the tenth consecutive year in which the common share dividend was increased. In addition, a quarterly dividend of $0.2875 per preferred share was declared for the quarter ending March 31, 2010.

Refer to the Consolidated Financial Review, Results of Operations and Liquidity and Capital Resources sections of this MD&A for further discussion of these highlights.

SEGMENT RESULTS

Effective January 1, 2009, TransCanada revised the information presented in the tables of this MD&A to better reflect the operating and financing structure of the Company. The Pipelines and Energy results summaries are presented geographically by separating the Canadian and U.S. portions of each segment. The Company believes this new format more clearly describes the financial performance of its businesses. The new format presents EBITDA and earnings before interest and taxes (EBIT), which the Company believes provide greater transparency and more useful information with respect to the performance of its individual assets. Segmented information has been retroactively reclassified to reflect these changes. These changes had no impact on reported consolidated net income.

Reconciliation of Comparable EBITDA, Comparable EBIT, EBIT and Comparable Earnings to Net Income Applicable to Common Shares

Year ended December 31, 2009 *(millions of dollars except per share amounts)*	Pipelines	Energy	Corporate	Total
Comparable EBITDA[1]	3,093	1,131	(117)	4,107
Depreciation and amortization	(1,030)	(347)	–	(1,377)
Comparable EBIT[1]	2,063	784	(117)	2,730
Specific items:				
Dilution gain from reduced interest in PipeLines LP	29	–	–	29
Fair value adjustments of natural gas inventory in storage and forward contracts	–	1	–	1
EBIT[1]	2,092	785	(117)	2,760
Interest expense				(954)
Interest expense of joint ventures				(64)
Interest income and other				121
Income taxes				(387)
Non-controlling interests				(96)
Net Income				1,380
Preferred share dividends				(6)
Net Income Applicable to Common Shares				1,374
Specific items (net of tax where applicable):				
Dilution gain from reduced interest in PipeLines LP				(18)
Fair value adjustments of natural gas inventory in storage and forward contracts				(1)
Income tax adjustments				(30)
Comparable Earnings[1]				1,325
Net Income per Share – Basic				$2.11
Comparable Earnings per Share[1][2]				$2.03

Year ended December 31, 2008 *(millions of dollars except per share amounts)*	Pipelines	Energy	Corporate	Total
Comparable EBITDA[1]	3,019	1,210	(104)	4,125
Depreciation and amortization	(989)	(258)	–	(1,247)
Comparable EBIT[1]	2,030	952	(104)	2,878
Specific items:				
Calpine bankruptcy settlements	279	–	–	279
GTN lawsuit settlement	17	–	–	17
Writedown of Broadwater LNG project costs	–	(41)	–	(41)
EBIT[1]	2,326	911	(104)	3,133
Interest expense				(943)
Interest expense of joint ventures				(72)
Interest income and other				54
Income taxes				(602)
Non-controlling interests				(130)
Net Income				1,440
Specific items (net of tax where applicable):				
Calpine bankruptcy settlements				(152)
GTN lawsuit settlement				(10)
Writedown of Broadwater LNG project costs				27
Income tax adjustments				(26)
Comparable Earnings[1]				1,279
Net Income per Share – Basic				$2.53
Comparable Earnings per Share[1][2]				$2.25

Year ended December 31, 2007 *(millions of dollars except per share amounts)*	Pipelines	Energy	Corporate	Total
Comparable EBITDA[1]	3,077	944	(102)	3,919
Depreciation and amortization	(1,021)	(216)	–	(1,237)
Comparable EBIT[1]	2,056	728	(102)	2,682
Specific items:				
Gain on sale of land	–	16	–	16
Fair value adjustments of natural gas inventory in storage and forward contracts	–	10	–	10
EBIT[1]	2,056	754	(102)	2,708
Interest expense				(943)
Interest expense of joint ventures				(75)
Interest income and other				120
Income taxes				(490)
Non-controlling interests				(97)
Net Income				1,223
Specific items (net of tax where applicable):				
Gain on sale of land				(14)
Fair value adjustments of natural gas inventory in storage and forward contracts				(7)
Income tax adjustments				(102)
Comparable Earnings[1]				1,100
Net Income per Share – Basic				$2.31
Comparable Earnings per Share[1][2]				$2.08

[1]Refer to the Non-GAAP Measures section in this MD&A for further discussion of comparable EBITDA, comparable EBIT, EBIT, comparable earnings and comparable earnings per share.

	2009	2008	2007
[2]**Comparable Earnings per Share**[1]	**$2.03**	$2.25	$2.08
Specific items – per share (net of tax where applicable):			
Dilution gain from reduced interest in PipeLines LP	**0.03**	–	–
Calpine bankruptcy settlements	**–**	0.27	–
GTN lawsuit settlement	**–**	0.02	–
Writedown of Broadwater LNG project costs	**–**	(0.05)	–
Fair value adjustments of natural gas inventory in storage and forward contracts	**–**	–	0.01
Gain on sale of land	**–**	–	0.03
Income tax adjustments	**0.05**	0.04	0.19
Net Income per Share	**$2.11**	$2.53	$2.31

RESULTS OF OPERATIONS

In 2009, net income was $1,380 million and net income applicable to common shares was $1,374 million or $2.11 per share compared to net income of $1,440 million or $2.53 per share in 2008. Net income in 2007 was $1,223 million or $2.31 per share.

Net income applicable to common shares in 2009 included $30 million of favourable income tax adjustments arising from a reduction in the Province of Ontario's corporate income tax rates, an $18 million after tax dilution gain resulting from TransCanada's reduced interest in PipeLines LP after a public offering of PipeLines LP common units in fourth quarter 2009, and $1 million of after tax net unrealized gains (2008 – nil; 2007 – net gains of $7 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

Net income in 2008 included $152 million of after tax gains on shares received by GTN and Portland from the Calpine bankruptcy settlements, $10 million after tax of GTN lawsuit settlement proceeds and a $27 million after tax writedown of costs previously capitalized for Broadwater. Net income in 2008 also included $26 million of favourable income tax adjustments from an internal restructuring and realization of losses. Net income in 2007 included $102 million of favourable income tax adjustments relating to changes in Canadian federal and provincial corporate income tax legislation, the resolution of certain tax matters and an internal restructuring, and an after tax gain of $14 million on the sale of land.

Comparable earnings in 2009, 2008 and 2007 were $1,325 million or $2.03 per share, $1,279 million or $2.25 per share and $1,100 million or $2.08 per share, respectively, and excluded the above-noted items.

Comparable earnings increased $46 million and decreased $0.22 per share in 2009 compared to 2008. The increase in comparable earnings reflected:

- Increased comparable EBIT from Pipelines primarily due to higher earnings from the Alberta System revenue requirement settlement and the positive impact in 2009 of a stronger U.S. dollar on Pipelines' U.S. operations, partially offset by increased costs for developing new Pipelines projects, primarily the Alaska pipeline project;
- decreased comparable EBIT from Energy primarily due to lower power prices and a decreased demand for power in Western Power and U.S. Power, reflecting the downturn in the North American economy, partially offset by increased earnings from the start up of Portlands Energy and the Carleton phase of the Cartier Wind project, and higher realized power prices for Bruce Power;
- increased comparable EBIT losses from Corporate primarily due to higher support services costs, reflecting a growing asset base;
- increased interest expense as a result of long-term debt issuances in the second half of 2008 and first quarter 2009 and the negative impact of a stronger U.S. dollar. These increases were partially offset by an increase in capitalized interest relating to Keystone and other capital projects, and reduced losses from changes in the fair value of derivatives used to manage TransCanada's exposure to fluctuating interest rates;
- increased interest income and other due to the positive impact of a weakening U.S. dollar on U.S. dollar working capital balances throughout 2009 and derivatives used to manage the Company's exposure to foreign exchange rate fluctuations;
- decreased income tax expense due to lower pre-tax earnings, higher income tax savings from income tax rate differentials and other positive income tax adjustments in 2009; and
- a reduction in non-controlling interests due to Portland's portion of the Calpine bankruptcy settlements recorded in 2008, partially offset by higher PipeLines LP earnings in 2009.

Comparable earnings increased $179 million or $0.17 per share in 2008 compared to 2007 due to an increase in Energy's comparable EBIT, primarily as a result of higher realized power prices and a full year of earnings from ANR, partially offset by unrealized losses from changes in the fair value of interest rate derivatives.

Earnings per share in 2009 and 2008 was reduced by the increase in the average number of shares outstanding following the Company's issuance of 58.4 million, 35.1 million and 34.7 million common shares in second quarter

2009, fourth quarter 2008 and second quarter 2008, respectively. The shares were issued to partially finance TransCanada's acquisitions and extensive capital growth program.

Results from each of the segments are discussed further in the Pipelines, Energy and Corporate sections of this MD&A.

FORWARD-LOOKING INFORMATION

This MD&A may contain certain information that is forward looking and is subject to important risks and uncertainties. The words "anticipate", "expect", "believe", "may", "should", "estimate", "project", "outlook", "forecast" or other similar words are used to identify such forward-looking information. Forward-looking statements in this document are intended to provide TransCanada security holders and potential investors with information regarding TransCanada and its subsidiaries, including management's assessment of TransCanada's and its subsidiaries' future financial and operational plans and outlook. Forward-looking statements in this document may include, among others, statements regarding the anticipated business prospects and financial performance of TransCanada and its subsidiaries, expectations or projections about the future, strategies and goals for growth and expansion, expected and future cash flows, costs, schedules, operating and financial results and expected impact of future commitments and contingent liabilities. All forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made. Actual results or events may differ from those predicted in these forward-looking statements. Factors that could cause actual results or events to differ materially from current expectations include, among others, the ability of TransCanada to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the operating performance of the Company's pipeline and energy assets, the availability and price of energy commodities, capacity payments, regulatory processes and decisions, changes in environmental and other laws and regulations, competitive factors in the pipeline and energy sectors, construction and completion of capital projects, labour, equipment and material costs, access to capital markets, interest and currency exchange rates, technological developments and economic conditions in North America. By its nature, forward-looking information is subject to various risks and uncertainties, including those material risks discussed in the Pipelines, Energy and Risk Management and Financial Instruments sections in this MD&A, which could cause TransCanada's actual results and experience to differ materially from the anticipated results or expectations expressed. Additional information on these and other factors is available in the reports filed by TransCanada with Canadian securities regulators and with the U.S. Securities and Exchange Commission (SEC). Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this MD&A or otherwise, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

NON-GAAP MEASURES

TransCanada uses the measures "comparable earnings", "comparable earnings per share", "EBITDA", "comparable EBITDA", "EBIT", "comparable EBIT" and "funds generated from operations" in this MD&A. These measures do not have any standardized meaning prescribed by GAAP. They are, therefore, considered to be non-GAAP measures and may not be comparable to similar measures presented by other entities. Management of TransCanada uses these non-GAAP measures to improve its ability to compare financial results among reporting periods and to enhance its understanding of operating performance, liquidity and ability to generate funds to finance operations. These non-GAAP measures are also provided to readers as additional information on TransCanada's operating performance, liquidity and ability to generate funds to finance operations.

EBITDA is an approximate measure of the Company's pre-tax operating cash flow. EBITDA comprises earnings before deducting interest and other financial charges, income taxes, depreciation and amortization, and non-controlling interests. EBIT is a measure of the Company's earnings from ongoing operations. EBIT comprises earnings before deducting interest and other financial charges, income taxes and non-controlling interests.

Management uses the measures of comparable earnings, comparable EBITDA and comparable EBIT to better evaluate trends in the Company's underlying operations. Comparable earnings, comparable EBITDA and comparable EBIT comprise net income applicable to common shares, EBITDA and EBIT, respectively, adjusted for specific items that are significant but are not reflective of the Company's underlying operations in the year. Specific items are subjective, however, management uses its judgement and informed decision-making when identifying items to be excluded in calculating comparable earnings, comparable EBITDA and comparable EBIT, some of which may recur. Specific items may include but are not limited to certain income tax refunds and adjustments, gains or losses on sales of assets, legal and bankruptcy settlements, and certain fair value adjustments. The Segment Results table in this MD&A presents a reconciliation of comparable earnings, comparable EBITDA, comparable EBIT and EBIT to net income and net income applicable to common shares. Comparable earnings per share is calculated by dividing comparable earnings by the weighted average number of common shares outstanding for the year.

Funds generated from operations comprises net cash provided by operations before changes in operating working capital. A reconciliation of funds generated from operations to net cash provided by operations is presented in the Summarized Cash Flow table in the Liquidity and Capital Resources section of this MD&A.

OUTLOOK

TransCanada's corporate strategy is underpinned by long-term growth, focusing on its core strengths in its Pipelines and Energy businesses. In 2010 and beyond, TransCanada expects net income and operating cash flow, combined with a strong balance sheet and proven ability to access capital markets, to provide the financial resources needed to complete its current capital expenditure program, continue to pursue long-term growth opportunities and create additional value for its shareholders. This strategy will be executed with the same discipline and deliberate manner that have characterized TransCanada's current capital expenditure program. TransCanada believes this prudence is especially important in the current economic environment in North America. In 2010, the Company will significantly advance its capital program and continue to implement its strategy to grow the Pipelines and Energy businesses as discussed in the TransCanada's Strategy section of this MD&A.

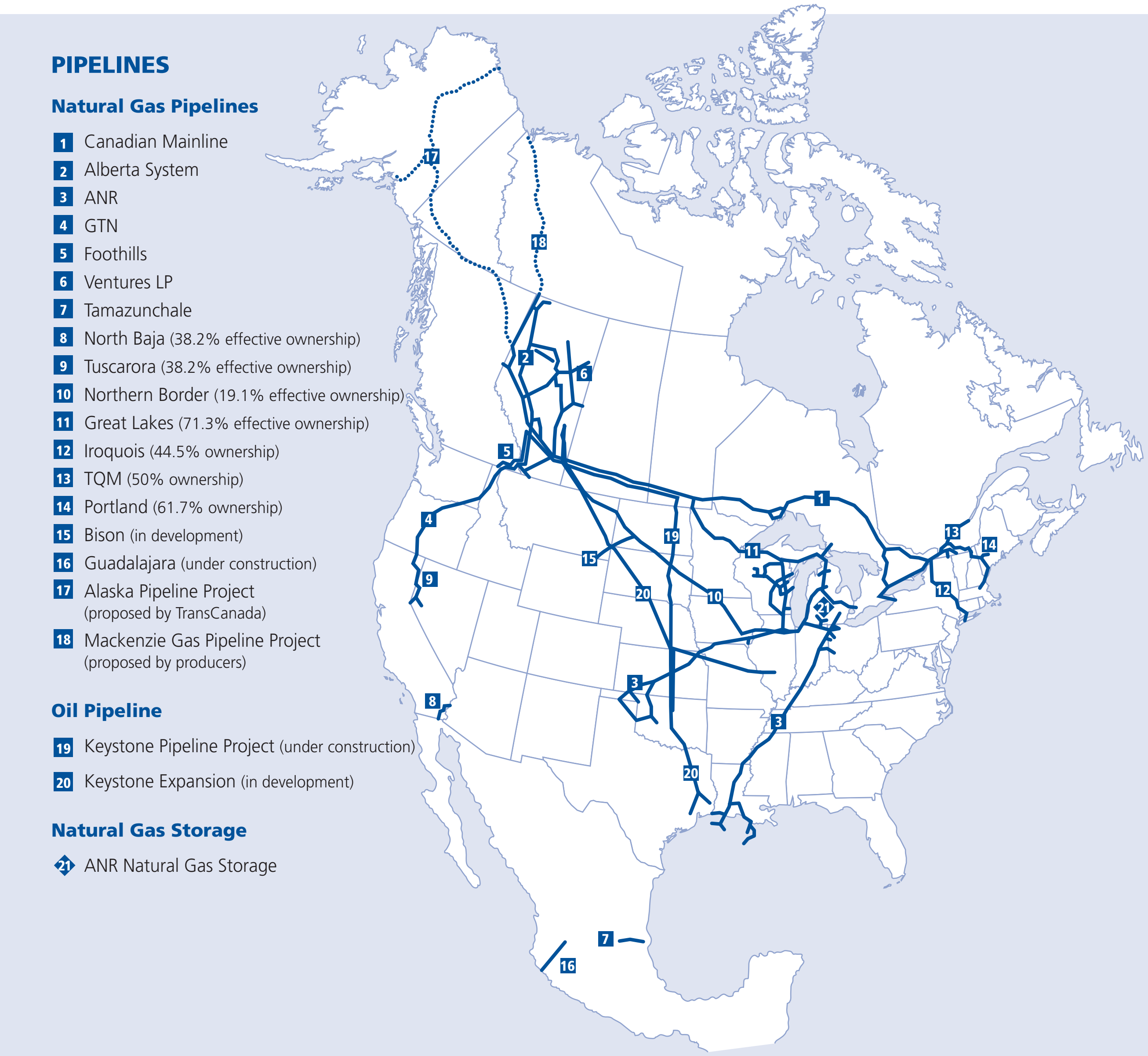
In 2010, the Pipelines segment is expected to begin generating EBITDA from the initial phase of Keystone. Keystone's EBITDA will increase as additional phases are completed and brought into service. Pipelines' EBITDA may be affected by the expiry of long-term contracts, variances in throughput volume particularly on the U.S. pipelines, customer settlements and decisions made by applicable regulatory authorities.

Energy's EBITDA in 2010 will be affected by commodity price changes in instances where TransCanada has not entered into contracts that manage these fluctuations or in circumstances where existing sales contracts expire and are replaced with new contracts entered into at prevailing market prices. Energy's EBITDA will also be impacted by fluctuations in capacity prices in the New York City market where Ravenswood operates and in New England. Furthermore, Energy's EBITDA in 2010 will be positively impacted by assets that were placed in service during 2009 and assets that are expected to be placed in service in 2010.

TransCanada also expects earnings in 2010 to be impacted by a reduction in capitalized interest and an increase in depreciation as new assets are placed into service.

On a consolidated basis, the impact of changes in the value of the U.S. dollar on U.S. Pipelines and Energy EBIT is largely offset by the impact of the changes in the value of the U.S. dollar on U.S. dollar interest expense. The resultant net exposure is managed using derivatives, effectively reducing the Company's exposure to changes in foreign exchange rates. The average U.S. dollar exchange rate for the year ended December 31, 2009 was 1.14 (2008 and 2007 – 1.07).

The Company's results in 2010 may be affected by a number of factors and developments as discussed throughout this MD&A including, without limitation, the factors and developments discussed in the Forward-Looking Information, Pipelines – Business Risks and Energy – Business Risks sections. Refer to the Pipelines – Outlook and Energy – Outlook sections of this MD&A for further discussion of outlook. Commencing January 1, 2011, the Company's results will be impacted by the adoption of International Financial Reporting Standards (IFRS) as discussed in the Accounting Changes – Future Accounting Changes section in this MD&A.



The following pipelines are owned 100 per cent by TransCanada unless otherwise stated.

CANADIAN MAINLINE The Canadian Mainline is a 14,101 km (8,762 miles) natural gas transmission system in Canada extending from the Alberta/Saskatchewan border east to the Québec/Vermont border and connects with other natural gas pipelines in Canada and the U.S.

ALBERTA SYSTEM The Alberta System is a 23,905 km (14,854 miles) natural gas transmission system in Alberta that connects with the Canadian Mainline and Foothills natural gas pipelines and with third-party natural gas pipelines.

ANR ANR is a 17,000 km (10,563 miles) transmission system that transports natural gas from producing fields located primarily in Texas, Oklahoma, the Gulf of Mexico and Louisiana to markets located mainly in Wisconsin, Michigan, Illinois, Ohio and Indiana. ANR also owns and operates regulated underground natural gas storage facilities in Michigan with a total working capacity of 250 Bcf.

GTN GTN is a 2,174 km (1,351 miles) transmission system linking Foothills and Rocky Mountain sourced natural gas with third-party natural gas pipelines in Washington, Oregon and California, and with Tuscarora.

FOOTHILLS Foothills is a 1,241 km (771 miles) transmission system in Western Canada carrying natural gas for export from central Alberta to the U.S. border to serve markets in the U.S. Midwest, Pacific Northwest, California and Nevada.

VENTURES LP Ventures LP is comprised of a 161 km (100 miles) pipeline supplying natural gas to the oilsands region near Fort McMurray, Alberta and a 27 km (17 miles) pipeline supplying natural gas to a petrochemical complex at Joffre, Alberta.

TAMAZUNCHALE Tamazunchale is a 130 km (81 miles) natural gas pipeline in east central Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi.

NORTH BAJA Owned 100 per cent by PipeLines LP, North Baja is a natural gas transmission system extending 129 km (80 miles) from Ehrenberg, Arizona to Ogilby, California and connecting with a third-party natural gas pipeline system in Mexico. TransCanada operates North Baja and effectively owns 38.2 per cent of the system through its 38.2 per cent interest in PipeLines LP.

TUSCARORA Owned 100 per cent by PipeLines LP, Tuscarora is a 491 km (305 miles) pipeline system transporting natural gas from GTN at Malin, Oregon, to Wadsworth, Nevada, with delivery points in northeastern California and northwestern Nevada. TransCanada operates Tuscarora and effectively owns 38.2 per cent (2008 – 32.1 per cent) of the system through its 38.2 per cent (2008 – 32.1 per cent) interest in PipeLines LP.

NORTHERN BORDER Owned 50 per cent by PipeLines LP, Northern Border is a 2,250 km (1,398 miles) natural gas transmission system serving the U.S. Midwest. TransCanada operates Northern Border and effectively owns 19.1 per cent (2008 – 16.1 per cent) of the system through its 38.2 per cent (2008 – 32.1 per cent) interest in PipeLines LP.

GREAT LAKES Owned 53.6 per cent by TransCanada and 46.4 per cent by PipeLines LP, Great Lakes is a 3,404 km (2,115 miles) natural gas transmission system serving markets in Central Canada and the midwestern U.S. TransCanada operates Great Lakes and effectively owns 71.3 per cent (2008 – 68.5 per cent) of the system through its direct ownership interest and its 38.2 per cent (2008 – 32.1 per cent) interest in PipeLines LP.

IROQUOIS Owned 44.5 per cent by TransCanada, Iroquois is a 666 km (414 miles) pipeline system that connects with the Canadian Mainline near Waddington, New York, and delivers natural gas to customers in the northeastern U.S.

TQM Owned 50 per cent by TransCanada, TQM is a 572 km (355 miles) pipeline system that connects with the Canadian Mainline and transports natural gas from Montréal to Québec City in Québec, and connects with Portland. TQM is operated by TransCanada.

PORTLAND Owned 61.7 per cent by TransCanada, Portland is a 474 km (295 miles) pipeline that connects with TQM near East Hereford, Québec and delivers natural gas to customers in the northeastern U.S. Portland is operated by TransCanada.

TRANSGAS Owned 46.5 per cent by TransCanada, TransGas is a 344 km (214 miles) natural gas pipeline system extending from Mariquita to Cali in Colombia.

GAS PACIFICO/INNERGY Owned 30 per cent by TransCanada, Gas Pacifico is a 540 km (336 miles) natural gas pipeline extending from Loma de la Lata, Argentina to Concepción, Chile. TransCanada also has a 30 per cent ownership interest in INNERGY, an industrial natural gas marketing company based in Concepción that markets natural gas transported on Gas Pacifico.

BISON Once completed, the Bison natural gas pipeline will extend 487 km (303 miles) from the Powder River Basin in Wyoming to Northern Border in North Dakota.

KEYSTONE Owned 100 percent (December 31, 2008 – 62 per cent) by TransCanada, Keystone is a 3,456 km (2,147 miles) oil pipeline that will initially transport crude oil from Hardisty, Alberta to U.S. Midwest markets at Wood River and Patoka, Illinois, and to Cushing, Oklahoma. In addition, a 2,720 km (1,690 miles) expansion to the Gulf Coast is under development.

GUADALAJARA The Guadalajara natural gas pipeline is under construction and when completed will extend approximately 305 km (190 miles) from Manzanillo to Guadalajara in Mexico.

PIPELINES – HIGHLIGHTS

- Comparable EBITDA from Pipelines was $3.1 billion in 2009, an increase of $0.1 billion from $3.0 billion in 2008.
- The Company invested $3.9 billion in Pipelines capital projects in 2009, including completion of the first phase of construction of Keystone to Wood River and Patoka, Illinois, for approximately $2.5 billion. The Company also completed the first phase and commenced construction on the second phase of the Alberta System's North Central Corridor expansion at a total capital cost of approximately $600 million to the end of 2009. The expected total capital cost for the North Central Corridor project is approximately $800 million.
- During 2009, TransCanada negotiated a Rate Design Settlement for the Alberta System, which provided for a new rate design for the existing system and expansions. This settlement addresses the evolving nature of the Alberta System and the commercial integration of ATCO Pipelines.
- In December 2009, a Joint Review Panel of the Canadian government released a report on environmental and socio-economic factors relating to the Mackenize Gas Pipeline (MGP) project. The report has been submitted to the National Energy Board of Canada (NEB) as part of the review process for approval of the project. A decision is expected by fourth quarter 2010.
- In October 2009, the NEB issued a ruling that its adjustment formula for the rate of return on common equity (ROE) would no longer be in effect. The decision affects the calculation of future tolls for TransCanada's NEB-regulated natural gas pipelines. Prior to this ruling, the NEB issued a decision awarding TQM a 6.4 per cent after-tax weighted average cost of capital (ATWACC) for 2007 and 2008.
- In April 2009, TransCanada received a decision from the NEB affirming that the Alberta System is within federal jurisdiction and is subject to regulation by the NEB.
- In 2009, TransCanada acquired ConocoPhillips' remaining interest in Keystone, increasing the Company's ownership to 100 per cent.
- In 2009, as a result of PipeLines LP issuing common units to the public, the Company's interest was reduced to 38.2 per cent and a dilution gain of $29 million was realized.
- In June 2009, TransCanada entered into an agreement with ExxonMobil to jointly advance the Alaska pipeline.

PIPELINES – RESULTS
Year ended December 31 *(millions of dollars)*

	2009	2008	2007
Canadian Pipelines			
Canadian Mainline	**1,133**	1,141	1,207
Alberta System	**728**	692	775
Foothills	**132**	133	135
Other (TQM, Ventures LP)	**59**	50	51
Canadian Pipelines Comparable EBITDA(1)	**2,052**	2,016	2,168
U.S. Pipelines			
ANR	**347**	347	272
GTN(2)	**195**	198	187
Great Lakes	**138**	127	125
PipeLines LP(2)(3)	**84**	70	62
Iroquois	**78**	59	55
Portland(4)	**26**	27	34
International (Tamazunchale, TransGas, Gas Pacifico/INNERGY)	**58**	40	51
General, administrative and support costs(5)	**(17)**	(15)	(17)
Non-controlling interests(2)(6)	**194**	187	187
U.S. Pipelines Comparable EBITDA(1)	**1,103**	1,040	956
Business Development Comparable EBITDA(1)	**(62)**	(37)	(47)
Pipelines Comparable EBITDA(1)	**3,093**	3,019	3,077
Depreciation and amortization	**(1,030)**	(989)	(1,021)
Pipelines Comparable EBIT(1)	**2,063**	2,030	2,056
Specific items:			
Dilution gain from reduced interest in PipeLines LP(3)(7)	**29**	–	–
Calpine bankruptcy settlements(8)	**–**	279	–
GTN lawsuit settlement	**–**	17	–
Pipelines EBIT(1)	**2,092**	2,326	2,056

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of comparable EBITDA, comparable EBIT and EBIT.

(2) GTN's results include North Baja until July 1, 2009 when it was sold to PipeLines LP.

(3) Effective November 18, 2009, PipeLines LP's results reflected TransCanada's effective ownership in PipeLines LP of 38.2 per cent. From July 1, 2009 to November 17, 2009, TransCanada's ownership interest in PipeLines LP was 42.6 per cent. From February 22, 2007 to June 30, 2009, TransCanada's ownership interest in PipeLines LP was 32.1 per cent. From January 1, 2007 to February 22, 2007, TransCanada's ownership interest in PipeLines LP was 13.4 per cent.

(4) Portland's results reflect TransCanada's 61.7 per cent ownership interest.

(5) Represents certain costs associated with supporting the Company's Canadian and U.S. Pipelines.

(6) Non-controlling interests reflects EBITDA for the portions of PipeLines LP and Portland not owned by TransCanada.

(7) As a result of PipeLines LP issuing common units to the public, the Company's ownership interest in PipeLines LP was reduced to 38.2 per cent from 42.6 per cent and a dilution gain of $29 million was realized.

(8) GTN and Portland received shares of Calpine with an initial value of $154 million and $103 million, respectively, as a result of the bankruptcy settlements with Calpine. These shares were subsequently sold for an additional gain of $22 million.

Pipelines generated comparable EBIT of $2,063 million in 2009 compared to $2,030 million in 2008. Comparable EBIT in 2009 excluded the $29 million pre-tax dilution gain resulting from TransCanada's reduced interest in PipeLines LP, which occurred following the public issuance of common units by PipeLines LP in November 2009. Comparable EBIT in 2008 excluded the $279 million of gains received by Portland and GTN from the bankruptcy settlements with Calpine and the $17 million of proceeds received by GTN from a lawsuit settlement with a software supplier. Comparable EBIT in 2007 was $2,056 million.

Wholly Owned Canadian Pipelines Net Income
Year ended December 31 *(millions of dollars)*

	2009	2008	2007
Canadian Mainline	**273**	278	273
Alberta System	**168**	145	138
Foothills	**23**	24	26

PIPELINES – FINANCIAL ANALYSIS

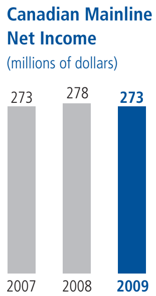
Canadian Mainline The Canadian Mainline is regulated by the NEB, which sets tolls that provide TransCanada with the opportunity to recover projected costs of transporting natural gas, including a return on the Canadian Mainline's average investment base. The NEB also approves new facilities before construction begins. Canadian Mainline's EBITDA is affected by changes in investment base, the ROE, the level of deemed common equity, potential incentive earnings and changes in the level of depreciation, financial charges and income taxes recovered in revenue on a flow-through basis.

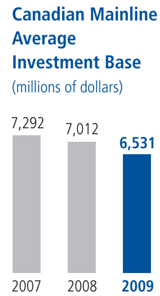
The Canadian Mainline currently operates under a five year tolls settlement effective from 2007 to 2011. The cost of capital reflects an ROE as determined by the NEB's ROE formula on deemed common equity of 40 per cent.

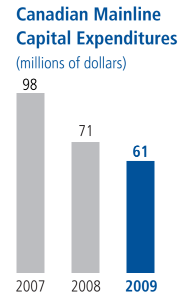
The tolls settlement also established certain elements of the Canadian Mainline's fixed operating, maintenance and administration (OM&A) costs for each of the five years. The variance between actual and agreed-upon OM&A costs accrued entirely to TransCanada from 2007 to 2009, and will be shared equally between TransCanada and its customers in 2010 and 2011. All other cost elements of the revenue requirement are treated on a flow-through basis. The settlement also allows for performance-based incentive arrangements that the Company believes are mutually beneficial to TransCanada and its customers.

Net income of $273 million in 2009 was $5 million lower than $278 million in 2008. The decrease was primarily the result of a lower average investment base and a lower ROE of 8.57 per cent in 2009 compared to 8.71 per cent in 2008, partially offset by higher OM&A cost savings. Net income of $278 million in 2008 was $5 million higher than $273 million in 2007 primarily due to higher performance-based incentives, increased OM&A cost savings and an ROE of 8.71 per cent in 2008 compared to 8.46 per cent in 2007. These increases were partially offset by a lower average investment base.

Comparable EBITDA of $1,133 million in 2009 was $8 million lower than $1,141 million in 2008. The decrease was primarily due to lower revenues as a result of recovery of a lower overall return on a reduced average investment base and a lower ROE in 2009. The decrease in revenues was partially offset by higher OM&A cost savings and recovery of higher depreciation in 2009. EBITDA of $1,141 million in 2008 was $66 million lower than $1,207 million in 2007 primarily due to lower revenues as a result of the recovery of lower depreciation, financial charges and income taxes in 2008. The decrease in revenues was partially offset by higher EBITDA from performance-based incentives, OM&A cost savings and higher ROE.







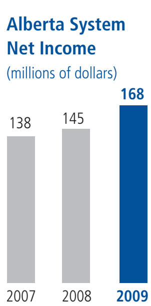
Alberta System Effective April 29, 2009, the Alberta System became federally regulated by the NEB under the *National Energy Board Act* (Canada). The Alberta System was previously regulated by the Alberta Utilities Commission (AUC), primarily under the provisions of the *Gas Utilities Act* (Alberta) and *Pipeline Act* (Alberta). The Alberta System's EBITDA is affected by changes in investment base, the ROE, the level of deemed common equity, potential incentive earnings and changes in the level of depreciation, financial charges and income taxes recovered in revenue on a flow-through basis.

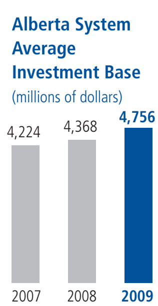
The Alberta System operates under the 2008 - 2009 Revenue Requirement Settlement originally approved by the AUC in December 2008 and subsequently approved by the NEB following the Alberta System's transfer to federal jurisdiction. In December 2009, the NEB approved TransCanada's application to establish final 2009 tolls. In 2007, the Alberta System operated under the 2005 - 2007 Revenue Requirement Settlement approved by the AUC in June 2005.

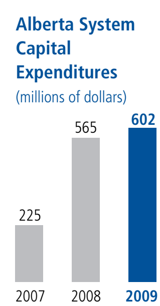
As part of the 2008 - 2009 Revenue Requirement Settlement, fixed amounts were established for ROE, income taxes and certain OM&A costs. Any variances between actual costs and those agreed to in the settlement accrued to TransCanada, subject to an ROE and income tax adjustment mechanism that accounted for variances between actual and settlement rate base, and income tax assumptions. The other cost elements of the settlement were treated on a flow-through basis.

The Alberta System's net income of $168 million in 2009 was $23 million higher than in 2008, primarily due to higher settlement earnings and a higher average investment base in 2009. Net income of $145 million in 2008 was $7 million higher than in 2007 due to increased earnings as a result of the 2008 - 2009 Revenue Requirement Settlement. Earnings in 2007 reflected an ROE of 8.51 per cent on deemed common equity of 35 per cent.

The Alberta System's comparable EBITDA of $728 million in 2009 was $36 million higher than in 2008, primarily due to higher settlement earnings and a higher average investment base in 2009 as well as increased revenues as a result of the recovery of higher financial charges, partially offset by lower income taxes. EBITDA of $692 million in 2008 was $83 million lower than in 2007. The decrease was due to lower revenues as a result of the recovery of lower depreciation, income taxes and financial charges, partially offset by increased earnings as a result of the 2008 - 2009 Revenue Requirement Settlement.







Other Canadian Pipelines Comparable EBITDA from Other Canadian Pipelines was $59 million in 2009 compared to $50 million in 2008. The increase was primarily due to the NEB decision reached in March 2009 on TQM's cost of capital for the years 2007 and 2008. EBITDA was $50 million in 2008 compared to $51 million in 2007.

ANR The operations of ANR are regulated primarily by the U.S. Federal Energy Regulatory Commission (FERC). ANR provides natural gas transportation, storage and various capacity-related services to a variety of North American customers. ANR's transmission system has a peak-day capacity of 6.8 billion cubic feet per day (Bcf/d). Due to the seasonal nature of its business, ANR's volumes and revenues are generally higher in the winter months. ANR also owns and operates 250 Bcf of regulated underground natural gas storage facilities in Michigan. ANR's natural gas storage and transportation services operate under current FERC-approved tariffs. These tariffs include maximum and minimum rates for services and permit ANR to discount or negotiate rates on a non-discriminatory basis.

ANR Pipeline Company (ANR Pipeline) rates were established pursuant to a settlement approved by the FERC effective November 1997. ANR Storage Company's rates were established pursuant to a settlement approved by the FERC effective June 1990. None of ANR's FERC-regulated operations are required to file for new rates at any time in the future, nor are any of the operations prohibited from filing a rate case.

ANR's comparable EBITDA in 2009 was $347 million, which was consistent with 2008. Higher transportation and storage revenues, as a result of expansion projects, increased utilization and favourable pricing on existing capacity, and the positive impact of a stronger U.S. dollar in 2009 were offset by lower incidental natural gas sales, primarily due to lower prices, and higher OM&A and business development costs. Comparable EBITDA in 2008 was $347 million compared to $272 million in 2007. The increase was primarily due to a full year of earnings in 2008 and increased revenue from new growth projects, partially offset by higher OM&A costs.

GTN GTN is regulated by the FERC and is operated in accordance with FERC-approved tariffs that establish maximum and minimum rates for various services. GTN's pipeline rates were established pursuant to a settlement approved by the FERC in January 2008, and these rates were effective January 1, 2007. Under the settlement, a five-year moratorium commencing January 1, 2007 was established during which GTN and the settling parties are prohibited from taking certain actions, including any filings to adjust rates. The settlement also requires GTN to file for new rates to be in effect no later than January 1, 2014. GTN is permitted to discount or negotiate these rates on a non-discriminatory basis. GTN's EBITDA is affected by variations in contracted volume levels, volumes delivered and prices charged under the various service types, as well as by variations in the costs of providing services.

GTN's comparable EBITDA was $195 million in 2009, a decrease of $3 million compared to 2008. The decrease was primarily due to the sale of North Baja to PipeLines LP in 2009, partially offset by the positive impact of a stronger U.S. dollar in 2009. GTN's EBITDA was $198 million in 2008, an increase of $11 million compared to 2007 primarily due to lower OM&A expenses.

Other U.S. Pipelines Comparable EBITDA from other U.S. Pipelines was $561 million in 2009 compared to $495 million in 2008. The increase was primarily due to the positive impact of a stronger U.S. dollar in 2009, the July 2009 PipeLines LP acquisition of North Baja, increased revenues from Gas Pacifico resulting from a new transportation agreement and higher short-term revenues from Iroquois. EBITDA was $497 million in 2007.

Business Development Pipelines' business development comparable EBITDA losses increased $25 million in 2009 compared to 2008 primarily due to higher business development costs related to the Alaska pipeline project.

Depreciation and Amortization Depreciation increased $41 million in 2009 compared to 2008 primarily due to a stronger U.S. dollar in 2009. The $32 million decrease in depreciation in 2008 compared to 2007 was primarily due to lower depreciation for the Alberta System.

PIPELINES – OPPORTUNITIES AND DEVELOPMENTS

Crude Oil

Keystone In August 2009, TransCanada purchased ConocoPhillips' remaining approximate 20 per cent interest in Keystone for US$553 million and the assumption of US$197 million of short-term debt. TransCanada now owns 100 per cent of Keystone.

In 2008, TransCanada entered into an agreement with ConocoPhillips to increase its equity ownership in Keystone to approximately 80 per cent from 50 per cent, with ConocoPhillips' equity ownership in Keystone being reduced concurrently to approximately 20 per cent from 50 per cent. In 2008 and prior to August 2009, TransCanada funded 100 per cent of the construction expenditures until the participants' cumulative project capital contributions were aligned with their revised ownership interests. In 2009, prior to August, TransCanada funded $1.3 billion of cash calls for Keystone, resulting in the Company acquiring an incremental increase in ownership of approximately 18 per cent for $313 million. In 2008, the Company funded $362 million of cash calls, resulting in an incremental increase in ownership of approximately 12 per cent for $176 million. TransCanada's ownership interest was approximately 80 per cent and 62 per cent in August 2009 and at December 31, 2008, respectively.

After gaining regulatory approval in both Canada and the U.S., construction of Keystone began in May 2008. Commissioning of the first phase of Keystone, extending from Hardisty to Wood River and Patoka with an initial nominal capacity of 435,000 Bbl/d began in late 2009.

In June 2008, Keystone received approval from the NEB to add new pumping facilities to accommodate deliveries to the Cushing market. The second phase of Keystone is expected to expand nominal capacity to 591,000 Bbl/d and extend the pipeline to Cushing, with commissioning expected to commence in late 2010 and commercial in service expected to commence in first quarter 2011.

After an open season conducted during third quarter 2008, Keystone secured additional firm, long-term shipper contracts on its system. With these commitments, Keystone filed the necessary regulatory applications in Canada and the U.S. for approval to construct and operate the expansion of the pipeline system that is expected to provide additional capacity from Western Canada to the U.S. Gulf Coast in early 2013, increasing the total commercial capacity of Keystone to approximately 1.1 million Bbl/d. In September 2009, the NEB held a hearing to review the application for the new Canadian facilities required for the Keystone Gulf Coast expansion. The NEB is expected to issue a decision in first quarter 2010 on TransCanada's application to construct and operate the facilities, including the proposed tolling methodology. Facility permits for the U.S. portion of the expansion are expected by fourth quarter 2010. Construction of the expansion facilities is anticipated to commence in first quarter 2011 following the receipt of the necessary regulatory approvals.

The capital cost of Keystone, including expansion to the Gulf Coast, if approved, is expected to be approximately US$12 billion with approximately US$5 billion spent to date. At December 31, 2009, costs of $470 million related to the Keystone expansion to the Gulf Coast are included in intangibles and other assets. Capital costs related to the construction of Keystone are subject to capital cost risk- and reward-sharing mechanisms with TransCanada's customers.

The NEB issued approval to commence operations, including commissioning activities, for the Canadian portion of Keystone's facilities, subject to certain conditions. The approval for the Canadian segment of the pipeline was granted for a period ending approximately nine months from commencement of commercial in service, at a reduced maximum operating pressure (MOP), which will reduce throughput capacity below initial nominal capacity of 435,000 Bbl/d. Prior to the conclusion of this nine month period, Keystone is required to run additional in-line inspections on this segment. These inspections and any remedial work are expected to be completed within this nine month period. Following these activities, TransCanada expects the MOP restriction to be lifted.

TransCanada expects Keystone to commence delivery of crude oil from Hardisty, Alberta, to U.S. Midwest markets at Wood River and Patoka, Illinois beginning mid-2010, and to Cushing, Oklahoma in first quarter 2011. Pending regulatory approval, an expansion of the system to the U.S. Gulf Coast is expected to commence the delivery of crude oil in early 2013.

TransCanada expects Keystone to begin generating EBITDA in 2010 with earnings increasing through 2011, 2012 and 2013 as expansion phases commence delivery of crude oil. Contracted volumes of 217,500 Bbl/d will increase to 910,000 Bbl/d from 2010 to 2013 as commercial in service of the Cushing and Gulf Coast phases commence. Based on current long-term commitments, Keystone is expected to generate EBITDA of approximately US$1.2 billion in 2013, its first full year of commercial operation servicing both the U.S. Midwest and Gulf Coast markets. If volumes were to increase to 1.1 million Bbl/d, the full commercial design of the system, Keystone would generate annual EBITDA of approximately US$1.5 billion. Keystone volumes could be economically expanded to 1.5 million Bbl/d from 1.1 million Bbl/d in response to additional market demand.

Natural Gas

NEB Changes

Changes to NEB ROE Formula In March 2009, the NEB initiated a process to consider the continuing applicability of its RH-2-94 Decision. This decision established an ROE adjustment formula tied to Government of Canada bond yields and had formed the basis for determining tolls for certain pipelines under NEB jurisdiction since 1995. In October 2009, the NEB determined that the RH-2-94 Decision would no longer be in effect. The NEB decided that the cost of capital would be determined by negotiations between pipeline companies and their shippers or by the NEB if a pipeline company files a cost of capital application. This decision affects certain NEB-regulated pipelines, including the Canadian Mainline, Alberta System, Foothills and TQM. TransCanada will be working with customers and interested parties to determine the cost of capital to be used in calculating tolls beginning in 2010 for the Alberta System, Foothills and TQM, and for the Canadian Mainline upon expiry of its existing settlement. If agreements cannot be reached, applications will be filed with the NEB requesting an appropriate return on capital.

In November 2009, the Canadian Association of Petroleum Producers and the Industrial Gas Users Association sought leave to appeal the October 2009 NEB decision to the Federal Court of Appeal and named the NEB as the sole respondent. In January 2010, TransCanada was granted respondent status in the matter and in February 2010 filed its submission opposing the leave application.

Asset Retirement Obligations In May 2009, the NEB issued a decision on the Land Matters Consultation Initiative with respect to financial issues related to pipeline abandonment. All pipeline companies regulated under the *National Energy Board Act* (Canada) will be required to comply with the framework and action plan set out in the decision. The NEB's goal is to have pipeline companies begin collecting and setting aside funds to cover future abandonment costs no later than mid-2014. There are several filing deadlines in the action plan with which NEB regulated pipeline companies have to comply, including deadlines for preparing and filing an estimate of the abandonment costs, developing a proposal for collection of funds through tolls or some other satisfactory method and developing a proposed process to set aside the funds collected. As a result of this decision, TransCanada has initiated a project to estimate the abandonment costs on its NEB-regulated pipelines. The estimate will be filed with the NEB for approval by May 31, 2011.

Canadian Mainline The Canadian Mainline will continue to base its return on the NEB's ROE formula for 2010 and 2011 in accordance with the terms of the current Canadian Mainline tolls settlement. In December 2009, the NEB approved TransCanada's application for 2010 final tolls for the Canadian Mainline's transportation service, effective January 1, 2010. The 2010 calculated ROE for the Canadian Mainline will be 8.52 per cent, a decrease from 8.57 per cent in 2009.

Alberta System Effective April 29, 2009, the Alberta System became regulated by the NEB under the *National Energy Board Act* (Canada). The Alberta System was previously regulated by the AUC. Under federal regulation, TransCanada is able to apply to the NEB for approval to extend the Alberta System across provincial borders, allowing the Company to provide service to producers outside of Alberta.

In September 2009, TransCanada began construction on the final phase of the North Central Corridor natural gas pipeline, a 300 km (186 miles) extension of the Alberta System's northern section. This final phase is expected to be completed by April 2010. The initial phase was completed and operational in 2009. The North Central Corridor pipeline will provide capacity to accommodate increasing natural gas supply in northwest Alberta and northeast B.C. and growing markets in Alberta, and to offset declining natural gas supply in northeast Alberta while delivering more natural gas to the Alberta/Saskatchewan border. The total capital cost of the project is estimated to be approximately $800 million.

TransCanada expects producers will continue to explore and develop new gas fields in Western Canada, particularly in northeastern B.C. and the west and central foothills regions of Alberta. There is also expected to be significant exploration and development activity aimed at unconventional resources such as coalbed methane and shale gas. The emergence of economically producible unconventional gas from B.C. shale gas supply, including the Montney and Horn River regions, has the potential to become a significant new opportunity for the Alberta System. While these areas are in their early stages of development, they appear to be comparable to U.S. shale gas supply volumes. Current estimates of the potential gas supply from these two areas range from 70 trillion cubic feet to 150 trillion cubic feet.

In November 2009, the NEB concluded a public hearing on TransCanada's application for approval to construct and operate the Groundbirch pipeline, which is comprised of a 77 km (48 miles) natural gas pipeline and related above-ground facilities. TransCanada has entered into firm transportation agreements with Groundbirch customers that are expected to increase to 1.1 Bcf/d by 2014. The Groundbirch pipeline, if approved, will be an extension of the Alberta System and will connect natural gas supply primarily from the Montney shale gas formation in northeast B.C. to existing infrastructure in northwest Alberta. Construction of the Groundbirch pipeline is expected to commence in July 2010 with completion anticipated in November 2010. A decision from the NEB is expected in first quarter 2010. The total capital cost of the project is estimated to be $200 million.

In May 2009, TransCanada filed a Project Description with the NEB to initiate a regulatory review of the proposed Horn River project, which comprises construction of a 72 km (45 miles) natural gas pipeline and related facilities, including above-ground facilities, and acquisition of the existing 83 km (52 miles) Ekwan pipeline from EnCana Corporation. The Horn River project would connect new shale natural gas supply in the Horn River basin north of Fort Nelson, B.C. to the Alberta System. Total contractual commitments for Horn River have increased to 503 million cubic feet per day (mmcf/d) by 2014 from 378 mmcf/d as a result of newly contracted volumes from a recently announced natural gas processing facility that will be located in the Horn River area. As part of the Horn River project, in November 2009, TransCanada entered into an agreement to acquire the Ekwan pipeline, which is expected to close in September 2011. In February 2010, the Company filed an application with the NEB for approval to construct and operate the Horn River project. Subject to regulatory approvals, the Horn River project is anticipated to commence operations in second quarter 2012. The total capital cost of the project is expected to be approximately $310 million.

Both the Groundbirch and Horn River projects are proposed as extensions to the Alberta System, which would provide B.C. producers with direct integrated gas transmission service from receipt points in B.C. These pipeline projects would also increase netbacks to producers and throughput on the Alberta System and increase usage of the Nova Inventory Transfer commercial hub that is used by buyers and sellers of natural gas throughout North America.

NOVA Gas Transmission Ltd. (NGTL) and Canadian Utilities Limited (ATCO Pipelines) continue to work towards obtaining the necessary regulatory approvals to provide commercial and operational integrated services to shippers on the Alberta System and the ATCO Pipelines system in Alberta. Final decisions from the AUC and NEB are expected by mid-2010 with implementation occurring within 12 months following receipt of required regulatory approvals. The integration of commercial and operational services on the Alberta System and ATCO Pipelines system will create the effect of a single integrated natural gas transmission system in Alberta, resulting in more efficient transportation of natural gas for customers.

During 2009, TransCanada negotiated an Alberta System Rate Design Settlement with all key stakeholders. This rate design addresses the evolving nature of the Alberta System and the commercial and operational integration of ATCO Pipelines. It also incorporates a single delivery service for all delivery points resulting from the amalgamation of the current intra-Alberta and export delivery services. The changes are expected to improve the Alberta System's services by making them more consistent and adding flexibility for customers. The Company filed a combination application with the NEB on November 27, 2009 for approval of both the Rate Design Settlement and the integration of commercial and operational services on the Alberta System and ATCO Pipelines' system in Alberta. A final decision is expected from the NEB by mid-2010 with implementation occurring within the 12 months following approval.

TQM In March 2009, TQM received the NEB's decision on its cost of capital application for 2007 and 2008, which requested an 11 per cent return on 40 per cent deemed common equity. The NEB set a 6.4 per cent ATWACC for each of the two years, which equates to a 9.85 per cent return on 40 per cent deemed common equity in 2007 and a 9.75 per cent return on 40 per cent deemed common equity in 2008. Prior to the decision, TQM was subject to the NEB ROE formula of 8.46 per cent and 8.71 per cent for 2007 and 2008, respectively, on deemed common equity of 30 per cent. In June 2009, the NEB approved TQM's final tolls for 2007 and 2008, which reflected the 6.4 per cent ATWACC.

Ventures LP In May 2009, the AUC concluded an investigation of the rates on Ventures LP and determined they are unjust and unreasonable. The AUC sought an Order in Council from the Alberta government to proceed with a process to establish new rates. In September 2009, the Alberta Court of Appeal granted Ventures LP leave to appeal the AUC's decision. The appeal is expected to be heard in March 2010.

ANR In 2009, ANR received regulatory approval of the Wisconsin 2009 Project to construct a pipeline with capacity of approximately 97 mmcf/d that will deliver incremental natural gas to Wisconsin markets. A portion of the pipeline was placed in service in 2009. The remainder of the project is expected to be completed in 2010.

In 2009, four new interstate pipelines made supply interconnections with ANR's southeast leg, comprising a combined interconnect capacity of 1.5 Bcf/d. The interconnections increased ANR's access to natural gas supply from the mid-continent shale and Rocky Mountain regions, and from a Gulf Coast LNG regassification terminal.

In September 2008, certain portions of ANR's Gulf of Mexico offshore facilities were damaged by Hurricane Ike. The Company estimates its total exposure to damage costs to be approximately US$30 million to US$40 million, mainly to replace, repair and abandon capital assets, including the estimated cost to abandon an offshore platform. At December 31, 2009, related capital expenditures of US$11 million (2008 – US$2 million) and OM&A costs of US$7 million (2008 – US$6 million) had been incurred. The remaining costs are expected to be incurred in 2010 and 2011, with the majority to be incurred in 2011. Service on the offshore facilities has been restored and related throughput volumes have returned to pre-hurricane levels.

Portland In April 2008, Portland filed a general rate case with the FERC proposing a rate increase of approximately six per cent as well as other changes to its tariff. In May 2009, Portland reached a settlement with its customers on certain short-term issues in its rate case. The partial settlement was filed with the FERC for approval and a decision is expected in 2010. The remaining issues were litigated and Portland received the Initial Decision from the Administrative Law Judge in December 2009. Participants in the rate case have an opportunity to respond to the Initial Decision. The FERC is expected to issue its final decision on the litigated portion of the rate case in fourth quarter 2010.

PipeLines LP/North Baja On July 1, 2009, TransCanada sold North Baja to PipeLines LP. As part of the transaction, TransCanada agreed to amend its incentive distribution rights with PipeLines LP. Under the amendment, TransCanada received additional common units in exchange for a resetting of its incentive distribution rights at a lower percentage which escalates with increases in PipeLines LP's distributions. TransCanada received aggregate consideration totalling approximately US$395 million from PipeLines LP, including US$200 million in cash and 6,371,680 common units of PipeLines LP. TransCanada's ownership in PipeLines LP increased to 42.6 per cent as a result of this transaction and TransCanada continues to operate North Baja. TransCanada's ownership in PipeLines LP was reduced to 38.2 per cent in November 2009 after PipeLines LP's public issuance of common units.

Great Lakes In November 2009, the FERC initiated an investigation to determine whether Great Lakes' rates are just and reasonable. In response, Great Lakes filed a cost and revenue study with the FERC on February 4, 2010. A hearing is scheduled to commence on August 2, 2010, and an Initial Decision is required in November 2010. The impact of the investigation on Great Lakes' rates and revenues is unknown at this time.

Palomar In December 2008, Palomar Gas Transmission LLC applied to the FERC for a certificate to build a 349 km (217 miles) natural gas pipeline extending from GTN in central Oregon, to the Columbia River northwest of Portland. The proposed pipeline has a capacity of up to 1.3 Bcf/d of natural gas. The project is a 50/50 joint venture between GTN and Northwest Natural Gas Co. Palomar is currently in discussions with potential shippers to secure shipping commitments for the project.

Guadalajara In May 2009, TransCanada entered into a contract to build, own and operate a US$320 million pipeline in Mexico, which is supported by a 25 year contract for its entire capacity with the Comisión Federal de Electricidad, Mexico's state-owned electric power company. The Guadalajara pipeline project is a proposed natural gas pipeline of approximately 305 km (190 miles) extending from Manzanillo to Guadalajara. Regulatory approvals were received in December 2009 and construction is underway with an expected in-service date of first quarter 2011.

U.S. Rockies Pipeline Projects The Bison project is a 487 km (303 miles) proposed natural gas pipeline from the Powder River Basin in Wyoming connecting to Northern Border in North Dakota. The FERC issued a Final Environmental Impact Statement in December 2009 and the project is in the final stages of the regulatory approval process. The Company expects to commence construction in May 2010. The pipeline has shipping commitments for approximately 407 mmcf/d and is expected to be placed in service in fourth quarter 2010. The capital cost of the Bison pipeline project is estimated to be US$600 million.

Previously, TransCanada was working to develop the Pathfinder and Sunstone pipeline projects, which were proposed to deliver natural gas from the Rocky Mountains to various U.S. markets. Based on market conditions, TransCanada has elected to consolidate its Rocky Mountain development plans and will pursue additional development opportunities using the Bison pipeline as a platform for medium-term growth.

Alaska Pipeline Project In November 2007, TransCanada submitted an application to the State of Alaska for a license to construct the Alaska pipeline project under the *Alaska Gasline Inducement Act* (AGIA). In January 2008, the State of Alaska determined that TransCanada's application was the only proposal that met all of the state's requirements and the AGIA license was issued to TransCanada in December 2008. Under the AGIA, the State of Alaska has agreed to reimburse a share of TransCanada's eligible pre-construction costs, as they are incurred, and approved by the state to a maximum of US$500 million.

In June 2009, TransCanada entered into an agreement with ExxonMobil to jointly advance the project. A joint project team is developing the engineering, environmental, aboriginal relations and commercial work.

The proposed Alaska pipeline project is a 4.5 Bcf/d natural gas pipeline extending 2,737 km (1,700 miles) from a new natural gas treatment plant at Prudhoe Bay, Alaska to Alberta. This pipeline will provide access to diverse markets across

North America and is expected to have an estimated capital cost of US$32 billion to US$41 billion. The pipeline construction application included provisions to expand capacity up to 5.9 Bcf/d through the addition of compressor stations in Alaska and Canada. The current estimated capital cost for the project is an increase over previously stated estimates. The latest estimate is based on increased costs for oil and gas projects from 2007 to 2009 and a significant increase in the estimated cost of building the gas treatment plant at Prudhoe Bay. TransCanada also proposed an alternate pipeline from Prudhoe Bay to Valdez, Alaska to supply LNG markets with an estimated capital cost of US$20 billion to US$26 billion.

On January 29, 2010, the Alaska pipeline project filed to obtain FERC approval to conduct an open season. If approval is granted, an open season offering is expected to be provided to potential shippers at the end of April 2010 for their assessment until July 2010. Both project options will be offered to shippers as alternative projects and both options have an expected in-service date of 2020. TransCanada is continuing to work with potential shippers for the initial open season.

Mackenzie Gas Pipeline Project The MGP is a proposed 1,200 km (746 miles) natural gas pipeline extending from a point near Inuvik, Northwest Territories to the northern border of Alberta, where it will connect to the Alberta System.

TransCanada's involvement with the MGP arises from a 2003 agreement between the Mackenzie Valley Aboriginal Pipeline Group (APG) and the MGP, whereby TransCanada agreed to finance the APG's one-third share of the pre-development costs associated with the project. These costs, on a cumulative basis, are currently forecast to be between $150 million and $200 million. Under the terms of certain MGP agreements, TransCanada holds an option to acquire up to a five per cent equity ownership in the MGP at the time of the decision to construct it. In addition, TransCanada gains certain rights of first refusal to acquire 50 per cent of any divestitures by existing partners and an entitlement to obtain a one-third interest in all expansion opportunities once the APG reaches a one-third ownership share, with the other natural gas pipeline owners and the APG sharing the balance.

Cumulative advances to the APG by TransCanada totalled $143 million at December 31, 2009 (2008 – $140 million) and are included in intangibles and other assets. These advances constitute a loan to the APG, which becomes repayable only after the natural gas pipeline commences commercial operations. The total amount of the loan is expected to form part of the rate base of the pipeline and to be repaid from the APG's share of future natural gas pipeline revenues or from alternate financing. If the project does not proceed, TransCanada has no recourse against the APG for recovery of advances made.

TransCanada and the other co-venture companies involved in the MGP continue to pursue approval of the proposed project, focusing on obtaining regulatory approval and the Canadian government's support of an acceptable fiscal framework. The regulatory process reached a milestone in late December 2009 with the release of the Joint Review Panel's report on environmental and socio-economic factors relating to the project. The report has been submitted to the NEB as part of the review process required for approval of the project. The NEB review is scheduled to conclude with final arguments in April 2010. A decision by the NEB is currently expected by fourth quarter 2010. Project timing continues to be uncertain. In the event the co-venture group is unable to reach an agreement with the government on an acceptable fiscal framework, the parties will need to determine the appropriate next steps for the project. For TransCanada, this may result in a reassessment of the carrying amount of the APG advances.

PIPELINES – BUSINESS RISKS

Natural Gas Supply, Markets and Competition TransCanada faces competition at both the supply and market ends of its natural gas pipelines systems. This competition comes from other natural gas pipelines accessing the increasingly mature WCSB and markets served by TransCanada's pipelines as well as from natural gas supplies produced in basins not directly served by the Company. Growth in supply and pipeline infrastructure has increased competition throughout

North America. Production in the U.S. has increased, driven primarily by shale gas, while WCSB production has declined. The lower cost shale gas in the U.S. has resulted in an increase in competition between supply basins, changes to traditional flow patterns and an increase in choices for customers. This change has contributed to a continued reduction in long-term firm contracted capacity and a shift to short-term firm and interruptible contracts.

Although TransCanada has diversified its natural gas supply sources through recent pipeline acquisitions, many of its North American natural gas pipelines and its transmission infrastructure remain dependent on supply from the WCSB. The WCSB has established natural gas reserves of approximately 61 trillion cubic feet and a reserves-to-production ratio of approximately 11 years at current levels of production. Supply from the WCSB has declined in recent years due to a continued reduction in drilling activity in the basin. The reduced drilling activity is a result of lower prices, higher supply costs, which include increased royalties in Alberta, and competition for capital from other North American gas production basins that have lower exploration costs. Drilling levels in the WCSB are expected to recover in the future, assuming natural gas prices stabilize and finding and development costs become more economical. TransCanada expects there will be excess natural gas pipeline capacity from the WCSB for the foreseeable future as a result of capacity expansions on its natural gas pipelines over the past decade, competition from other pipelines, and significant growth in natural gas consumption within Alberta driven by oilsands and electricity generation requirements.

TransCanada's Alberta System is the major natural gas gathering and transportation system for the WCSB, connecting most of the natural gas processing plants in Alberta to domestic and export markets. Despite reduced overall drilling levels, activity remains robust in certain areas of the WCSB, which has resulted in the need for new transmission infrastructure. Drilling activity has increased in northwestern Alberta, near Grande Prairie, and in northeastern B.C., near Dawson Creek, as producers develop projects to access multi-zone reserves with deeper wells and to access unconventional shale gas utilizing horizontally drilled wells. Recently, shale gas production in B.C. has emerged as a potentially significant natural gas supply source. TransCanada currently forecasts 3.5 Bcf/d total production from the Montney and Horn River shale gas sources by 2020. TransCanada is currently pursuing two major extensions of its Alberta System that would allow emergent unconventional B.C. gas production from the Montney and Horn River shale gas plays to be transported to markets served by TransCanada's pipeline systems.

Demand for natural gas in Eastern Canada and the U.S. Northeast decreased in 2009 largely as a result of a reduction in industrial demand caused by the global recession. However, future demand for natural gas in TransCanada's key eastern markets, which are served by the Canadian Mainline, is expected to increase over time, particularly to meet the expected growth in natural gas-fired power generation. Although there are opportunities to increase market share in Canadian domestic and U.S. export markets, TransCanada faces significant competition in these markets. Consumers in the northeastern U.S. generally have access to an array of natural gas pipeline and supply options. Eastern markets that historically received Canadian supplies only from TransCanada's systems are now able to receive supplies from new natural gas pipelines that source U.S. and Atlantic Canada supplies. In recent years, the Canadian Mainline has experienced reductions in volumes originating at the Alberta border and in Saskatchewan, which have been partially offset by increases in volumes originating at points east of Saskatchewan. These net volume reductions have resulted in an increase in Canadian Mainline tolls that adversely affects its competitive position.

ANR's directly connected natural gas supply is primarily sourced from the Gulf of Mexico and mid-continent U.S. regions, which are also served by competing natural gas pipelines. The Gulf of Mexico region is highly competitive given its extensive natural gas pipeline network. ANR is one of many interstate and intrastate pipelines competing for new and existing production as well as for new supplies from pipelines originating in the mid-continent shale and Rocky Mountain production regions, and from new and existing Gulf Coast LNG regassification terminals. ANR has competition from other natural gas pipelines and storage operations in its primary markets in the U.S. Midwest. In addition to pipeline competition for market and supply, difficult economic conditions have reduced natural gas demand and may put future ANR capacity renewals at risk. As lower natural gas prices reduce drilling activity, the supply growth that has been fuelling the expansion of pipeline infrastructure in the mid-continent could slow down but is still expected to exceed demand requirements in the near term. These factors could negatively affect the value of pipeline capacity as transportation capacity becomes more abundant.

ANR's natural gas storage is primarily contracted on a short-term basis of three to five years. Storage is recontracted based on current market conditions, which may become unfavourable and result in reduced rates and terms.

GTN must compete with other pipelines to access natural gas supplies and markets. Transportation service capacity on GTN provides customers in the U.S. Pacific Northwest, California and Nevada with access to supplies of natural gas primarily from the WCSB. These three markets may also access supplies from other basins. In the Pacific Northwest market, natural gas transported on GTN competes with the Rocky Mountain natural gas supply and with additional Western Canadian supply transported by other pipelines. Historically, natural gas supplies from the WCSB have been competitively priced in relation to supplies from the other regions serving these markets. Recently, low natural gas prices have reduced drilling and production in the WCSB resulting in increased competition for supply which could negatively impact transportation value on GTN. Pacific Gas and Electric Company, GTN's largest customer, has received California Public Utilities Commission approval to commit to capacity on a proposed competing project out of the Rocky Mountain basin to the California border.

Crude Oil Supply, Markets and Competition Alberta is the primary source of crude oil supply for Keystone, producing approximately 79 per cent of the oil in the WCSB. In 2009, the WCSB produced an estimated 2.5 million Bbl/d, comprised of 1.1 million Bbl/d of conventional crude oil and condensate, and 1.4 million Bbl/d of crude oil from Alberta's oilsands. The production of conventional crude oil has been declining but has been offset by increases in production from the Alberta oilsands. The Alberta Energy Resources Conservation Board estimated in its June 2009 report that there are approximately 170 billion barrels of remaining established reserves in the Alberta oilsands.

In June 2009, the Canadian Association of Petroleum Producers forecasted WCSB crude oil supply would increase to 3.3 million Bbl/d by 2015 and to 3.9 million Bbl/d by 2020 from 2.4 million Bbl/d in 2008. In first quarter 2010, crude oil producers announced plans to undertake approximately $8 billion of new oilsands projects, indicating future growth in Alberta oilsands production.

Keystone currently has contracted a significant portion of its capacity. Keystone will compete for spot market throughput with other crude oil pipelines from Alberta and for new long-term contracts as supply from the WCSB increases.

Keystone's markets for crude oil are refiners in the U.S. Midwest and Gulf Coast regions. Keystone will compete with pipelines that deliver WCSB crude oil to these markets through interconnections with other pipelines. Keystone will also compete with U.S. domestically produced crude oil and imported crude oil for markets in the U.S. Midwest and Gulf Coast regions.

Regulatory Financial Risk Regulatory decisions continue to have a significant impact on the financial returns from existing investments in TransCanada's Canadian pipelines and are expected to have a similarly significant impact on financial returns from future investments. Through rate applications and negotiated settlements, TransCanada has been able to improve the financial returns of its Canadian pipeline capital structures.

Regulations and decisions by regulatory bodies, particularly those issued in the U.S. by the FERC, Environmental Protection Agency and Department of Transportation, may have a significant impact on the financial returns from TransCanada's existing investments in U.S. pipelines. TransCanada continually monitors existing and proposed regulations to determine the possible impact on its U.S. pipelines.

Throughput Risk As transportation contracts expire, TransCanada's U.S. natural gas pipelines are expected to become more exposed to the risk of reduced throughput and their revenues are more likely to experience increased variability.

Throughput risk is created by supply and market competition, economic activity, weather variability, natural gas pipeline competition and pricing of alternative fuels.

Execution and Capital Cost Risk Capital costs related to the construction of Keystone are subject to a capital cost risk- and reward-sharing mechanism with TransCanada's customers. This mechanism allows Keystone to adjust its tolls by a factor based on the percentage change in the capital cost of the project. Tolls for the portion of Keystone to Wood River, Patoka and Cushing will be adjusted by a factor equal to 50 per cent of the percentage change in capital cost. Tolls on the expansion to the Gulf Coast would be adjusted by a factor equal to 75 per cent of the percentage change in capital cost.

Refer to the Risk Management and Financial Instruments section of this MD&A for information on additional risks and managing risks in the Pipelines business.

PIPELINES – OUTLOOK

Although demand for natural gas and crude oil has declined and is expected to remain relatively weak in North America in 2010 due to the current economic conditions, the Company expects demand to increase in the long term. TransCanada's Pipelines business will continue to focus on the delivery of natural gas and crude oil to growing markets, connecting new supply and progressing development of new infrastructure to connect natural gas from the north and unconventional supplies such as shale gas, coalbed methane and LNG.

Reduced throughput and greater use of shorter distance transportation contracts are the primary factors contributing to an increase in the Canadian Mainline's toll of approximately 40 per cent in 2010 from 2009. This situation, coupled with the ongoing development and growth of competitive alternative natural gas supply and infrastructure from U.S. shale gas regions, is increasing competitive pressures on the Canadian Mainline. In response, TransCanada has initiated a process to examine the Canadian Mainline's rate design, business model and available services to develop solutions that would result in higher throughput and revenue as well as lower costs and tolls. TransCanada is also pursuing the connection of new sources of U.S. gas supply to the existing Canadian Mainline infrastructure to maintain its current markets and competitive position.

Most of TransCanada's expansion plans in Canadian natural gas transmission are focused on the Alberta System. TransCanada is actively involved in expanding the Alberta System to serve the growing shale gas regions in northeastern B.C. Additional growth opportunities for the Alberta System include the west and central foothills regions of Alberta.

In the U.S., TransCanada expects unconventional production will continue to be developed from shale gas reservoirs in east Texas, northwest Louisiana, Arkansas, southwest Oklahoma and the Appalachian Mountain region. Supplies from coalbed methane and tight gas sands in the Rocky Mountain region are also expected to grow. Additionally, in the medium to long term, some level of incremental supply is anticipated from LNG imports into the U.S., particularly in the summer months. The resulting growth in U.S. supply is expected to provide additional opportunities for TransCanada. In particular, the southwest leg of ANR is expected to continue to remain fully subscribed for the foreseeable future and new transport routes are being developed to move additional Rocky Mountain and shale gas production to mid-western and eastern U.S. markets, including interconnections with ANR. The southeast leg of ANR is well positioned and has capacity to transport additional volumes of unconventional and Rocky Mountain natural gas production as well as LNG.

Producers continue to develop new crude oil supply in Western Canada. Several Alberta oilsands projects recently completed or under construction will begin to produce oil or will increase crude oil production in 2010 and 2011. Oilsands production is forecast to increase to 2.2 million Bbl/d by 2015 from 1.2 million Bbl/d in 2008 and total Western Canada crude oil supply is projected to grow over the same period to 3.3 million Bbl/d from 2.4 million Bbl/d. Most of this growth is in heavy crude oil supply. The primary market for new crude oil production extends from the

U.S. Midwest to the Gulf Coast and contains a large number of refineries that are well equipped to handle Canadian light and heavy crude oil blends. Incremental western Canadian crude oil production is expected to replace declining U.S. imports of crude oil from other countries.

The increase in WCSB crude oil exports from Alberta requires access to new markets, including the Gulf Coast. TransCanada will continue to pursue additional opportunities to move crude oil from Alberta to U.S. markets.

TransCanada will continue to focus on operational excellence and collaboration with all stakeholders to achieve negotiated settlements and provision of services that will increase the value of the Company's business.

Earnings The Company expects continued growth on its Alberta System. TransCanada also anticipates a modest level of investment in its other Canadian natural gas pipelines but expects a continued net decline in the average investment bases of these pipelines due to annual depreciation. A net decline in the average investment base has the effect of reducing year-over-year earnings from these assets. Under the current regulatory model, earnings from Canadian pipelines are not affected by short-term fluctuations in the commodity price of natural gas, changes in throughput volumes or changes in contract levels. In addition, Pipelines' EBITDA is expected to be affected by costs to develop new pipeline projects, including the Alaska pipeline project.

Reduced firm transportation contract volumes due to customer defaults, lower supply available for export from the WCSB and expiry of long-term contracts could have a negative impact on short-term earnings from TransCanada's U.S. natural gas pipelines, unless the available capacity can be recontracted. The ability to recontract available capacity is influenced by prevailing market conditions and competitive factors, including competing natural gas pipelines and supply from other natural gas sources in markets served by TransCanada's U.S. pipelines. EBITDA from Pipelines' foreign operations is also impacted by changes in foreign currency exchange rates.

EBITDA from Keystone is expected to commence in 2010 and continue to increase over the short term until all phases of Keystone are fully operational in 2013. Refer to the Pipelines – Opportunities and Developments section of this MD&A for further information on Keystone's expected EBITDA.

Capital Expenditures Total capital spending for all pipelines in 2009 was $3.9 billion. Capital spending for the wholly owned pipelines in 2010, including Keystone, is expected to be approximately $4.7 billion.

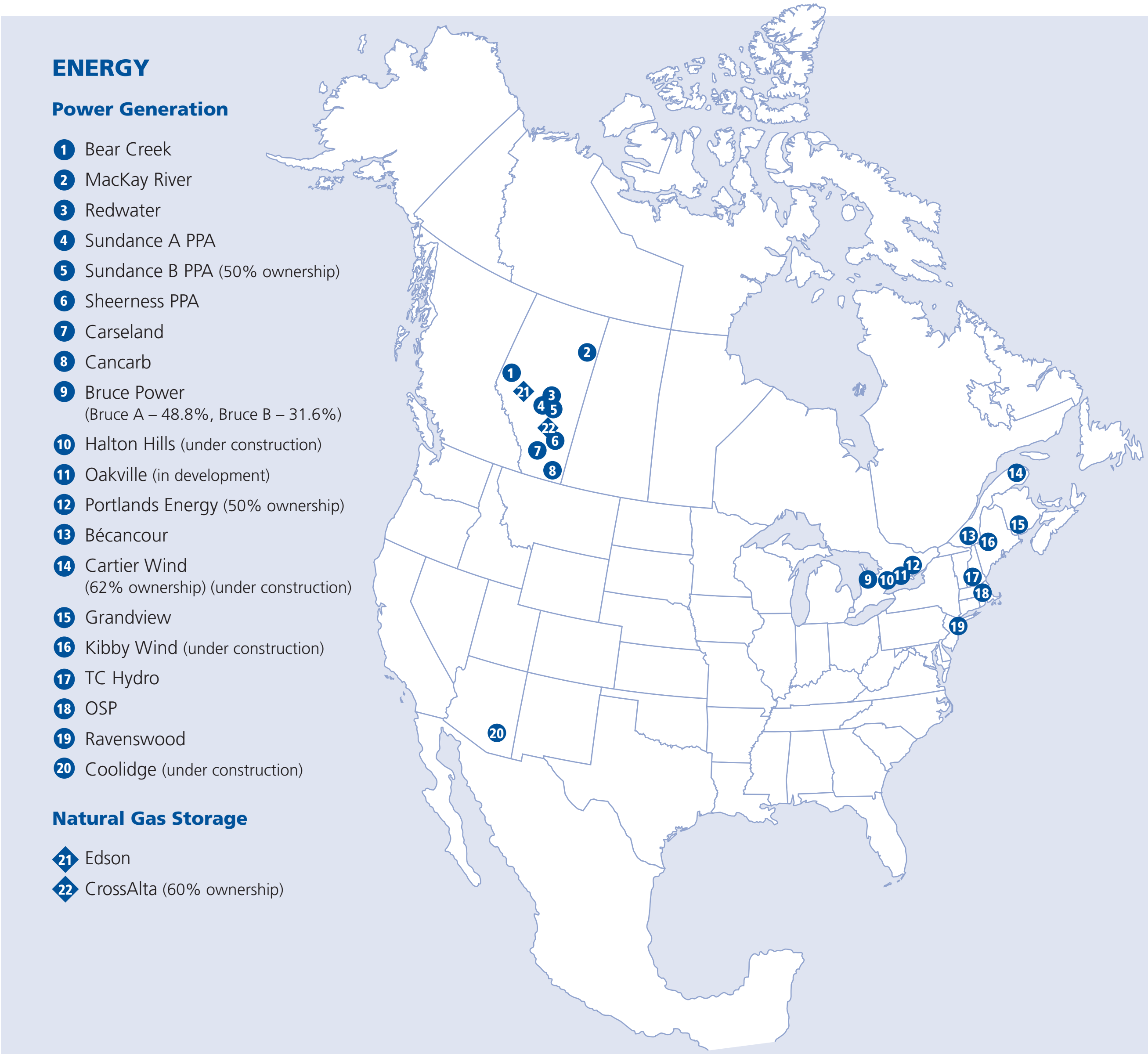
NATURAL GAS THROUGHPUT VOLUMES
(Bcf)

	2009	2008	2007
Canadian Mainline[1]	**2,030**	2,173	2,315
Alberta System[2]	**3,538**	3,800	4,020
ANR[3]	**1,575**	1,619	1,189
Foothills	**1,205**	1,292	1,441
GTN	**797**	783	827
Great Lakes	**727**	784	829
Northern Border	**614**	731	800
Iroquois	**355**	376	394
TQM	**164**	170	207
Ventures LP	**145**	165	178
North Baja	**96**	104	90
Gas Pacifico	**62**	73	71
Tamazunchale	**54**	53	29
Portland	**37**	50	58
Tuscarora	**35**	30	28
TransGas	**28**	26	24

(1) Canadian Mainline's throughput volumes in the above table reflect physical deliveries to domestic and export markets. Throughput volumes reported in previous years reflected contract deliveries. However, customer contracting patterns have changed in recent years making physical deliveries a better measure of system utilization. Canadian Mainline physical receipts originating at the Alberta border and in Saskatchewan in 2009 were 1,579 Bcf (2008 – 1,898 Bcf; 2007 – 2,090 Bcf).

(2) Field receipt volumes for the Alberta System in 2009 were 3,550 Bcf (2008 – 3,843 Bcf; 2007 – 4,047 Bcf).

(3) ANR's results include delivery volumes from its acquisition date of February 22, 2007.



The following Energy assets are owned 100 per cent by TransCanada unless otherwise stated.

BEAR CREEK An 80 MW natural gas-fired cogeneration plant located near Grande Prairie, Alberta.

MACKAY RIVER A 165 MW natural gas-fired cogeneration plant located near Fort McMurray, Alberta.

REDWATER A 40 MW natural gas-fired cogeneration plant located near Redwater, Alberta.

SUNDANCE A&B TransCanada has the rights to 100 per cent of the generating capacity of the 560 MW Sundance A coal-fired power generating facility under a PPA that expires in 2017. TransCanada also has the rights to 50 per cent of the generating capacity of the 706 MW Sundance B facility under a PPA that expires in 2020. The Sundance facilities are located in south-central Alberta.

SHEERNESS TransCanada has the rights to 756 MW of generating capacity from the Sheerness coal-fired plant under a PPA that expires in 2020. The Sheerness plant is located in southeastern Alberta.

CARSELAND An 80 MW natural gas-fired cogeneration plant located near Carseland, Alberta.

CANCARB A 27 MW facility located in Medicine Hat, Alberta fuelled by waste heat from TransCanada's adjacent facility producing thermal carbon black (a natural gas by-product).

BRUCE POWER Bruce Power is a nuclear generating facility located northwest of Toronto, Ontario. TransCanada owns 48.8 per cent of Bruce A, which has four 750 MW reactors. Two of these reactors are currently operating with the remaining two being refurbished. TransCanada owns 31.6 per cent of Bruce B, which has four operating reactors with a combined capacity of approximately 3,200 MW.

HALTON HILLS A 683 MW natural gas-fired power plant under construction near Halton Hills, Ontario.

PORTLANDS ENERGY A 550 MW natural gas-fired, combined-cycle power plant located in Toronto, Ontario. The plant is 50 per cent owned by TransCanada.

OAKVILLE A proposed 900 MW natural gas-fired, combined-cycle power plant under development in Oakville, Ontario.

BÉCANCOUR A 550 MW natural gas-fired cogeneration power plant located near Trois-Rivières, Québec.

CARTIER WIND The 590 MW Cartier Wind farm consists of five wind power projects located in Québec and is 62 per cent owned by TransCanada. Three of the wind farms, Baie-des-Sables, Anse-à-Valleau and Carleton, are in service and have a total generating capacity of 320 MW. Construction activity has begun on the two remaining wind farms, which have a total generating capacity of 270 MW.

GRANDVIEW A 90 MW natural gas-fired cogeneration power plant located in Saint John, New Brunswick.

KIBBY WIND A 132 MW wind power project located in Kibby and Skinner Townships in Maine. The first phase of the project is operating and has a generating capacity of 66 MW. Phase two is under construction and will have a generating capacity of 66 MW.

TC HYDRO TC Hydro has a total generating capacity of 583 MW and is comprised of 13 hydroelectric facilities, including stations and associated dams and reservoirs, on the Connecticut and Deerfield rivers in New Hampshire, Vermont and Massachusetts.

OSP A 560 MW natural gas-fired, combined-cycle facility located in Burrillville, Rhode Island.

RAVENSWOOD A 2,480 MW multiple unit generating facility located in Queens, New York, employing dual-fuel capable steam turbine, combined-cycle and combustion turbine technology.

COOLIDGE A 575 MW simple-cycle, natural gas-fired peaking power facility under construction in Coolidge, Arizona.

EDSON An underground natural gas storage facility connected to the Alberta System near Edson, Alberta. Edson's central processing system is capable of maximum injection and withdrawal rates of 725 mmcf/d of natural gas, and has a working storage capacity of approximately 50 Bcf.

CROSSALTA A 68 Bcf underground natural gas storage facility connected to the Alberta System near Crossfield, Alberta. CrossAlta's central processing system is capable of maximum injection and withdrawal rates of 550 mmcf/d of natural gas. TransCanada owns 60 per cent of CrossAlta.

ENERGY – HIGHLIGHTS

Energy's comparable EBITDA was $1.1 billion in 2009, a decrease of $0.1 billion from $1.2 billion in 2008.

- In 2009, the Company invested $1.5 billion in Energy capital projects, including:
  - The 550 MW Portlands Energy facility, which was fully commissioned in April 2009 and completed under budget; and
  - the first phase of the Kibby Wind power project, which was placed in service in October 2009, six weeks ahead of schedule, and was also completed under budget.
- In July 2009, Bruce Power and the OPA amended certain terms and conditions included in the Bruce Power Refurbishment Implementation Agreement. The amendments are consistent with the intent of the contract, originally signed in 2005, and recognize the significant changes in Ontario's electricity market.
- The Bruce A Unit 1 and 2 refurbishment and restart project continues. Unit 2 is expected to return to service in mid-2011 with Unit 1 to follow approximately four months later. TransCanada expects its share of the capital costs to complete this project to be approximately $2 billion.
- Approximately 3,100 MW of generation capacity was under construction and in development at December 31, 2009, at an anticipated capital cost of approximately $7 billion.

POWER PLANTS – NOMINAL GENERATING CAPACITY AND FUEL TYPE

	MW	Fuel Type
Canadian Power		
Western Power		
Sheerness	756	Coal
Coolidge[1]	575	Natural gas
Sundance A	560	Coal
Sundance B[2]	353	Coal
MacKay River	165	Natural gas
Carseland	80	Natural gas
Bear Creek	80	Natural gas
Redwater	40	Natural gas
Cancarb	27	Natural gas
	2,636	
Eastern Power		
Oakville[1]	900	Natural gas
Halton Hills[1]	683	Natural gas
Bécancour	550	Natural gas
Cartier Wind[1][3]	365	Wind
Portlands Energy[4]	275	Natural gas
Grandview	90	Natural gas
	2,863	
Bruce[5]	2,480	Nuclear
	7,979	
U.S. Power		
Ravenswood	2,480	Natural gas/oil
TC Hydro	583	Hydro
OSP	560	Natural gas
Kibby Wind[1]	132	Wind
	3,755	
Total nominal generating capacity[1]	11,734	

(1) Coolidge, Halton Hills, two Cartier Wind farms (168 MW) and phase two of Kibby Wind (66 MW) are currently under construction. Oakville is currently under development.

(2) Represents TransCanada's 50 per cent share of the Sundance B power plant output.

(3) Represents TransCanada's 62 per cent share of this total 590 MW project.

(4) Represents TransCanada's 50 per cent share of this 550 MW facility.

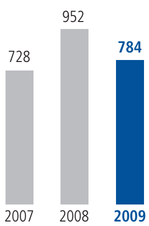
(5) Represents TransCanada's 48.8 per cent proportionate interest in Bruce A and 31.6 per cent proportionate interest in Bruce B.

ENERGY – RESULTS
Year ended December 31 *(millions of dollars)*

	2009	2008	2007
Canadian Power			
Western Power	**279**	510	385
Eastern Power	**220**	147	120
Bruce Power	**352**	275	240
General, administrative and support costs	**(39)**	(39)	(35)
Canadian Power Comparable EBITDA(1)	**812**	893	710
U.S. Power			
Northeast Power	**237**	272	184
General, administrative and support costs	**(45)**	(41)	(32)
U.S. Power Comparable EBITDA(1)	**192**	231	152
Natural Gas Storage			
Alberta Storage	**173**	152	151
General, administrative and support costs	**(9)**	(14)	(14)
Natural Gas Storage Comparable EBITDA(1)	**164**	138	137
Business Development Comparable EBITDA(1)	**(37)**	(52)	(55)
Energy Comparable EBITDA(1)	**1,131**	1,210	944
Depreciation and amortization	**(347)**	(258)	(216)
Energy Comparable EBIT(1)	**784**	952	728
Specific items:			
Fair value adjustments of natural gas inventory in storage and forward contracts	**1**	–	10
Writedown of Broadwater LNG project costs	**–**	(41)	–
Gain on sale of land	**–**	–	16
Energy EBIT(1)	**785**	911	754

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of comparable EBITDA, comparable EBIT and EBIT.

Energy Comparable EBIT
(millions of dollars)



Energy's comparable EBIT was $784 million in 2009 compared to $952 million in 2008. Comparable EBIT excluded net unrealized gains of $1 million and nil in 2009 and 2008, respectively, resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Comparable EBIT in 2008 excluded the $41 million writedown of costs previously capitalized for the Broadwater LNG project.

Energy's comparable EBIT in 2008 of $952 million increased $224 million compared to $728 million in 2007. Comparable EBIT in 2007 excluded a $16 million gain on sale of land and $10 million of net unrealized gains resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

ENERGY – FINANCIAL ANALYSIS

Western Power As at December 31, 2009, Western Power owned or had the rights to approximately 2,600 MW of power supply in Alberta and the Western U.S. from its three long-term PPAs, five natural gas-fired cogeneration facilities and a simple-cycle, natural gas peaking facility under construction in Arizona. The current operating power supply portfolio of Western Power in Alberta comprises approximately 1,700 MW of low-cost, base-load coal-fired generation supply through the three long-term PPAs and approximately 400 MW of natural gas-fired cogeneration assets. This supply portfolio includes some of the lowest cost, most competitive generation in the Alberta market area. The Sheerness and Sundance B PPAs expire in 2020, while the Sundance A PPA expires in 2017. Plant operations in Alberta consist of five natural gas-fired cogeneration power plants ranging from 27 MW to 165 MW per facility. A portion of the expected output from these facilities is sold under long-term contracts and the remaining output is subject to fluctuations in the price of power and natural gas.

Western Power relies on its two integrated functions, marketing and plant operations, to generate earnings. The marketing function, based in Calgary, Alberta, purchases and resells electricity sourced through the PPAs, markets uncommitted volumes from the cogeneration facilities, and purchases and resells power and natural gas to maximize the value of the cogeneration facilities. The marketing function is critical for optimizing Energy's return from its portfolio of power supply and managing risks associated with uncontracted volumes. A portion of Energy's power is sold into the spot market to ensure supply in case of unexpected plant outages. The overall amount of spot market volumes is dependent upon the ability to transact in forward sales markets at acceptable contract terms. This approach to portfolio management helps to minimize costs in situations where TransCanada would otherwise have to purchase electricity in the open market to fulfil its contractual sales obligations. To reduce exposure to spot market prices on uncontracted volumes, as at December 31, 2009, Western Power had fixed-price power sales contracts to sell approximately 8,400 gigawatt hours (GWh) in 2010 and 6,000 GWh in 2011.

Eastern Power Eastern Power owns approximately 2,900 MW of power generation capacity, including facilities under construction or in the development phase. Eastern Power's current operating power generation assets are Bécancour, three Cartier Wind farms, Portlands Energy and Grandview.

Bécancour's entire power output is supplied to Hydro-Québec under a 20 year power purchase contract expiring in 2026. Steam from this facility is sold to an industrial customer for use in commercial processes. Electricity generation at the Bécancour power plant has been temporarily suspended since January 2008 due to an agreement entered into with Hydro-Québec. Under the agreement TransCanada continues to receive payments similar to those that would have been received under the normal course of operation. The suspension of the Bécancour power facility is discussed further in the Energy – Opportunities and Developments section of this MD&A.

Cartier Wind's three wind farms, Carleton, Anse-à-Valleau, and Baie-des-Sables, were placed into service in November 2008, November 2007 and November 2006, respectively. Output from these wind farms is supplied to Hydro-Québec under 20 year power purchase contracts.

Portlands Energy was placed into service in April 2009. This facility provides power under a 20 year Accelerated Clean Energy Supply contract with the OPA.

Grandview is located on the site of the Irving oil refinery in Saint John, New Brunswick. Irving is under a 20 year tolling arrangement, which expires in 2025, to supply fuel for the plant and to contract 100 per cent of the 90 MW plant's heat and electricity output.

Eastern Power is focused on selling power under long-term contracts. In 2007, 2008 and 2009, all of Eastern Power sales volumes were sold under contract and are expected to continue to be 100 per cent sold under contract for 2010 and 2011.

Western and Eastern Canadian Power Comparable EBITDA(1)(2)
Year ended December 31 *(millions of dollars)*

	2009	2008	2007
Revenues			
Western power	**788**	1,140	1,045
Eastern power	**281**	175	400
Other(3)	**184**	186	89
	1,253	1,501	1,534
Commodity purchases resold			
Western power	**(451)**	(517)	(550)
Eastern power	**–**	–	(2)
Other(4)	**(124)**	(112)	(65)
	(575)	(629)	(617)
Plant operating costs and other	**(179)**	(215)	(412)
General, administrative and support costs	**(39)**	(39)	(35)
Comparable EBITDA(1)	**460**	618	470

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of comparable EBITDA.

(2) Includes Portlands Energy, Carleton and Anse-à-Valleau effective April 2009, November 2008 and November 2007, respectively.

(3) Other revenue includes sales of natural gas, sulphur sales in 2008 and thermal carbon black.

(4) Other commodity purchases resold includes the cost of natural gas sold.

Western and Eastern Canadian Power Operating Statistics[(1)]
Year ended December 31

	2009	2008	2007
Sales Volumes (GWh)			
Supply			
Generation			
Western Power	**2,334**	2,322	2,154
Eastern Power	**1,550**	1,069	5,200
Purchased			
Sundance A & B and Sheerness PPAs	**10,603**	12,368	12,199
Other purchases	**529**	970	1,710
	15,016	16,729	21,263
Sales			
Contracted			
Western Power	**9,944**	11,284	11,998
Eastern Power	**1,588**	1,232	5,477
Spot			
Western Power	**3,484**	4,213	3,788
	15,016	16,729	21,263
Plant Availability[(2)]			
Western Power[(3)]	**93%**	87%	90%
Eastern Power	**97%**	97%	97%

(1) Includes Portlands Energy, Carleton and Anse-à-Valleau effective April 2009, November 2008, November 2007, respectively. Bécancour is included only in 2007 due to the agreement with Hydro-Québec to temporarily suspend electricity generation in 2008 and 2009.

(2) Plant availability represents the percentage of time in a year that the plant is available to generate power regardless of whether it is running.

(3) Excludes facilities that provide power to TransCanada under PPAs.

Western Power's comparable EBITDA of $279 million in 2009 decreased $231 million compared to $510 million in 2008. The decrease was primarily due to a decline in earnings from the Alberta power portfolio resulting from lower overall realized prices on reduced volumes of power sold. In addition, Western Power's EBITDA in 2008 included $23 million related to sulphur sales.

Lower overall realized power prices and lower sales volumes resulted in a decrease of $352 million in Western Power's power revenues in 2009 compared to 2008. Average spot market power prices in Alberta decreased 47 per cent, or $42 per megawatt hour (MWh) in 2009 compared to 2008 and Western Power's sales volumes decreased 13 per cent in 2009 from 2008 primarily as a result of reduced dispatch of the Alberta PPAs. The reduction in power prices and sales volumes both reflected reduced demand for electricity in Alberta as a result of the North American economic downturn. Commodity purchases resold of $451 million in 2009 decreased $66 million compared to 2008 due to a reduction in volumes purchased and the expiry of certain retail contracts. Approximately 26 per cent of Western Power's sales volumes were sold in the spot market in 2009 compared to 27 per cent in 2008.

Eastern Power's comparable EBITDA of $220 million in 2009 increased $73 million compared to $147 million in 2008. The increase was primarily due to incremental earnings from Portlands Energy, which was placed in service in April 2009, and the Carleton wind farm at Cartier Wind, which went into service in November 2008, as well as higher contracted revenue from the Bécancour facility. Eastern Power's power revenues increased $106 million primarily due to the incremental revenues from Portlands Energy and the Carleton wind farm.

Other revenues and other commodity purchases resold were $184 million and $124 million, respectively, in 2009 compared to $186 million and $112 million, respectively, in 2008. These changes reflected an increase in the quantity of natural gas being resold in Eastern Power. Increased sales of natural gas in other revenues in 2009 were more than offset by the sale of sulphur in 2008.

Plant operating costs and other, which includes fuel gas consumed in power generation, of $179 million in 2009 decreased $36 million from 2008 primarily due to lower prices for natural gas in Western Power, partially offset by incremental fuel consumed at Portlands Energy.

Western Power's comparable EBITDA was $510 million in 2008, an increase of $125 million from $385 million in 2007. The increase was primarily due to increased margins from a combination of higher overall realized power prices on uncontracted volumes of power sold and a $23 million increase from sales of sulphur at significantly higher prices in 2008. In 2008, the Company sold the remainder of its sulphur stock pile, which it had been selling in modest quantities on a break-even basis since 2005.

Western Power's power revenues increased $95 million in 2008 compared to 2007 primarily due to the higher overall power sales prices. Commodity purchases resold decreased $33 million in 2008 compared to 2007 primarily due to a decrease in volumes purchased and the expiry of certain retail contracts. Purchased power volumes in 2008 decreased from 2007 primarily due to the expiry of certain retail contracts, partially offset by increased utilization from the Alberta PPAs. Approximately 27 per cent of power sales volumes were sold in the spot market in 2008 compared to 24 per cent in 2007.

Eastern Power's comparable EBITDA of $147 million in 2008 increased $27 million compared to 2007 as a result of higher contracted earnings from the Bécancour facility, incremental earnings from the first full year of operations from the Anse-à-Valleau wind farm and the start up of the Carleton wind farm in 2008.

The agreement to temporarily suspend generation at the Bécancour facility beginning January 2008 resulted in decreases to Eastern Power's power revenues, generation volumes and contracted sales as well as plant operating costs and other in 2008 compared to 2007.

Decreases in plant operating costs and other in 2008 compared to 2007 due to the temporary suspension of the Bécancour facility were partially offset by higher volumes of gas purchased at higher prices in Western Power.

Western Power's plants operated with an average availability of approximately 93 per cent in 2009 compared to 87 per cent in 2008, primarily due to the return to service of the Cancarb facility in April 2009. Western Power's overall plant availability was negatively affected from late 2007 until April 2009 by an outage at the Cancarb power plant. Eastern Power achieved plant availability of 97 per cent in 2009, consistent with 2008 and 2007. Bécancour, which had an availability of 97 per cent in 2007, is not included in Eastern Power's 2009 and 2008 measurement as power generation from the plant was suspended throughout 2008 and 2009.

Bruce Power Bruce Power is a nuclear power generation facility located northwest of Toronto, Ontario and is comprised of Bruce A and Bruce B. Bruce A has four 750 MW reactors, of which two are currently operating and two are being refurbished. One unit is expected to be restarted in mid-2011 and the other unit is expected to be restarted approximately four months thereafter. Bruce B has four operating reactors with a combined capacity of 3,200 MW. As at December 31, 2009, TransCanada and BPC Generation Infrastructure Trust (BPC), a trust established by the Ontario Municipal Employees Retirement System (OMERS), each owned a 48.8 per cent interest in Bruce A (2008 – 48.9 per cent; 2007 – 48.7 per cent). The remaining 2.4 per cent interest in Bruce A is owned by the Power Workers' Union Trust (PWU), the Society of Energy Professionals Trust (SEP) and Bruce Power Employee Investment Trust. The Bruce A partnership subleases Bruce A Units 1 to 4 from the Bruce B partnership. TransCanada, OMERS and Cameco Corporation each own 31.6 per cent of Bruce B, which consists of Units 5 to 8 and the supporting site infrastructure. The remaining interest in Bruce B is owned by PWU and SEP.

The following Bruce Power financial results reflect TransCanada's proportionate share of the eight Bruce Power units, six of which were operating:

Bruce Power Results (TransCanada's proportionate share) Year ended December 31 *(millions of dollars unless otherwise indicated)*	**2009**	2008	2007
Revenues[1][2]	**883**	785	847
Operating expenses[2]	**(531)**	(510)	(607)
Comparable EBITDA[3]	**352**	275	240
Bruce A Comparable EBITDA[3]	**48**	78	38
Bruce B Comparable EBITDA[3]	**304**	197	202
Comparable EBITDA[3]	**352**	275	240
Bruce Power – Other Information			
Plant availability			
Bruce A	**78%**	82%	78%
Bruce B	**91%**	87%	89%
Combined Bruce Power	**87%**	86%	86%
Planned outage days			
Bruce A	**56**	91	121
Bruce B	**45**	100	93
Unplanned outage days			
Bruce A	**82**	27	17
Bruce B	**47**	65	32
Sales volumes (GWh)			
Bruce A	**4,894**	5,159	4,959
Bruce B	**7,767**	7,799	7,992
	12,661	12,958	12,951
Results per MWh			
Bruce A power revenues	**$64**	$62	$59
Bruce B power revenues[4]	**$64**	$57	$52
Combined Bruce Power revenues	**$64**	$59	$55
Percentage of output sold to spot market[5]	**43%**	33%	62%

(1) Revenues include Bruce A fuel cost recoveries of $34 million in 2009 (2008 – $30 million; 2007 – $17 million). Revenues also include Bruce B unrealized gains of $5 million as a result of changes in the fair value of held-for-trading derivatives in 2009 (2008 – $2 million losses; 2007 – $15 million gains).

(2) Includes adjustments to eliminate the effects of inter-partnership transactions between Bruce A and Bruce B.

(3) Refer to the Non-GAAP Measures section in this MD&A for further discussion of comparable EBITDA.

(4) Includes revenues received under the floor price mechanism, from contract settlements and from deemed generation, and the associated volumes.

(5) All of Bruce B's output is covered by the floor price mechanism, including volumes sold to the spot market.

TransCanada's proportionate share of Bruce Power's comparable EBITDA increased $77 million to $352 million in 2009 compared to 2008 primarily due to higher realized prices and reduced annual lease expense, partially offset by lower volumes and higher operating expenses for Bruce A.

TransCanada's proportionate share of Bruce A's comparable EBITDA decreased $30 million to $48 million in 2009 compared to 2008 as a result of lower volumes and higher operating expenses due to an increase in outage days, partially offset by higher contracted prices for output.

TransCanada's proportionate share of Bruce B's comparable EBITDA increased $107 million to $304 million in 2009 compared to 2008 primarily due to higher realized prices resulting from the recognition of payments received pursuant to the floor price mechanism in Bruce B's contract with the OPA and a reduction in annual lease expense. Provisions in a lease agreement with Ontario Power Generation allowed for a reduction in annual lease expense as the annual average Ontario spot price for electricity was less than $30 per MWh. The annual average Ontario spot price was $29.52 per MWh in 2009 compared to 48.83 per MWh in 2008.

Amounts received under the floor price mechanism in any calendar year are subject to repayment if the annual average spot price exceeds the annual average floor price. In 2009, the annual average spot price did not exceed the annual average floor price, therefore, no amounts recorded in revenue in 2009 will be repaid. Bruce B did not recognize into revenue any of the support payments received under the floor price mechanism in 2007 or 2008 as the annual average spot price exceeded the annual average floor price.

TransCanada's proportionate share of Bruce Power's comparable EBITDA in 2008 increased $35 million to $275 million compared to 2007 as a result of higher realized prices and increased volumes associated with a decrease in outage days at Bruce A in 2008.

TransCanada's proportionate share of Bruce Power's generation in 2009 decreased to 12,661 GWh compared to 12,958 GWh in 2008, partially due to periods in 2009 when the Independent Electricity System Operator (IESO) curtailed certain units at Bruce Power to address surplus base load generation in Ontario. During these unit curtailments by the IESO, Bruce Power received deemed generation payments at OPA contract prices. Including deemed generation, the combined average availability of Bruce A and Bruce B was 87 per cent in 2009 compared to 86 per cent in 2008. TransCanada's proportionate share of Bruce Power's generation in 2008 was consistent with 2007.

The overall plant availability percentage in 2010 is expected to be in the mid-80s for the two operating Bruce A units and in the high 80s for the four Bruce B units. An approximate ten week maintenance outage of Bruce A Unit 3 is scheduled to begin in late February 2010. Maintenance outages of approximately eight weeks are scheduled to begin in May 2010 for Bruce B Unit 6 and mid-October 2010 for Bruce B Unit 5.

Bruce A

Under a contract with the OPA, all of the output from Bruce A is effectively sold at a fixed price per MWh, adjusted for inflation annually each April 1. In addition, fuel costs are recovered from the OPA. In accordance with a 2007 contract amendment, effective April 1, 2009, the fixed price for output from Bruce A was $64.45 per MWh.

Bruce A Fixed Price

	per MWh
April 1, 2009 – March 31, 2010	$64.45
April 1, 2008 – March 31, 2009	$63.00
April 1, 2007 – March 31, 2008	$59.69

Bruce B

As part of Bruce Power's contract with the OPA, all output from Bruce B Units 5 to 8 are subject to a floor price adjusted annually for inflation on April 1.

Bruce B Floor Price

	per MWh
April 1, 2009 – March 31, 2010	$48.76
April 1, 2008 – March 31, 2009	$47.66
April 1, 2007 – March 31, 2008	$46.82

Payments received pursuant to the Bruce B floor price mechanism were previously subject to a recapture payment dependent on annual spot prices over the entire term of the contract. In July 2009, the contract with the OPA was amended making payments received pursuant to the floor price mechanism subject to recapture payments dependent on annual spot prices only within each calendar year.

Bruce B enters into fixed-price contracts under which it receives the difference between the contract price and spot price. As a result, Bruce B's 2009 realized price of $64 per MWh reflects revenues recognized from both the floor price mechanism and contract sales, compared to $57 per MWh and $52 per MWh in 2008 and 2007, respectively. As at December 31, 2009, Bruce B had entered into fixed-price contracts to sell forward approximately 2,100 GWh for 2010 and 500 GWh for 2011, representing TransCanada's proportionate share.

U.S. Power U.S. Power owns approximately 3,800 MW of power generation capacity, including facilities under construction. U.S. Power's current operating power generation assets are Ravenswood, TC Hydro, OSP, and phase one of Kibby Wind. Ravenswood, located in Queens, New York and acquired in August 2008, is a 2,480 MW natural gas and oil-fired generating facility consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology with the capacity to serve approximately 21 per cent of the overall peak load in New York City. The TC Hydro assets include 13 hydroelectric stations housing a total of 39 hydroelectric generating units in New Hampshire, Vermont and Massachusetts with total generating capacity of 583 MW. OSP, a 560 MW natural gas-fired combined-cycle facility, is the largest power plant in Rhode Island and phase one of Kibby Wind is a 66 MW wind farm located in Maine.

U.S. Power conducts its business primarily in the deregulated New England and New York power markets through its wholly owned subsidiary, TCPM, located in Westborough, Massachusetts. TCPM focuses on selling power under short- and long-term contracts to wholesale, commercial and industrial customers while managing a portfolio of power supplies sourced from both its own generation and wholesale power purchases. Power is purchased to satisfy a significant portion of TCPM's retail and wholesale power sales commitments, mitigating its exposure to fluctuations in spot market prices and effectively locking in a positive margin. Power generation is managed by entering into contracts to sell a portion of power forecasted to be generated. Corresponding contracts are entered into simultaneously to purchase the fuel required to reduce exposure to market price volatility and lock in positive margins. In 2009, TCPM continued to expand its marketing presence and customer base in the New England and New York markets.

The New England Power Pool relies on a Forward Capacity Market (FCM) to promote investment in new and existing power resources needed to meet growing consumer demand and maintain a reliable power system. FCM payments began in late 2006 and operated on a transition basis from 2007 to 2009. During this period, OSP and TC Hydro received capacity transition payments under this mechanism as specified in the FERC-approved FCM settlement. Beginning in June 2010, the price paid for capacity will be determined by annual competitive FCM auctions, which are held three years in advance of the capacity year in question. Future auction results will be affected by actual versus projected demand, the pace of progress in developing new qualifying resources that bid into the auctions and other factors.

The New York Independent System Operator (NYISO) relies on a locational capacity market intended to promote investment in new and existing power resources needed to meet growing consumer demand and maintain a reliable power system. At present, a series of voluntary forward auctions and a mandatory spot demand curve price setting process are used to determine the price paid to capacity suppliers. There are two annual six-month strip forward auctions and 12 monthly forward auctions in which buyer and seller participation is optional. All remaining available capacity is required to participate in a monthly spot auction in the final week prior to the capacity month. The spot auction clears at a price based on a downward sloping demand curve, the parameters of which are determined by the NYISO and approved by the FERC. There are separate demand curves for each of three defined capacity zones: Long Island, New York City, and Rest of State. The Ravenswood capacity is located in the New York City capacity zone.

U.S. Power Comparable EBITDA[1][2]

Year ended December 31 *(millions of dollars)*

	2009	2008	2007
Revenues			
Power	**1,118**	938	1,035
Capacity	**190**	85	46
Other[3][4]	**509**	350	239
	1,817	1,373	1,320
Commodity purchases resold			
Power	**(544)**	(519)	(753)
Other[5]	**(391)**	(324)	(208)
	(935)	(843)	(961)
Plant operating costs and other[4]	**(645)**	(258)	(175)
General, administrative and support costs	**(45)**	(41)	(32)
Comparable EBITDA[1]	**192**	231	152

(1) Refer to the Non-GAAP Measures section of this MD&A for further discussion of comparable EBITDA.

(2) Includes phase one of Kibby Wind and Ravenswood as of October 2009 and August 2008, respectively.

(3) Includes sales of natural gas.

(4) Includes Ravenswood revenues and costs related to a third-party service agreement.

(5) Other commodity purchases resold includes the cost of natural gas sold.

U.S. Power Operating Statistics[1]

Year ended December 31

	2009	2008	2007
Sales Volumes (GWh)			
Supply			
Generation	**5,993**	3,974	2,895
Purchased	**5,310**	6,020	6,709
	11,303	9,994	9,604
Sales			
Contracted	**10,264**	9,758	9,028
Spot	**1,039**	236	576
	11,303	9,994	9,604
Plant Availability[2]	**79%**	75%	95%

(1) Includes phase one of Kibby Wind and Ravenswood as of October 2009 and August 2008, respectively.

(2) Plant availability represents the percentage of time in a year that the plant is available to generate power regardless of whether it is running.

U.S. Power's comparable EBITDA was $192 million in 2009, $39 million lower than the $231 million earned in 2008. The decrease was primarily due to reduced power prices and lower margins realized on generation volumes in New England, partially offset by forward hedging activities. Lower realized prices were a result of the economic downturn coupled with unseasonably mild weather. These decreases were partially offset by incremental revenue realized on contract sales at higher than average spot market prices in New England. The reduction in New England EBITDA was partially offset by incremental EBITDA from a full year of operations at the Ravenswood facility, which was acquired in August 2008, and the positive impact of a stronger U.S. dollar in 2009. Ravenswood results in 2009 were impacted by spot prices, which were 52 per cent lower than in 2008, and reduced power demand.

U.S. Power's power revenues of $1,118 million in 2009, increased $180 million from $938 million in 2008 primarily due to incremental revenues from the Ravenswood facility, the positive impact of a stronger U.S. dollar and an increase in financial contract sales, partially offset by lower volumes of power sold at lower prices in New England. Capacity revenue of $190 million in 2009 increased $105 million from $85 million in 2008 primarily due to incremental capacity revenue from Ravenswood, which is earned based on plant availability regardless of whether the plant is generating electricity.

Other revenues increased $159 million in 2009 compared to 2008 as a result of higher volumes of natural gas sold, revenues earned from the third-party service agreement at Ravenswood and the positive impact of a stronger U.S. dollar.

Power commodity purchases resold increased $25 million in 2009 compared to 2008 primarily due to the incremental impact of financial contract purchases in New England and the impact of a stronger U.S. dollar in 2009. These increases were partially offset by lower volumes of power purchased for resale at lower prices to commercial and industrial customers in New England.

Other commodity purchases resold increased $67 million in 2009 compared to 2008 primarily due to higher volumes of unutilized natural gas purchased for plant fuel and resold as well as the impact of a stronger U.S. dollar, partially offset by a decrease in natural gas prices.

Plant operating costs and other increased $387 million in 2009 compared to 2008 due to a full year of operations and costs related to a third-party service agreement at Ravenswood, as well as the impact of a stronger U.S. dollar.

Comparable EBITDA was $231 million in 2008, $79 million higher than the $152 million earned in 2007. The increase was primarily due to increased water flows from the TC Hydro generation assets and higher realized prices on sales to commercial and industrial customers in New England. On December 31, 2008, Ravenswood fulfilled its obligations under a tolling agreement with a third party that was in place at the time of its acquisition. Beginning in 2009, TCPM has managed the marketing output of the Ravenswood plant in a manner consistent with its other U.S. Northeast portfolio of assets.

U.S. Power achieved plant availability of 79 per cent in 2009 compared to 75 per cent in 2008 primarily due to the return to service of Ravenswood Unit 30 in May 2009 following an unplanned outage. Plant availability in 2008 was 20 per cent lower than in 2007 as a result of outages experienced at Ravenswood throughout fourth quarter 2008.

In 2009, nine per cent of power sales volumes were sold into the spot market compared to two per cent in 2008. At December 31, 2009, U.S. Power had fixed price sales contracts to sell forward approximately 10,300 GWh in 2010 and 5,400 GWh in 2011, including financial contracts to economically hedge the price of forecasted power generation. Certain contracted volumes are dependent on customer usage levels. Actual amounts contracted in future periods will depend on market liquidity and other factors. Power has been purchased to satisfy a portion of these sales requirements, reducing exposure to volatility in spot prices and effectively locking in a margin.

Natural Gas Storage TransCanada owns or has rights to 129 Bcf of non-regulated natural gas storage capacity in Alberta, including a 60 per cent ownership interest in CrossAlta, an independently operated storage facility. TransCanada also has contracts for long-term, Alberta-based storage capacity from a third party, which expire in 2030, subject to early termination rights in 2015.

Natural Gas Storage Capacity

	Working Gas Storage Capacity (Bcf)	Maximum Injection/ Withdrawal Capacity (mmcf/d)
Edson	50	725
CrossAlta[(1)]	41	550
Third-party storage	38	630
	129	1,905

(1) Represents TransCanada's 60 per cent ownership interest in CrossAlta. Working gas storage capacity can vary due to the amount of base gas in the facility.

The Company's natural gas storage capability helps balance seasonal and short-term supply and demand, and adds flexibility to the delivery of natural gas to markets in Alberta and the rest of North America. The increasing seasonal imbalance in North American natural gas supply and demand has increased natural gas price volatility and the demand for storage services. Alberta-based storage will continue to serve market needs and could play an important role as additional gas supplies are connected to North American markets. Energy's natural gas storage business operates independently from TransCanada's regulated natural gas transmission business and from ANR's regulated storage business, which is included in TransCanada's Pipelines segment.

TransCanada manages the exposure of its non-regulated natural gas storage assets to seasonal natural gas price spreads by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales.

Market volatility creates arbitrage opportunities and TransCanada's storage facilities provide customers with the ability to capture value from short-term price movements. At December 31, 2009, TransCanada had contracted approximately 75 per cent of the total 129 Bcf of working gas storage capacity in 2010 and 51 per cent of storage capacity in 2011. Earnings from third-party storage capacity contracts are recognized over the terms of the contracts.

Proprietary natural gas storage transactions are comprised of a forward purchase of natural gas to be injected into storage and a simultaneous forward sale of natural gas for withdrawal at a later period, typically during the winter withdrawal season. By matching purchase and sales volumes on a back-to-back basis, TransCanada locks in future positive margins, effectively eliminating its exposure to natural gas seasonal price spreads.

These forward natural gas contracts provide highly effective economic hedges but do not meet the specific criteria for hedge accounting and, therefore, are recorded at their fair value based on the forward market prices for the contracted month of delivery. Changes in the fair value of these contracts are recorded in revenues. TransCanada records its proprietary natural gas inventory in storage at its fair value using a weighted average of forward prices for natural gas for the following four months, less selling costs. Changes in the fair value of inventory are recorded in revenues. Changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sales contracts are excluded in determining comparable earnings, as they are not representative of amounts that will be realized on settlement.

Natural Gas Storage's comparable EBITDA in 2009 was $164 million compared to $138 million in 2008. The $26 million increase in EBITDA was primarily due to increased third-party storage revenues as a result of higher realized seasonal natural gas price spreads. Natural Gas Storage's comparable EBITDA was $138 million in 2008 which was consistent with 2007.

Business Development Business development comparable EBITDA losses in 2009 decreased $15 million compared to 2008 primarily due to the timing of expenses on certain key projects.

Depreciation and Amortization Depreciation and amortization of $347 million in 2009 increased $89 million compared to 2008 primarily due to a full year of operations at Ravenswood, capital additions at Bruce Power and the start-up of Portlands Energy and the Carleton wind farm in April 2009 and November 2008, respectively.

ENERGY – OPPORTUNITIES AND DEVELOPMENTS

Ravenswood From the time of its acquisition to December 31, 2008, Ravenswood operated under a tolling arrangement under which all energy generated from the facility was provided to a third party for a fixed operating fee. In January 2009, Ravenswood commenced earning revenues from the sale of energy generated from the facility into the New York market. TCPM manages the marketing of output from Ravenswood.

Subsequent to closing the acquisition of Ravenswood, TransCanada experienced a forced outage event related to Ravenswood's 972 MW Unit 30. The unit returned to service in May 2009. The Company continues to work with its insurers with respect to claims for both the physical damage and business interruption losses associated with the outage. No amounts have been accrued for claims with respect to business interruption losses.

Bruce Power Under a long-term agreement reached in 2005 between Bruce Power and the OPA, Bruce A committed to refurbish and restart the currently idle Units 1 and 2, extend the operating life of Unit 3 and replace the steam generators on Unit 4. An amendment to the agreement in 2007 provided for a full refurbishment of Unit 4, which will extend the expected operating life of the unit.

In 2008, Bruce Power completed a review of the operating life estimates for Units 3 and 4. As a result of that review, Unit 3 was expected to remain in commercial service until 2011, providing an additional two years of power generation before refurbishment. After the refurbishment, the operating life of Unit 3 was to be extended to 2038. The review also showed that Unit 4 was expected to remain in commercial service until 2016, providing seven years of generation before refurbishment, after which the estimated operating life of Unit 4 was expected to be extended to 2042.

Further amendments to the agreement were made in July 2009. In addition to the amendments made to the Bruce B floor price mechanism, described in the Energy – Financial Analysis section of this MD&A, other changes to the contract with the OPA included the removal of a support payment cap for Bruce A. The cumulative support payments received by Bruce A, which are equal to the difference between the fixed prices under the OPA contract and spot market prices, were originally capped at $575 million until both Units 1 and 2 were restarted. The amendment provides that should either of the restarted Units 1 and 2 not be placed into commercial service by December 31, 2011, Bruce A will receive no further support payments and all output will receive spot prices until the restart is complete, at which point the Bruce A price will return to the then prevailing contract levels.

The July 2009 amendment also provided for deemed generation payments to Bruce Power at the contract prices when Bruce Power generation is reduced due to system curtailments on the IESO-controlled grid in Ontario.

Additionally, the capital cost-sharing mechanism for the refurbishment and restart of Bruce A Units 1 and 2 was amended to eliminate the requirement that the OPA share in any cost overruns exceeding $3.4 billion. Previously the OPA was responsible for 25 per cent of cost overruns above $3.4 billion through a future adjustment to the fixed price paid to Bruce Power for power generated by the Bruce A units.

The refurbishment and restart of Bruce A Units 1 and 2 is continuing with a focus on the reassembly of the reactors and related activities. As of December 31, 2009, Bruce A had incurred approximately $3.2 billion in costs for the refurbishment and restart of these units and approximately $0.2 billion for the refurbishment of Units 3 and 4. TransCanada believes that the Company's share of the total capital cost to complete the Unit 1 and 2 refurbishment and restart program will be approximately $2 billion. The bulk of the highly technical, high-risk work on this project is now finished or nearing completion. Although a significant amount of work remains to be completed, most of it involves conventional power plant construction activity. A project optimization plan implemented by Bruce Power last year is achieving success in improving productivity. TransCanada expects that Unit 2 will be restarted in mid-2011, with the Unit 1 restart following approximately four months later.

Bruce Power continues to advance an initiative to further extend the operating lives of Units 3 and 4. Unit 4 is now expected to continue to operate beyond 2018 and plans are in place to implement an extensive maintenance program that would result in the life of Unit 3 being extended for a similar period of time.

Portlands Energy Portlands Energy was completed under budget and fully commissioned in April 2009. The power plant, which is 50 per cent owned by TransCanada, is able to provide 550 MW of electricity under a 20 year Accelerated Clean Air Supply contract with the OPA.

Coolidge In August 2009, TransCanada began construction of the US$500 million Coolidge generating station located near Phoenix, Arizona. The first of 12 gas-fired turbines began arriving on site in January 2010. The 575 MW, simple-cycle, natural gas-fired peaking power facility is expected to be in service in second quarter 2011. All of the power produced by the facility will be sold under a 20 year PPA to the Salt River Project Agricultural Improvement and Power District based in Phoenix, Arizona.

Halton Hills Construction of Halton Hills continued in 2009 and is nearing completion. The project is a 683 MW natural gas-fired power plant near Halton Hills, Ontario and is expected to be in operation in third quarter 2010 following commissioning, start-up and testing. TransCanada expects to invest approximately $700 million in the project. Power from the facility will be sold to the OPA under a 20 year Clean Energy Supply contract.

Cartier Wind In third quarter 2009, construction activity began on the 212 MW Gros-Morne and 58 MW Montagne-Sèche wind farms. The Montagne-Sèche project and phase one of the Gros-Morne project (101 MW) are expected to be operational in 2011. Phase two of the Gros-Morne project (111 MW) is expected to be operational in 2012. Gros-Morne and Montagne-Sèche are the fourth and fifth Québec-based wind farms of the Cartier Wind project. Once they are complete, Cartier Wind, which is 62 per cent owned by TransCanada, will be capable of producing 590 MW of electricity. All of the power produced by Cartier Wind is sold to Hydro-Québec under a 20 year PPA. In fourth quarter 2009, the proposed 150 MW Les Méchins wind farm, the sixth project in Cartier Wind, was cancelled due to the unavailability of cost-effective wind turbines and difficulty reaching acceptable agreements with private landowners. This decision has no impact on the other Cartier Wind projects.

Kibby Wind In October 2009, the first phase of the Kibby Wind power project, including 22 turbines capable of producing a combined 66 MW of power, was placed in service six weeks ahead of schedule and under budget. Construction continues on the 66 MW second phase of the project, which includes the installation of an additional 22 turbines. This phase is expected to be in service in third quarter 2010. Total cost of construction for both phases of the project is expected to be approximately US$350 million. The project is expected to be eligible for government incentive payments under the federal U.S. stimulus package.

Bécancour In June 2009, TransCanada entered into an agreement with Hydro-Québec to continue to suspend all electricity generation from the Bécancour power plant through 2010. Hydro-Québec has the option, subject to certain conditions, to extend the suspension on an annual basis until such time as regional electricity demand levels recover. TransCanada receives payments under this agreement similar to those that would have been received under the normal course of operation.

Oakville In September 2009, the OPA awarded TransCanada a 20 year Clean Energy Supply contract to build, own and operate the 900 MW Oakville power generating station in Oakville, Ontario. TransCanada expects to invest approximately $1.2 billion in the natural gas-fired, combined-cycle plant, which is anticipated to be in service in first quarter 2014.

Power Transmission Line Projects TransCanada's open seasons for capacity on its proposed Zephyr and Chinook power transmission line projects closed in December 2009. A comprehensive review of the bids submitted for each project is underway. Each project would be capable of delivering primarily renewable (wind-generated) power originating in Wyoming (Zephyr) and Montana (Chinook) to Nevada.

Broadwater – LNG In April 2009, the U.S. Department of Commerce issued a decision upholding New York State's objection to the proposed construction and operation of the Broadwater LNG project, a joint venture between TransCanada and Shell Broadwater Holdings, LLC. The Broadwater Energy partnership has scaled back near term activities and is assessing its future options with respect to this project.

ENERGY – BUSINESS RISKS

Fluctuating Power and Natural Gas Market Prices TransCanada operates in competitive power and natural gas markets in North America. Volatility in power and natural gas prices is caused by fluctuating supply and demand, and by general economic conditions. Energy's earnings from the sale of uncontracted volumes are subject to price volatility. Although Energy commits a significant portion of its supply to medium- to long-term sales contracts, it retains an amount of unsold supply in order to provide flexibility in managing the Company's portfolio of wholly owned assets.

Capacity Payments U.S. Power capacity payments are reset periodically each year and are affected by the start-up and retirement of power facilities and by fluctuations in demand.

Uncontracted Volumes Energy has uncontracted power sales volumes in Western Power and U.S. Power. With the 2008 acquisition of Ravenswood, the level of uncontracted sales volumes in U.S. Power significantly increased. Sales of uncontracted power volumes into the spot market are subject to market price volatility, which directly impacts earnings. In addition, as power sales contracts expire, any new contracts are entered into at the prevailing market prices. In 2009, prices realized on these new contracts were generally lower than in recent years due to the significant decrease in power prices in TransCanada's core power markets.

Bruce B volumes are subject to a floor price mechanism. When the spot market price is above the floor price, Bruce B's non-contracted volumes are subject to spot price volatility. When spot prices are below the floor price, Bruce B receives the floor price. However, Bruce B's results during this period are still subject to the impact of fluctuating spot prices upon the settlement of contracted sales. All of the Bruce A output is sold into the Ontario wholesale power spot market under fixed contract price terms with the OPA and 100 per cent of Eastern Power sales volumes are sold under long-term contracts.

Energy's natural gas storage business is subject to fluctuating natural gas seasonal spreads generally determined by the differential in natural gas prices in the traditional summer injection and winter withdrawal seasons. As a result, the Company hedges capacity with a portfolio of contractual capacity sales commitments.

Liquidity Risk A decrease in the number and credit quality of counterparties may increase the Company's exposure to spot prices by reducing its ability to lock in forward sale prices at acceptable contract terms.

Plant Availability Maintaining plant availability is essential to the continued success of the Energy business. Plant operating risk is mitigated through a commitment to TransCanada's operational excellence strategy, which is to provide low-cost, reliable operating performance at each of the Company's facilities. Unexpected plant outages, including unexpected delays in completing planned outages, could result in lower plant output and sales revenue, reduced capacity payments and margins, and increased maintenance costs. At certain times, unplanned outages may require power or natural gas purchases at market prices to ensure TransCanada meets its contractual obligations.

Weather Extreme temperature and weather events in North America and the Gulf of Mexico often create price volatility and variable demand for power and natural gas. These events may also restrict the availability of power and natural gas. Seasonal changes in temperature can also affect the efficiency and output capability of natural gas-fired power plants. Variability in wind speeds may impact the earnings of Energy's wind assets.

Hydrology TransCanada's power operations are subject to hydrology risk arising from the ownership of hydroelectric power generation facilities in the northeastern U.S. Weather changes, weather events, local river management and potential dam failures at these plants or upstream facilities pose potential risks to the Company.

Execution, Capital Cost and Permitting Energy's new construction programs in Ontario, Québec, Maine and Arizona, including its investment in Bruce Power, are subject to execution, capital cost and permitting risks.

Asset Commissioning Although each of TransCanada's newly constructed assets goes through rigorous acceptance testing prior to being placed in service, there is a risk that these assets may have lower than expected availability or performance, especially in their first year of operations.

Regulation of Power Markets TransCanada operates in both regulated and deregulated power markets. As power markets evolve across North America, there is the potential for regulatory bodies to implement new rules that could negatively affect TransCanada as a generator and marketer of electricity. These may be in the form of market rule changes, price caps, emission controls, unfair cost allocations to generators and attempts by others to take out-of-market actions to build excess generation that negatively affects the price of capacity or energy, or both. In addition, TransCanada's development projects rely on an orderly permitting process and any disruption to that process can have negative effects on project schedules and costs. TransCanada continues to monitor regulatory issues and regulatory reform and participate in and lead related discussions.

Refer to the Risk Management and Financial Instruments section of this MD&A for information on additional risks and managing risks in the Energy business.

ENERGY – OUTLOOK

TransCanada assumes that results from its Energy operations in 2010 will be materially consistent with those in 2009 and will include the positive impact of a full year of earnings from Portlands Energy and phase one of Kibby Wind, as well as incremental earnings from Halton Hills and phase two of Kibby Wind, which are expected to be commissioned in third quarter 2010.

The Company expects capacity prices in the New York City market, in which Ravenswood operates, to improve with the long-planned retirement of a power generating facility owned by the New York Power Authority which occurred at the end of January 2010. The positive impact from this facility's retirement may be partially offset by some reductions in demand in this market, driven by the economic downturn and the results of energy efficiency investments being made in the region.

The current economic climate continues to negatively affect demand, liquidity and prices in commodity markets in which TransCanada's Energy segment operates. Earnings in Western Power, Bruce Power and U.S. Power are expected to be negatively impacted in the near term by the expiry of existing forward sale contracts as new contracts would generally be negotiated at lower prices.

Although TransCanada has sold forward significant output from its power plants and Alberta PPAs, as well as capacity from its natural gas storage facilities, Energy's EBITDA in 2010 can be affected by changes in factors such as the spot market price of power, market heat rates, hydrology, capacity payments, natural gas storage spreads and unplanned outages. EBITDA from Energy's U.S. operations is also affected by changes in foreign currency exchange rates.

Other factors such as plant availability, regulatory changes, weather, currency movements and overall stability of the energy industry can also affect 2010 EBITDA. Refer to the Energy – Business Risks section of this MD&A for a complete discussion of these factors.

Capital Expenditures Energy's total capital expenditures in 2009 were $1.5 billion. Energy's overall capital spending in 2010 is expected to be approximately $1.3 billion, including cash calls for the Bruce A refurbishment and restart project, and continued construction at Coolidge, Cartier Wind, Kibby Wind, Halton Hills and Oakville.

CORPORATE

Corporate EBIT losses for the year ended December 31, 2009 were $117 million compared to losses of $104 million and $102 million in 2008 and 2007, respectively. The increases in EBIT losses were primarily due to higher support services costs, reflecting a growing asset base.

OTHER INCOME STATEMENT ITEMS

INTEREST EXPENSE
Year ended December 31 *(millions of dollars)*

	2009	2008	2007
Interest on long-term debt[1]	**1,285**	1,038	991
Other interest and amortization	**27**	46	20
Capitalized interest	**(358)**	(141)	(68)
	954	943	943

[1] Includes interest for Junior Subordinated Notes

Interest expense in 2009 increased $11 million to $954 million from $943 million in each of 2008 and 2007. The increase in interest on long-term debt reflected new debt issues of US$1.5 billion and $500 million in August 2008, US$2.0 billion in January 2009 and $700 million in February 2009. In addition, U.S. dollar-denominated interest expense increased in 2009 due to the impact of a stronger U.S. dollar. These increases were partially offset by higher capitalization of interest to finance the Company's larger capital spending program primarily due to the construction of Keystone and the acquisition in 2009 of the remaining ownership interest in Keystone from ConocoPhillips. Interest expense in 2009 was positively impacted by reduced losses from changes in the fair value of derivatives used to manage TransCanada's exposure to fluctuating interest rates. Interest expense in 2008 of $943 million was consistent with 2007. Higher financial charges resulting from financing the Company's 2008 capital program, including the Ravenswood acquisition, and higher losses from changes in the fair value of derivatives used to manage the Company's exposure to rising interest rates were offset by increased capitalization of interest to finance the Company's larger capital spending program.

Interest income and other was $121 million in 2009 compared to $54 million and $120 million in 2008 and 2007, respectively. The increase of $67 million in 2009 compared to 2008 was primarily due to the positive impact of a weakening U.S. dollar throughout 2009 on U.S. dollar working capital balances and higher gains from derivatives used to manage the Company's exposure to foreign exchange rate fluctuations. An increase in interest income due to higher cash balances held in 2009 than in 2008 was more than offset by lower interest rates. The decrease of $66 million in 2008 compared to 2007 was primarily due to lower gains from derivatives used to manage the Company's exposure to foreign exchange rate fluctuations and the negative impact of a strengthening U.S. dollar throughout 2008.

Income taxes were $387 million, $602 million and $490 million in 2009, 2008 and 2007, respectively. The decrease of $215 million in 2009 compared to 2008 was primarily due to reduced pre-tax earnings, higher income tax savings from income tax rate differentials and other positive income tax adjustments in 2009, including $30 million of favourable adjustments arising from a reduction in the Province of Ontario's corporate income tax rates. The increase in income tax expense of $112 million in 2008 compared to 2007 was primarily due to positive income tax adjustments recorded in 2007 and higher pre-tax earnings in 2008.

Non-controlling interests were $96 million in 2009 compared to $130 million and $97 million in 2008 and 2007, respectively. The decrease in 2009 compared to 2008 was primarily due to the non-controlling interests' portion of Portland's Calpine bankruptcy settlements in 2008, partially offset by higher PipeLines LP earnings and the impact of a stronger U.S. dollar in 2009. The increase in 2008 compared to 2007 was primarily due to the non-controlling interests' portion of Portland's Calpine bankruptcy settlements in 2008.

LIQUIDITY AND CAPITAL RESOURCES

TransCanada's financial position remains sound and consistent with recent years as does its ability to generate cash in the short and long term to provide liquidity, maintain financial capacity and flexibility, and to provide for planned growth. TransCanada's liquidity position remains solid, underpinned by predictable cash flow from operations, significant cash balances on hand from recent common and preferred share and debt issues, as well as committed revolving bank lines of US$1.0 billion, $2.0 billion, US$1.0 billion and US$300 million, maturing in November 2010, December 2012, December 2012 and February 2013, respectively. In addition, TransCanada's proportionate share of capacity remaining available on committed bank facilities at TransCanada-operated affiliates was $143 million with maturity dates from 2010 through 2012. The Company operates commercial paper programs in Canada and, as at December 31, 2009, had remaining capacity of $2.45 billion, $2.0 billion and US$4.0 billion under its equity, Canadian debt and U.S. debt shelf prospectuses, respectively. In lieu of making cash dividend payments, a portion of the declared common and preferred dividends are expected to be paid in common shares issued under the Company's DRP. TransCanada's liquidity, market and other risks are discussed further in the Risk Management and Financial Instruments section of this MD&A.

SUMMARIZED CASH FLOW
Year ended December 31 *(millions of dollars)*

	2009	2008	2007
Funds generated from operations[1]	**3,080**	3,021	2,621
(Increase)/decrease in operating working capital	**(90)**	135	63
Net cash provided by operations	**2,990**	3,156	2,684

[1] Refer to the Non-GAAP Measures section of this MD&A for further discussion of funds generated from operations.

HIGHLIGHTS

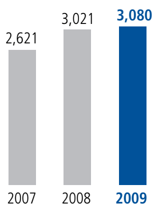
Investing Activities
- Capital expenditures and acquisitions, including assumed debt, totalled approximately $20 billion over the three year period ending December 31, 2009.

Dividends
- TransCanada's Board of Directors declared a $0.40 per common share dividend for the quarter ending March 31, 2010, an increase of five per cent over the previous dividend amount. The Board also declared a quarterly dividend of $0.2875 per preferred share for the quarter ending March 31, 2010.

CASH FLOW AND CAPITAL RESOURCES

Funds Generated from Operations

Funds Generated from Operations (millions of dollars)

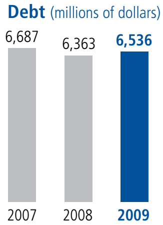


Funds generated from operations were $3.1 billion in 2009 compared to $3.0 billion and $2.6 billion, in 2008 and 2007, respectively. The increase in 2009 compared to 2008 was primarily due to increased cash from earnings, partially offset by increased pension contributions in 2009 and the $152 million after tax Calpine bankruptcy settlements in 2008. The Energy business and the Calpine bankruptcy settlements were the primary sources of the increase in 2008 compared to 2007.

Investing Activities

Capital expenditures totalled $5.4 billion in 2009 compared to $3.1 billion in 2008 and $1.7 billion in 2007. Expenditures in 2009 and 2008 related primarily to Keystone construction, the refurbishment and restart at Bruce A, construction of other new pipeline and power facilities, plus the expansion and maintenance of existing pipelines. In addition, in 2009, the Company incurred $3.3 billion of costs related to Keystone, including approximately $400 million related to the development of the Gulf Coast expansion. Expenditures in 2007 were related primarily to the refurbishment and restart at Bruce A, construction of new power plants in Canada and maintenance and capacity projects in the Pipelines business.

Capital Expenditures and Acquisitions, including Assumed Debt (millions of dollars)



In August 2009, the Company purchased ConocoPhillips' remaining approximate 20 per cent interest in Keystone for US$553 million plus the assumption of US$197 million of short-term debt. Acquisitions in 2009 also included previous increases in ownership interest in Keystone from ConocoPhillips, discussed below. TransCanada now owns 100 per cent of Keystone.

In 2008, TransCanada entered into an agreement with ConocoPhillips to increase its equity ownership in Keystone to approximately 80 per cent from 50 per cent, with ConocoPhillips' equity ownership in Keystone being reduced concurrently to approximately 20 per cent from 50 per cent. In 2008 and prior to August 2009, TransCanada funded 100 per cent of the construction expenditures until the participants' cumulative project capital contributions were aligned with their revised ownership interests. In 2009, prior to August, TransCanada funded $1.3 billion of cash calls for Keystone, resulting in the Company acquiring an incremental increase in ownership of approximately 18 per cent for $313 million. In 2008, the Company funded $362 million of cash calls, resulting in an incremental increase in ownership of approximately 12 per cent for $176 million. TransCanada's ownership interest was approximately 80 per cent and 62 per cent in August 2009 and at December 31, 2008, respectively.

TransCanada acquired Ravenswood from National Grid plc on August 26, 2008 for US$2.9 billion.

In 2007, TransCanada acquired ANR and an additional 3.6 per cent interest in Great Lakes from El Paso Corporation for US$3.4 billion, including US$491 million of assumed long-term debt. PipeLines LP acquired the remaining 46.4 per cent of Great Lakes from El Paso Corporation for US$942 million, including US$209 million of assumed long-term debt.

Financing Activities

In 2009, TransCanada issued long-term debt of $3.3 billion and its proportionate share of long-term debt issued by joint ventures was $226 million. Also in 2009, the Company reduced its long-term debt by $1.0 billion, its proportionate share of the long-term debt of joint ventures by $246 million and notes payable by $244 million. This financing activity included the items noted below.

At December 31, 2009, total committed revolving and demand credit facilities of $5.2 billion were available to support the Company's commercial paper programs and for general corporate purposes. These unsecured credit facilities included the following:

- A $2.0 billion committed, syndicated revolving TransCanada PipeLines Limited (TCPL) credit facility, maturing December 2012. The facility was fully available at December 31, 2009 and supports TCPL's commercial paper program.
- a US$300 million committed, syndicated revolving credit facility, guaranteed by TransCanada, maturing February 2013. This facility is part of the US$1.0 billion TransCanada PipeLine USA Ltd. (TCPL USA) credit facility discussed below under the heading 2007 Long-Term Debt Financing Activities. At December 31, 2009, this facility was fully drawn.
- a US$1.0 billion committed, syndicated revolving TransCanada Keystone Pipeline, L.P. credit facility, guaranteed by TCPL, maturing November 2010 but extendible to November 2011 at the option of the borrower. The facility was fully available at December 31, 2009 and supports a commercial paper program dedicated to funding a portion of expenditures for Keystone and for Keystone general partnership purposes.
- a US$1.0 billion committed, syndicated revolving TCPL USA credit facility established in fourth quarter 2009, maturing December 2012, with a one year extension at the option of the borrower. The facility is guaranteed by TransCanada and was fully available at December 31, 2009. This facility will be used to partially fund the Company's capital program and for general corporate purposes.
- demand lines totalling $805 million, which support the issuance of letters of credit and provide additional liquidity. The Company had used approximately $467 million of these demand lines for letters of credit at December 31, 2009.

The Company is well positioned to fund its existing capital program through its growing internally-generated cash flow, its DRP and its continued access to capital markets. As demonstrated by the recent sale of North Baja to PipeLines LP, TransCanada will also continue to examine opportunities for portfolio management, including a greater role for PipeLines LP, in financing its capital program.

In July 2009, TransCanada sold North Baja to PipeLines LP. As part of the transaction, TransCanada agreed to amend its incentive distribution rights with PipeLines LP. TransCanada received aggregate consideration totalling approximately US$395 million from PipeLines LP, including US$200 million in cash and 6,371,680 common units of PipeLines LP. PipeLines LP utilized US$170 million of its US$250 million committed and available bank facility to partially fund this transaction, which resulted in TransCanada's ownership in PipeLines LP increasing to 42.6 per cent. Subsequent to this transaction, TransCanada's ownership in PipeLines LP decreased to 38.2 per cent due to PipeLines LP's public issuance of common units as discussed under the heading 2009 Equity Financing Activities in this section.

Short-Term Debt Financing Activities

In June 2008, TCPL executed an agreement with a syndicate of banks for a US$1.5 billion committed, unsecured, one year bridge loan facility, which was extendible at the option of the Company for an additional six-month term. In August 2008, the Company used US$255 million from this facility to fund a portion of the Ravenswood acquisition and cancelled the remainder of the commitment. In February 2009, the US$255 million was repaid and the facility was cancelled.

In February 2007, TransCanada established a US$2.2 billion, committed, unsecured, one-year bridge loan facility and utilized a combined $1.5 billion and US$700 million to partially finance its acquisition of ANR and its increased ownership of Great Lakes. At December 31, 2008, this facility had been fully repaid and cancelled.

2009 Long-Term Debt Financing Activities

In December 2009, TCPL filed a debt base shelf prospectus qualifying for the issuance of up to US$4.0 billion of debt securities in the U.S. This prospectus replaced a US$3.0 billion debt base shelf prospectus filed in January 2009, which had remaining capacity of US$1.0 billion. No amounts have been issued under the December 2009 base shelf prospectus.

In April 2009, TCPL filed a $2.0 billion Canadian Medium-Term Notes base shelf prospectus to replace a March 2007 $1.5 billion Canadian Medium-Term Notes base shelf prospectus, which expired in April 2009. No amounts have been issued under the April 2009 base shelf prospectus.

In February 2009, TCPL issued Medium-Term Notes of $300 million and $400 million maturing in February 2014 and February 2039, respectively, and bearing interest at 5.05 per cent and 8.05 per cent, respectively. The proceeds were used to fund the Alberta System and Canadian Mainline rate bases. These notes were issued by way of a pricing supplement under a Canadian $1.5 billion debt base shelf prospectus filed in March 2007.

In January 2009, TCPL issued Senior Unsecured Notes of US$750 million and US$1.25 billion maturing in January 2019 and January 2039, respectively, and bearing interest at 7.125 per cent and 7.625 per cent, respectively. The proceeds were used to partially fund TransCanada's capital projects, retire maturing debt obligations and for general corporate purposes. These notes were issued by way of a prospectus supplement under a US$3.0 billion debt base shelf prospectus filed by TCPL in January 2009.

In September 2009, TQM issued $75 million of bonds maturing in September 2014 and bearing interest at 4.05 per cent.

In August 2009, Northern Border issued US$100 million of Senior Unsecured Notes maturing in August 2016 and bearing interest at 6.24 per cent.

In May 2009, Iroquois issued US$140 million of Senior Unsecured Notes maturing in May 2019 and bearing interest at 6.63 per cent.

In October 2009, the Company retired $250 million of 10.625 per cent debentures.

In February 2009, the Company retired $200 million of 4.10 per cent Medium-Term Notes.

In January 2009, the Company retired US$227 million of 6.49 per cent Medium-Term Notes.

In September 2009, Northern Border retired US$200 million of 7.75 per cent Senior Notes.

In August 2009, TQM retired $100 million of 6.50 per cent Series H Bonds.

2008 Long-Term Debt Financing Activities

In 2008, TransCanada issued long-term debt of $2.2 billion, increased its notes payable by $1.3 billion and its proportionate share of long-term debt issued by joint ventures was $173 million. The Company also reduced its long-term debt by $840 million and its proportionate share of the long-term debt of joint ventures by $120 million. This financing activity included the items noted below.

In August 2008, TCPL issued $500 million of Medium-Term Notes maturing in August 2013 and bearing interest at 5.05 per cent. The proceeds from these notes were used to partially fund the Alberta System's capital program and for general corporate purposes. These notes were issued by way of pricing supplement under the Canadian $1.5 billion debt base shelf prospectus filed in March 2007.

In August 2008, TCPL issued US$850 million and US$650 million of Senior Unsecured Notes maturing in August 2018 and August 2038, respectively, and bearing interest at 6.50 per cent and 7.25 per cent, respectively. The proceeds from these notes were used to partially fund the Ravenswood acquisition and for general corporate purposes. These notes were issued by way of a prospectus supplement under a US$2.5 billion debt base shelf prospectus filed in September 2007, which was fully utilized following these issuances.

In June 2008, the Company retired $256 million of 5.84 per cent Medium-Term Notes and a $100 million 11.85 per cent debenture. In January 2008, the Company retired $105 million of 6.0 per cent Medium-Term Notes.

2007 Long-Term Debt Financing Activities

In 2007, TransCanada issued long-term debt of $2.6 billion and junior subordinated notes of US$1.0 billion, and its proportionate share of long-term debt issued by joint ventures was $142 million. The Company also reduced its long-term debt by $1.1 billion, its notes payable by $46 million and its proportionate share of the long-term debt of joint ventures by $157 million. This financing activity included the items noted below.

In October 2007, TCPL issued US$1.0 billion of Senior Unsecured Notes maturing on October 15, 2037 and bearing interest at 6.2 per cent. These notes were issued under the US$2.5 billion debt base shelf prospectus filed by TCPL in September 2007.

In July 2007, TCPL exercised its rights to redeem the US$460 million 8.25 per cent Preferred Securities due 2047. The Preferred Securities were redeemed for cash, at par, as agreed to in a settlement for the Canadian Mainline. The foreign exchange gain realized on redemption of the securities will flow through to Canadian Mainline shippers over the five-year period of the settlement.

In April 2007, TCPL issued US$1.0 billion of Junior Subordinated Notes, maturing in 2067 and bearing interest at 6.35 per cent per year until May 15, 2017, when interest will convert to a floating interest rate of three-month LIBOR plus 221 basis points. The Junior Subordinated Notes are subordinated to all existing and future TCPL senior indebtedness, are effectively subordinated to all indebtedness and other obligations of TCPL, and are callable at TCPL's option at any time on or after May 15, 2017 at the principal amount plus accrued and unpaid interest. The notes were issued by way of prospectus supplement pursuant to a U.S. debt base shelf prospectus filed in March 2007.

In April 2007, Northern Border increased its five year bank facility to US$250 million from US$175 million. A portion of the bank facility was drawn to refinance US$150 million of Senior Notes that matured in May 2007, with the balance available to fund Northern Border's ongoing operations.

In March 2007, ANR Pipeline voluntarily withdrew the New York Stock Exchange listing of its 9.625 per cent debentures due 2021, 7.375 per cent debentures due 2024, and 7.0 per cent debentures due 2025. With the delisting, ANR Pipeline deregistered these securities with the SEC.

In February 2007, TCPL USA established the US$1.0 billion committed, unsecured credit facility, consisting of a US$700 million five year term loan, maturing in 2012 and a US$300 million extendible revolving facility, maturing in February 2013. The Company utilized US$1.0 billion from this facility and an additional US$100 million from an existing demand line to partially finance the ANR acquisition and increased ownership in Great Lakes, as well as its additional investment in PipeLines LP in 2007. The facility is guaranteed by TransCanada. There was an outstanding balance of US$700 million on the term loan at December 31, 2009 and 2008.

In February 2007, PipeLines LP increased the size of its syndicated revolving credit and term loan facility in connection with its Great Lakes acquisition. The amount available under the facility increased to US$950 million from US$410 million and consisted of a US$700 million senior term loan and a US$250 million senior revolving credit facility, with US$194 million of the available senior term loan amount being terminated upon closing of the Great Lakes acquisition. At December 31, 2009, US$475 million was outstanding on the senior term loan. The US$250 million senior revolving credit facility will terminate in December 2011.

In October 2007, the Company retired $150 million of 6.15 per cent Medium-Term Notes. In February 2007, the Company retired $275 million of 6.05 per cent Medium-Term Notes.

2009 Equity Financing Activities

In September 2009, TransCanada completed a public offering of 22 million cumulative redeemable first preferred shares under a prospectus supplement to the September 2009 base shelf prospectus, discussed below, for gross proceeds of $550 million. The holders of the preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.15 per share, payable quarterly, for the initial five year period ending December 31, 2014, with the first dividend paid on December 31, 2009. The dividend rate will reset on December 31, 2014 and every five years thereafter to a yield per annum equal to the sum of the then five year Government of Canada bond yield plus 1.92 per cent. The preferred shares are redeemable by TransCanada on or after December 31, 2014 at a price of $25 per share plus all accrued and unpaid dividends. The preferred shareholders are eligible to participate in the Company's DRP. The net proceeds of the offering were used to partially fund capital projects, for general corporate purposes and to repay short-term indebtedness.

The preferred shareholders will have the right to convert their shares into Series 2 cumulative redeemable first preferred shares on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.92 per cent.

In September 2009, TransCanada filed a base shelf prospectus qualifying for issuance $3.0 billion of common shares, first or second preferred shares and/or subscription receipts in Canada and the U.S. until October 2011. This base shelf prospectus replaced the base shelf prospectus filed in July 2008 which was depleted by the common share issuance in June 2009. The Company had $2.45 billion available under this prospectus at December 31, 2009.

In June 2009, TransCanada completed a public offering of 58.4 million common shares, including full exercise of a 15 per cent over-allotment option by the underwriters, at a purchase price of $31.50 per share. Proceeds from the common share offering and the over-allotment option totalled $1.8 billion and were used by TransCanada to partially fund its capital projects, including the acquisition of the remaining interest in Keystone, for general corporate purposes and to repay short-term indebtedness.

On November 19, 2009, PipeLines LP completed a public offering of five million common units at a price of US$38.00 per unit, resulting in net proceeds to PipeLines LP of US$182 million. TransCanada contributed an additional US$4 million to maintain its general partnership interest but did not purchase any units. Upon completion of this offering, TransCanada's ownership interest in PipeLines LP was 38.2 per cent.

2008 Equity Financing Activities

In fourth quarter 2008, TransCanada completed a public offering of common shares at a purchase price of $33.00 per share. The issue of 35.1 million common shares, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.2 billion. The proceeds of the offering were used by TransCanada to partially fund its capital projects, including Keystone, for general corporate purposes and to repay short-term indebtedness. The common shares were issued under a prospectus supplement to the base shelf prospectus filed in July 2008.

In July 2008, TransCanada filed a base shelf prospectus in Canada and the U.S. qualifying for issuance $3.0 billion of common shares, preferred shares and/or subscription receipts in Canada and the U.S. until August 2010. The shelf replaced a base shelf prospectus filed in January 2007.

In May 2008, TransCanada completed a public offering of common shares at a purchase price of $36.50 per share. The issue of 34.7 million common shares, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.3 billion. These proceeds were used to partially fund the Ravenswood acquisition and the Company's capital projects, and for general corporate purposes. These common shares were issued by prospectus supplement under the base shelf prospectus filed in January 2007.

2007 Equity Financing Activities

In first quarter 2007, TransCanada issued 45.4 million common shares at a purchase price of $38.00 per share by prospectus supplement under a base shelf prospectus filed in Canada and the U.S. in January 2007, resulting in gross proceeds of $1.7 billion. The proceeds were used in financing the acquisition of ANR and Great Lakes.

In February 2007, PipeLines LP completed a private placement offering of 17.4 million common units at a purchase price of US$34.57 per unit. TransCanada acquired 50 per cent of the units for US$300 million and invested an additional US$12 million to maintain its general partnership ownership interest in PipeLines LP. The total private placement plus TransCanada's additional investment resulted in gross proceeds to PipeLines LP of US$612 million, which were used to partially finance its Great Lakes acquisition.

Dividend Reinvestment and Share Purchase Plan
Commencing in 2007, TransCanada's Board of Directors authorized the issuance of common shares from treasury at a discount to participants in the Company's DRP. Under this plan, eligible holders of common or preferred shares of TransCanada and preferred shares of TCPL may reinvest their dividends and make optional cash payments to obtain TransCanada common shares. The DRP shares are provided to the participants at a discount to the average market price in the five days before dividend payment. The discount was set at two per cent commencing with the dividend payable in April 2007 and was increased to three per cent commencing with the dividend payable in January 2009. Prior to the April 2007 dividend, TransCanada purchased shares on the open market and provided them to DRP participants at cost. The Company reserves the right to alter the discount or return to purchasing shares on the open market at any time. In 2009, dividends of $254 million were paid (2008 – $218 million; 2007 – $157 million) through the issuance of 8.2 million (2008 – 6.0 million; 2007 – 4.1 million) common shares from treasury in accordance with the DRP.

Dividends
Cash dividends on common shares amounting to $722 million were paid in 2009 (2008 – $577 million; 2007 – $546 million). In addition, cash dividends of $6 million were paid on preferred shares in 2009. The increase in common share dividends paid in 2009 from 2008 was primarily due to a greater number of shares outstanding and an increase in the dividend per share amount in 2009, partially offset by the issuance of $254 million of common shares under the DRP in lieu of cash dividends. The increase in common share dividends paid in 2008 from 2007 was primarily due to a greater number of shares outstanding and an increase in the dividend per share amount in 2008, partially offset by the Company's issuance in 2008 of $218 million (2007 – $157 million) of common shares from treasury under the DRP in lieu of cash dividends.

In February 2010, TransCanada's Board of Directors approved an increase in the quarterly common share dividend payment to $0.40 per share from $0.38 per share for the quarter ending March 31, 2010. This was the tenth consecutive year in which the dividend was increased, resulting in a per share dividend that has doubled since 2000. In addition, a quarterly dividend of $0.2875 per preferred share was declared for the quarter ending March 31, 2010.

Issuer Ratings
TransCanada's issuer rating assigned by Moody's Investors Service (Moody's) is Baa1 with a stable outlook. On September 30, 2009, DBRS and Standard and Poor's (S&P) assigned ratings of Pfd-2 (low) and P-2, respectively, to TransCanada's cumulative redeemable first preferred shares, Series 1 and, in connection with the offering of the preferred shares, S&P assigned TransCanada an A− long-term corporate credit rating with a stable outlook. TCPL's senior unsecured debt is rated A with a stable outlook by DBRS, A3 with a stable outlook by Moody's, and A− with a stable outlook by S&P.

CONTRACTUAL OBLIGATIONS

Obligations and Commitments
At December 31, 2009, the Company had $16.7 billion of total long-term debt and $1.0 billion of junior subordinated notes, compared to $16.2 billion of total long-term debt and $1.2 billion of junior subordinated notes at December 31, 2008. TransCanada's share of the total debt of joint ventures, including capital lease obligations, was $1.0 billion at December 31, 2009, compared to $1.1 billion at December 31, 2008. Total notes payable, including TransCanada's proportionate share of the notes payable of joint ventures, were $1.7 billion at December 31, 2009 and December 31, 2008. TransCanada has provided certain pro-rata guarantees related to the capital lease and performance obligations of Bruce Power and certain other partially owned entities.

CONTRACTUAL OBLIGATIONS
Year ended December 31 *(millions of dollars)*

		Payments Due by Period			
	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt[1]	18,443	677	2,240	1,930	13,596
Capital lease obligations	222	13	33	43	133
Operating leases[2]	862	74	150	147	491
Purchase obligations	11,882	3,433	2,963	1,502	3,984
Other long-term liabilities reflected on the balance sheet	669	14	30	35	590
	32,078	4,211	5,416	3,657	18,794

(1) Includes junior subordinated notes and long-term debt of joint ventures, excluding capital lease obligations.

(2) Represents future annual payments, net of sub-lease receipts, for various premises, services and equipment. The operating lease agreements for premises, services and equipment expire at various dates through 2052 with an option to renew certain lease agreements for one to ten years.

TransCanada's commitments under the Alberta PPAs are considered to be operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Future payments under these PPAs have been excluded from operating leases in the above table, as these payments are dependent upon plant availability among other factors. TransCanada's share of power purchased under the PPAs in 2009 was $384 million (2008 – $398 million; 2007 – $391 million).

At December 31, 2009, scheduled principal repayments and interest payments related to long-term debt and the Company's proportionate share of the long-term debt of joint ventures were as follows:

PRINCIPAL REPAYMENTS
Year ended December 31 *(millions of dollars)*

		Payments Due by Period			
	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt	16,664	478	2,099	1,879	12,208
Junior subordinated notes	1,036	–	–	–	1,036
Long-term debt of joint ventures	743	199	141	51	352
	18,443	677	2,240	1,930	13,596

INTEREST PAYMENTS
Year ended December 31 *(millions of dollars)*

		Payments Due by Period			
	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt	16,625	1,120	2,127	1,960	11,418
Junior subordinated notes	498	66	133	133	166
Long-term debt of joint ventures	305	46	73	65	121
	17,428	1,232	2,333	2,158	11,705

At December 31, 2009, the Company's approximate future purchase obligations were as follows:

PURCHASE OBLIGATIONS[1]
Year ended December 31 *(millions of dollars)*

		Payments Due by Period			
	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Pipelines					
Transportation by others[2]	693	243	281	104	65
Capital expenditures[3][4]	2,043	1,417	621	5	–
Other	67	8	12	10	37
Energy					
Commodity purchases[5]	6,533	877	1,235	1,189	3,232
Capital expenditures[3][6]	1,341	745	596	–	–
Other[7]	1,161	117	209	188	647
Corporate					
Information technology and other	44	26	9	6	3
	11,882	3,433	2,963	1,502	3,984

(1) The amounts in this table exclude funding contributions to pension plans and funding to the APG.

(2) Rates are based on known 2010 levels. Beyond 2010, demand rates are subject to change. The purchase obligations in the table are based on known or contracted demand volumes only and exclude commodity charges incurred when volumes flow.

(3) Amounts are estimates and are subject to variability based on timing of construction and project enhancements. The Company expects to fund capital projects with cash from operations and, if necessary, new debt and equity.

(4) Capital expenditures are primarily related to the construction costs of Keystone, North Central Corridor, Guadalajara, Bison and other pipeline projects.

(5) Commodity purchases include fixed and variable components. The variable components are estimates and are subject to variability in plant production, market prices and regulatory tariffs.

(6) Capital expenditures are primarily related to TransCanada's share of the construction and development costs of Oakville, Bruce Power, Coolidge, Halton Hills and phase two of Kibby Wind.

(7) Includes estimates of certain amounts that are subject to change depending on plant fired hours, the consumer price index, actual plant maintenance costs, plant salaries and changes in regulated rates for transportation.

TransCanada and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business. Potential future commitments are discussed in the Pipelines – Opportunities and Developments and Energy – Opportunities and Developments sections in this MD&A.

In 2010, TransCanada expects to make funding contributions of approximately $115 million for the defined benefit pension plans and approximately $28 million for the Company's other post-retirement benefit plans, savings plan and defined contribution pension plans. This represents a decrease from total funding contributions of $168 million in 2009 and is attributable primarily to significantly improved investment performance and to plan experience being different than expectations. TransCanada's proportionate share of funding contributions expected to be made by joint ventures to their respective pension and other post-retirement benefit plans in 2010 is approximately $57 million and $6 million, respectively, compared to total contributions of $54 million in 2009.

The next actuarial valuation for the Company's pension and other post-retirement benefit plans will be carried out as at January 1, 2011. TransCanada expects funding requirements for these plans to continue at the anticipated 2010 level for the next several years to amortize solvency deficiencies in addition to normal costs. The Company's 2010 net benefit cost is expected to increase modestly from 2009. However, future net benefit costs and the amount of funding contributions will be dependent on various factors, including investment returns achieved on plan assets, the level of interest rates, changes to plan design and actuarial assumptions, actual plan experience versus projections and amendments to pension plan regulations and legislation. Increases in the level of required plan funding are not expected to have a material impact on the Company's liquidity.

Bruce Power

Bruce A has signed commitments to third-party suppliers related to refurbishing and restarting Units 1 and 2. TransCanada's share of these signed commitments, which extend over a two year period ending December 31, 2011, totals $295 million.

Aboriginal Pipeline Group

Under its agreement with the APG, TransCanada agreed to finance the APG's one-third share of the MGP project's predevelopment costs. These costs are currently forecast to be between $150 million and $200 million, on a cumulative basis, depending on the pace of project development. As at December 31, 2009, the Company had advanced $143 million of this total. This agreement is discussed further in the Pipelines – Opportunities and Developments section of this MD&A.

Contingencies

TransCanada is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2009, the Company had recorded liabilities of approximately $67 million representing its estimate of the amount it expects to expend to remediate certain sites. However, additional liabilities may be incurred as more assessments occur and remediation efforts continue.

TransCanada and its subsidiaries are subject to various legal proceedings and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

Guarantees

TransCanada, Cameco Corporation and BPC have severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, a lease agreement and contractor services. The guarantees have terms ranging from 2018 to perpetuity. In addition, TransCanada and BPC have severally guaranteed one-half of certain contingent financial obligations related to an agreement with the OPA to refurbish and restart Bruce A power generation units. The guarantees were provided as part of the reorganization of Bruce Power in 2005 and have terms ending in 2018 and 2019. In its 2009 decision to renew the operating licenses of Bruce Power, the Canadian Nuclear Safety Commission ordered that it was no longer necessary for the major partners of Bruce Power, including TransCanada, to provide financial assurances to Bruce Power to support its license obligations. TransCanada's share of the potential exposure under the remaining Bruce A and Bruce B guarantees was estimated at December 31, 2009 to be approximately $741 million. The fair value of these Bruce Power guarantees is estimated to be $82 million. The Company's exposure under certain of these guarantees is unlimited.

In addition to the guarantees for Bruce Power, the Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities related primarily to redelivery of natural gas, PPA payments and the payment of liabilities. TransCanada's share of the potential exposure under these guarantees was estimated at December 31, 2009 to range from $351 million to a maximum of $632 million. The fair value of these guarantees is estimated to be $9 million which has been included in deferred amounts. The Company's exposure under certain of these guarantees is unlimited. For certain of these entities, any payments made by TransCanada under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

FINANCIAL RISKS AND FINANCIAL INSTRUMENTS

Risk Management Overview

TransCanada has exposure to market risk, counterparty credit risk and liquidity risk. TransCanada engages in risk management activities with the objective being to protect earnings, cash flow and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure TransCanada's risks and related exposures are in line with the Company's business objectives and risk tolerance. Risks are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by risk management and internal audit personnel. The Board of Directors' Audit Committee oversees how management monitors compliance with risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework. Internal audit personnel assist the Audit Committee in its oversight role by performing regular and ad-hoc reviews of risk management controls and procedures, the results of which are reported to the Audit Committee.

Market Risk

The Company constructs and invests in large infrastructure projects, purchases and sells energy commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. These activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which affect the Company's earnings and the value of the financial instruments it holds.

The Company uses derivatives as part of its overall risk management strategy to manage the exposure to market risk that results from these activities. Derivative contracts used to manage market risk generally consist of the following:

- Forwards and futures contracts – contractual agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future. TransCanada enters into foreign exchange and commodity forwards and futures to mitigate the impact of volatility in foreign exchange rates and commodity prices.
- Swaps – contractual agreements between two parties to exchange streams of payments over time according to specified terms. The Company enters into interest rate, cross-currency and commodity swaps to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.
- Options – contractual agreements to convey the right, but not the obligation, of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. The Company enters into option agreements to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.

Commodity Price Risk

The Company is exposed to commodity price movements as part of its normal business operations, particularly in relation to the prices of electricity, natural gas and oil products. A number of strategies are used to mitigate these exposures, including the following:

- Subject to its overall risk management strategy, the Company commits a significant portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to mitigate price risk in its asset portfolio.
- The Company purchases a portion of the natural gas and oil products required for its power plants or enters into contracts that base the sales price of electricity on the cost of natural gas, effectively locking in a margin. A significant portion of the electricity needed to fulfill the Company's power sales commitments is fulfilled through power generation or purchased through contracts, thereby reducing the Company's exposure to fluctuating commodity prices.

- The Company enters into offsetting or back-to-back positions using derivative financial instruments to manage price risk exposure in power and natural gas commodities created by certain fixed and variable pricing arrangements for different pricing indices and delivery points.

The Company assesses its commodity contracts and derivative instruments used to manage commodity risk to determine the appropriate accounting treatment. Contracts, with the exception of leases, have been assessed to determine whether they or certain aspects of them meet the definition of a derivative. Certain commodity purchase and sale contracts are derivatives but are not within the scope of Canadian Institute of Chartered Accountants (CICA) Handbook Section 3855 "Financial Instruments – Recognition and Measurement", as they were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's expected purchase, sale or usage requirements. Certain other contracts are not within the scope of Section 3855 as they are considered to meet other exemptions.

TransCanada manages its exposure to seasonal natural gas price spreads in its natural gas storage business by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. TransCanada simultaneously enters into a forward purchase of natural gas for injection into storage and an offsetting forward sale of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to natural gas price movements. Fair value adjustments recorded each period on proprietary natural gas inventory in storage and these forward contracts may not be representative of the amounts that will be realized on settlement.

Natural Gas Inventory Price Risk

At December 31, 2009, the fair value of proprietary natural gas inventory in storage, as measured using a weighted average of forward prices for the following four months less selling costs, was $73 million (2008 – $76 million). The change in fair value of proprietary natural gas inventory in storage in 2009 resulted in a net pre-tax unrealized gain of $3 million (2008 – unrealized loss of $7 million; 2007 – nil), which was recorded as an increase to Revenues and Inventories. The net change in fair value of natural gas forward purchase and sales contracts in 2009 resulted in a net pre-tax unrealized loss of $2 million (2008 – unrealized gain of $7 million; 2007 – unrealized gain of $10 million), which was recorded as a decrease in revenues.

Foreign Exchange and Interest Rate Risk

Foreign exchange and interest rate risk is created by fluctuations in the fair value or cash flow of financial instruments due to changes in foreign exchange rates and market interest rates.

A portion of TransCanada's earnings from its Pipelines and Energy segments is generated in U.S. dollars and, as such, movement of the Canadian dollar relative to the U.S. dollar can affect TransCanada's earnings. This foreign exchange impact is offset by certain related debt and financing costs being denominated in U.S. dollars and by the Company's hedging activities. TransCanada currently has a greater exposure to U.S. currency fluctuations than in prior years due to significant growth in its U.S. operations, partially offset by increased levels of U.S. dollar-denominated debt.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to its debt and other U.S. dollar-denominated transactions, and to manage the interest rate exposures of the Canadian Mainline, Alberta System and Foothills operations. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms. These gains and losses are deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers in accordance with the terms of the shipping agreements.

TransCanada has floating interest rate debt, which subjects it to interest rate cash flow risk. The Company uses a combination of interest rate swaps and options to manage its exposure to this risk.

On a consolidated basis, the impact of changes in the U.S. dollar on U.S. Pipelines and Energy earnings is largely offset by the impact on U.S. dollar interest expense. The resultant net exposure is managed using derivatives, effectively reducing the Company's exposure to changes in foreign exchange rates.

Net Investment in Self-Sustaining Foreign Operations

The Company hedges its net investment in self-sustaining foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, forward foreign exchange contracts and foreign exchange options. At December 31, 2009, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $7.9 billion (US$7.6 billion) (2008 – $7.2 billion (US$5.9 billion)) and a fair value of $9.8 billion (US$9.3 billion) (2008 – $5.9 billion (US$4.8 billion)). At December 31, 2009, $96 million was included in Intangibles and Other Assets (2008 – $254 million in Deferred Amounts) for the fair value of the forwards, swaps and options used to hedge the Company's net U.S. dollar investment in foreign operations.

The fair values and notional or principal amounts for the derivatives designated as a net investment hedge were as follows:

Asset/(Liability)
December 31 *(millions of dollars)*

	2009		2008	
	Fair Value[(1)]	**Notional or Principal Amount**	Fair Value[(1)]	Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2010 to 2014)	**86**	**U.S. 1,850**	(218)	U.S. 1,650
U.S. dollar forward foreign exchange contracts (maturing 2010)	**9**	**U.S. 765**	(42)	U.S. 2,152
U.S. dollar options (maturing 2010)	**1**	**U.S. 100**	6	U.S. 300
	96	**U.S. 2,715**	(254)	U.S. 4,102

(1) Fair values equal carrying values.

VaR Analysis

TransCanada uses a Value-at-Risk (VaR) methodology to estimate the potential impact resulting from its exposure to market risk on its open liquid positions. VaR estimates the potential change in pre-tax earnings over a given holding period for a specified confidence level. The VaR number calculated and used by TransCanada reflects a 95 per cent probability that the daily change resulting from normal market fluctuations in its open liquid positions will not exceed the reported VaR. The VaR methodology is a statistically-calculated, probability-based approach that takes into consideration market volatilities as well as risk diversification by recognizing offsetting positions and correlations among products and markets. Risks are measured across all products and markets, and risk measures are aggregated to arrive at a single VaR number.

There is currently no uniform industry methodology for estimating VaR. The use of VaR has limitations because it is based on historical correlations and volatilities in commodity prices, interest rates and foreign exchange rates, and assumes that future price movements will follow a statistical distribution. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR.

TransCanada's estimation of VaR includes wholly owned subsidiaries and incorporates relevant risks associated with each market or business unit. The calculation does not include the Pipelines segment as the rate-regulated nature of the pipeline business reduces the impact of market risks. TransCanada's Board of Directors has established a VaR limit, which is monitored on an ongoing basis as part of the Company's risk management policy. TransCanada's consolidated

VaR was $12 million at December 31, 2009 (2008 – $23 million). The decline from December 31, 2008 was primarily due to decreased prices and lower open positions in the U.S. power portfolio.

Counterparty Credit Risk

Counterparty credit risk represents the financial loss the Company would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of its contracts with the Company.

Counterparty credit risk is managed through established credit management techniques, including conducting financial and other assessments to establish and monitor a counterparty's creditworthiness, setting exposure limits, monitoring exposures against these limits, using master netting arrangements and obtaining financial assurances where warranted. In general, financial assurances include guarantees, letters of credit and cash. The Company monitors and manages its concentration of counterparty credit risk on an ongoing basis. The Company believes these measures minimize its counterparty credit risk but there is no certainty that they will protect it against all material losses.

TransCanada's maximum counterparty credit exposure with respect to financial instruments at the balance sheet date consisted primarily of non-derivative financial assets such as accounts receivable, loans and notes receivable, as well as the fair value of derivative assets. Within these balances, the Company does not have significant concentrations of counterparty credit risk with any individual counterparties and the majority of counterparty credit exposure is with counterparties who are investment grade. At December 31, 2009, there were no significant amounts past due or impaired.

TransCanada has significant credit and performance exposures to financial institutions as they provide committed credit lines and cash deposit facilities, critical liquidity in the foreign exchange derivative, interest rate derivative and energy wholesale markets, and letters of credit to mitigate TransCanada's exposure to non-creditworthy counterparties.

As a level of uncertainty continues to exist in the global financial markets, TransCanada continues to closely monitor and reassess the creditworthiness of its counterparties. This has resulted in TransCanada reducing or mitigating its exposure to certain counterparties where it was deemed warranted and permitted under contractual terms. As part of its ongoing operations, TransCanada must balance its market and counterparty credit risks when making business decisions.

Certain subsidiaries of Calpine filed for bankruptcy protection in both Canada and the U.S. in 2005. Gas Transmission Northwest Corporation (GTNC) and Portland reached agreements with Calpine for allowed unsecured claims in the Calpine bankruptcy. In February 2008, GTNC and Portland received initial distributions of 9.4 million common shares and 6.1 million common shares, respectively, of Calpine, which represented approximately 85 per cent of their agreed-upon claims. In 2008, these shares were sold into the open market and resulted in total pre-tax gains of $279 million. Claims by NGTL and Foothills Pipe Lines (South B.C.) Ltd. for $32 million and $44 million, respectively, were received in cash in January 2008 and were passed on to shippers on these systems in 2008 and 2009.

Liquidity Risk

Liquidity risk is the risk that TransCanada will not be able to meet its financial obligations when due. The Company's approach to managing liquidity risk is to ensure that, under both normal and stressed conditions, it always has sufficient cash and credit facilities to meet its obligations when due without incurring unacceptable losses or damage to the Company's reputation.

Management continuously forecasts cash flows for a period of 12 months to identify financing requirements. These requirements are then managed through a combination of committed and demand credit facilities and access to capital markets, as discussed under the heading Capital Management below.

At December 31, 2009, the Company had committed revolving bank lines of US$1.0 billion, $2.0 billion, US$1.0 billion and US$300 million maturing November 2010, December 2012, December 2012 and February 2013, respectively. At December 31, 2009, the US$300 million facility was fully drawn and no draws were made on any of the other facilities. The Company has maintained continuous access to the Canadian commercial paper market on competitive terms.

The Company has access to capital markets under the following prospectuses:

- In December 2009, TCPL filed a US$4.0 billion debt base shelf prospectus qualifying for the issuance of up to US$4.0 billion of debt securities in the U.S. At December 31, 2009, no amounts were issued under the base shelf prospectus.
- In September 2009, TransCanada filed a $3.0 billion base shelf prospectus qualifying for the issuance of up to $3.0 billion of equity instruments in Canada and the U.S. until October 2011. At December 31, 2009, the Company had $2.45 billion available under the base shelf prospectus.
- In April 2009, TCPL filed a $2.0 billion Medium-Term Notes base shelf prospectus in Canada. At December 31, 2009, no amounts were issued under this base shelf prospectus.

Capital Management

The primary objective of capital management is to ensure TransCanada has strong credit ratings to support its businesses and maximize shareholder value. In 2009, the overall objective and policy for managing capital remained unchanged from the prior year.

TransCanada manages its capital structure in a manner consistent with the risk characteristics of the underlying assets. The Company's management considers its capital structure to consist of net debt, non-controlling interests and shareholders' equity. Net debt is comprised of notes payable, long-term debt and junior subordinated notes less cash and cash equivalents. Net debt only includes obligations that the Company controls and manages. Consequently, it does not include cash and cash equivalents, notes payable and long-term debt of TransCanada's joint ventures. The Company's capital structure was as follows:

December 31 *(millions of dollars)*	**2009**	2008
Notes payable	**1,678**	1,685
Long-term debt	**16,664**	16,154
Junior subordinated notes	**1,036**	1,213
Cash and cash equivalents	**(896)**	(1,117)
Net debt	**18,482**	17,935
Non-controlling interests	**1,174**	1,194
Shareholders' equity	**15,759**	12,898
Total equity	**16,933**	14,092
Total capital	**35,415**	32,027

Fair Values

Certain financial instruments included in cash and cash equivalents, accounts receivable, intangibles and other assets, notes payable, accounts payable, accrued interest and deferred amounts have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity. The fair value of foreign exchange and interest rate derivatives has been calculated using year-end market rates. The fair value of power, natural gas and oil products derivatives has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques are used. Credit risk has been taken into consideration when calculating the fair value of derivatives.

The fair value of the Company's long-term debt was estimated based on quoted market prices for the same or similar debt instruments and, when such information was not available, was estimated by discounting future payments of interest and principal at estimated interest rates that were made available to the Company.

Non-Derivative Financial Instruments Summary
The carrying and fair values of non-derivative financial instruments were as follows:

December 31 *(millions of dollars)*	**2009**		2008	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial Assets[1]				
Cash and cash equivalents	**997**	**997**	1,308	1,308
Accounts receivable, intangibles and other assets[2][3]	**1,432**	**1,483**	1,427	1,427
Available-for-sale assets[2]	**23**	**23**	27	27
	2,452	**2,503**	2,762	2,762
Financial Liabilities[1][3]				
Notes payable	**1,687**	**1,687**	1,702	1,702
Accounts payable and deferred amounts[4]	**1,538**	**1,538**	1,372	1,372
Accrued interest	**377**	**377**	359	359
Long-term debt	**16,664**	**19,377**	16,154	15,337
Junior subordinated notes	**1,036**	**976**	1,213	815
Long-term debt of joint ventures	**965**	**1,025**	1,076	1,052
	22,267	**24,980**	21,876	20,637

(1) Consolidated net income in 2009 included $6 million (2008 – $15 million) for fair value adjustments related to interest rate swap agreements on US$250 million (2008 – US$200 million and $50 million) of long-term debt. There were no other unrealized gains or losses from fair value adjustments to these financial instruments.

(2) At December 31, 2009, the Consolidated Balance Sheet included financial assets of $966 million (2008 – $1,280 million) in accounts receivable and $489 million (2008 – $174 million) in intangibles and other assets.

(3) Recorded at amortized cost, except for certain long-term debt and notes receivable which are adjusted to fair value.

(4) At December 31, 2009, the Consolidated Balance Sheet included financial liabilities of $1,513 million (2008 – $1,350 million) in accounts payable and $25 million (2008 – $22 million) in deferred amounts.

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2009 is as follows:

December 31 *(all amounts in millions unless otherwise indicated)*	2009				
	Power	Natural Gas	Oil Products	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]					
Fair Values[2]					
Assets	$150	$107	$5	$–	$25
Liabilities	$(98)	$(112)	$(5)	$(66)	$(68)
Notional Values					
Volumes[3]					
Purchases	15,275	238	180	–	–
Sales	13,185	194	180	–	–
Canadian dollars	–	–	–	–	574
U.S. dollars	–	–	–	U.S. 444	U.S. 1,325
Cross-currency	–	–	–	227/U.S. 157	–
Net unrealized gains/(losses) in the year	$3	$(5)	$1	$3	$27
Net realized gains/(losses) in the year	$70	$(76)	$–	$36	(22)
Maturity dates	2010-2015	2010-2014	2010	2010-2012	2010-2018
Derivative Financial Instruments in Hedging Relationships[4][5]					
Fair Values[2]					
Assets	$175	$2	$–	$–	$15
Liabilities	$(148)	$(22)	$–	$(43)	$(50)
Notional Values					
Volumes[3]					
Purchases	13,641	33	–	–	–
Sales	14,311	–	–	–	–
U.S. dollars	–	–	–	U.S. 120	U.S. 1,825
Cross-currency	–	–	–	136/U.S. 100	–
Net realized gains/(losses) in the year	$156	$(29)	$–	$–	$(37)
Maturity dates	2010-2015	2010-2014	–	2010-2014	2010-2020

(1) All derivative financial instruments in the held-for-trading classification have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

(2) Fair values equal carrying values.

(3) Volumes for power, natural gas and oil products derivatives are in GWh, Bcf and thousands of barrels, respectively.

(4) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $4 million and a notional amount of US$150 million. Net realized gains on fair value hedges for December 31, 2009 were $4 million and were included in interest expense. In 2009, the Company did not record any amounts in net income related to ineffectiveness for fair value hedges.

(5) In 2009, net income included losses of $5 million for the changes in fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2009, there were no gains or losses included in net income for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

The anticipated timing of settlement of the derivative contracts assumes constant commodity prices, interest rates and foreign exchange rates from December 31, 2009. Settlements will vary based on the actual value of these factors at the date of settlement. The anticipated timing of settlement of these contracts is as follows:

Year ended December 31 *(millions of dollars)*	Total	2010	2011 and 2012	2013 and 2014	2015 and Thereafter
Derivative financial instruments held for trading					
Assets	287	201	73	11	2
Liabilities	(349)	(233)	(85)	(27)	(4)
Derivative financial instruments in hedging relationships					
Assets	288	142	106	35	5
Liabilities	(263)	(106)	(89)	(66)	(2)
	(37)	4	5	(47)	1

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2008 is as follows:

December 31 *(all amounts in millions unless otherwise indicated)*	2008 Power	2008 Natural Gas	2008 Oil Products	2008 Foreign Exchange	2008 Interest
Derivative Financial Instruments Held for Trading					
Fair Values[1]					
Assets	$132	$144	$10	$41	$57
Liabilities	$(82)	$(150)	$(10)	$(55)	$(117)
Notional Values					
Volumes[2]					
Purchases	4,035	172	410	–	–
Sales	5,491	162	252	–	–
Canadian dollars	–	–	–	–	1,016
U.S. dollars	–	–	–	U.S. 479	U.S. 1,575
Japanese yen (in billions)	–	–	–	JPY 4.3	–
Cross-currency	–	–	–	227/U.S. 157	–
Net unrealized gains/(losses) in the year	$24	$(23)	$1	$(9)	$(61)
Net realized gains/(losses) in the year	$23	$(2)	$1	$6	$13
Maturity dates	2009-2014	2009-2011	2009	2009-2012	2009-2018
Derivative Financial Instruments in Hedging Relationships[3][4]					
Fair Values[1]					
Assets	$115	$–	$–	$2	$8
Liabilities	$(160)	$(18)	$–	$(24)	$(122)
Notional Values					
Volumes[2]					
Purchases	8,926	9	–	–	–
Sales	13,113	–	–	–	–
Canadian dollars	–	–	–	–	50
U.S. dollars	–	–	–	U.S. 15	U.S. 1,475
Cross-currency	–	–	–	136/U.S. 100	–
Net realized (losses)/gains in the year	$(56)	$15	$–	$–	$(10)
Maturity dates	2009-2014	2009-2011	–	2009-2013	2009-2019

(1) Fair values equal carrying values.

(2) Volumes for power, natural gas and oil products derivatives are in GWh, Bcf and thousands of barrels, respectively.

(3) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $8 million and notional amounts of $50 million and US$50 million. Net realized gains on fair value hedges at December 31, 2008 were $1 million. In 2008, the Company did not record any amounts in net income related to ineffectiveness for fair value hedges.

(4) In 2008, net income included losses of $6 million for changes in fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2008, there were no gains or losses included in net income for discontinued cash flow hedges.

A 10 per cent increase or 10 per cent decrease in commodity prices, with all other variables held constant, would cause an $18 million decrease or an $18 million increase, respectively, in the fair value of derivative financial instruments outstanding as at December 31, 2009.

A 100 basis points increase or 100 basis points decrease in the letter of credit rate, with all other variables held constant, would cause a $6 million increase or a $6 million decrease, respectively, in the fair value of guarantee liabilities outstanding as at December 31, 2009. Similarly, the effect of a 100 basis points increase or 100 basis points decrease in the discount rate on the fair value of guarantee liabilities outstanding as at December 31, 2009 would cause a $2 million decrease in the liability or a $2 million increase in the liability, respectively.

Balance Sheet Presentation of Derivative Financial Instruments
The fair value of the derivative financial instruments in the Company's Balance Sheet was as follows:

December 31 *(millions of dollars)*	**2009**	2008
Current		
Other current assets	**315**	318
Accounts payable	**(340)**	(298)
Long-term		
Intangibles and other assets	**260**	191
Deferred amounts	**(272)**	(694)

OTHER RISKS

Development Projects and Acquisitions
TransCanada continues to focus on growing its Pipelines and Energy operations through greenfield development projects and acquisitions. TransCanada capitalizes costs incurred on certain of its projects during the development period prior to construction when the project meets specific criteria and is expected to proceed through to completion. The related capital costs of a project that does not proceed through to completion are expensed at the time it is discontinued. There is a risk with respect to TransCanada's acquisition of assets and operations that certain commercial opportunities and operational synergies may not materialize as expected and would subsequently be subject to an impairment writedown.

Health, Safety and Environment Risk Management
Health, safety and environment (HS&E) are top priorities in all of TransCanada's operations and activities in these areas are guided by the Company's HS&E Commitment Statement. The Commitment Statement outlines guiding principles for a safe and healthy environment for TransCanada's employees, contractors and the public, and for TransCanada's commitment to protect the environment. All employees are held responsible and accountable for HS&E performance. The Company is committed to being an industry leader in conducting its business so that it meets or exceeds all applicable laws and regulations, and minimizes risk to people and the environment. The Company is committed to tracking and improving its HS&E performance, and to promoting safety on and off the job in the belief that all occupational injuries and illnesses are preventable. TransCanada endeavours to do business with companies and contractors that share its perspective on HS&E performance and to influence them to improve their collective performance. TransCanada is committed to respecting the diverse environments and cultures in which it operates and to supporting open communication with the public, policy makers, scientists and public interest groups.

TransCanada is committed to ensuring compliance with its internal policies and legislated requirements. The HS&E Committee of TransCanada's Board of Directors monitors compliance with the Company's HS&E corporate policy through regular reporting. TransCanada's HS&E management system is modeled on the International Organization for

Standardization's (ISO) standard for environmental management systems, ISO 14001, and focuses resources on the areas of significant risk to the organization's HS&E business activities. Management is informed regularly of all important HS&E operational issues and initiatives through formal reporting processes. TransCanada's HS&E management system and performance are assessed by an independent outside firm every three years. The most recent assessment occurred in December 2009 and did not identify any material issues. The HS&E management system is subject to ongoing internal review to ensure that it remains effective as circumstances change.

In 2009, employee and contractor health and safety performance continued to be a top priority. TransCanada's objective is a health and safety performance consistent with top quartile companies in its sectors. Overall, the Company's safety frequency rates in 2009 continued to be better than most industry benchmarks.

The safety and integrity of the Company's existing and newly developed infrastructure also continued to be top priorities. All new assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are not brought into service until all necessary requirements are satisfied. The Company expects to spend approximately $181 million in 2010 for pipeline integrity on its wholly owned pipelines, which is $10 million higher than in 2009 primarily due to increased levels of in-line pipeline inspection on all systems. Under the approved regulatory models in Canada, pipeline integrity expenditures on NEB regulated pipelines are treated on a flow-through basis and, as a result, have no impact on TransCanada's earnings. Under the Keystone contracts, pipeline integrity expenditures are recovered through the tolling mechanism and, as a result, have no impact on TransCanada's earnings. Expenditures for GTN may also be recovered through a cost recovery mechanism in its rates. TransCanada's pipeline safety record in 2009 continued to be above industry benchmarks. TransCanada experienced three pipeline breaks in 2009. The first occurred in a remote part of northern Alberta. The other two occurred in rural parts of northern Ontario. The breaks resulted in minimal impact with no injuries and only minor property damage in one of the incidents. All three incidents were subject to a Level 3 investigation by the Transportation Safety Board of Canada. Spending associated with public safety on the Energy assets is focused primarily on the Company's hydro dams and associated equipment, and is consistent with previous years.

Environment

TransCanada's facilities are subject to various federal, provincial, state and local statutes and regulations, including requirements to establish compliance and remediation obligations. Compliance obligations can result in significant costs associated with installing and maintaining pollution controls, fines and penalties resulting from any failure to comply, and potential limitations on operations. Remediation obligations can result in significant costs associated with the investigation and remediation of contaminated properties, some of which have been designated as Superfund sites by the U.S. Environmental Protection Agency under the *Comprehensive Environmental Response, Compensation and Liability Act*, and with damage claims arising out of the contamination of properties. It is not possible for the Company to estimate the amount and timing of all future expenditures related to environmental matters due to:

- Uncertainties in estimating pollution control and clean-up costs, including at sites where only preliminary site investigation or agreements have been completed;
- the potential discovery of new sites or additional information at existing sites;
- the uncertainty in quantifying liability under environmental laws that impose joint and several liability on all potentially responsible parties;
- the evolving nature of environmental laws and regulations, including the interpretation and enforcement thereof; and
- the potential for litigation on existing or discontinued assets.

Environmental risks from TransCanada's operating facilities typically include: air emissions, such as nitrogen oxides, particulate matter and greenhouse gases; potential impacts on land, including land reclamation or restoration following construction; the use, storage or release of chemicals or hydrocarbons; the generation, handling and disposal of wastes and hazardous wastes; and water impacts such as uncontrolled water discharge. Environmental controls including physical design, programs, procedures and processes are in place to effectively manage these risks. TransCanada has ongoing inspection programs designed to keep all of its facilities in compliance with environmental requirements and the Company is confident that its systems are in material compliance with the applicable requirements.

In 2009, TransCanada conducted environmental risk assessments and remediation work, as well as various retirement, reclamation and restoration activities on its Canadian and U.S. facilities. At December 31, 2009, TransCanada had recorded liabilities of approximately $91 million (2008 – $86 million) for remediation obligations and compliance costs associated with greenhouse gas (GHG) legislation. The Company believes it has considered all necessary contingencies and established appropriate reserves for environmental liabilities. However, there is the risk that unforeseen matters may arise requiring the Company to set aside additional amounts.

TransCanada is not aware of any material outstanding orders, claims or lawsuits against the Company in relation to the release or discharge of any material into the environment or in connection with environmental protection.

North American climate change policy continues to evolve at regional and national levels. While recent political and economic events may significantly affect the scope and timing of new measures that are put in place, TransCanada anticipates that most of the Company's facilities in Canada and the U.S. are or will be captured under federal or regional climate change regulations to manage industrial GHG emissions.

In 2009, the Company owned assets in three Canadian provinces where regulations exist to address industrial GHG emissions. TransCanada has put in place procedures to address these regulations.

In Alberta, under the Specified Gas Emitters Regulation, industrial facilities are required to reduce GHG emissions intensities by 12 per cent, effective July 2007. TransCanada's Alberta-based facilities are subject to this regulation, as are the Sundance and Sheerness coal-fired power facilities with which TransCanada has PPAs. As an alternative to reducing emissions intensities, compliance can be achieved through the retirement of offsets or payments to a technology fund at a cost of $15 per tonne of carbon dioxide (CO_2) in excess of the mandated reduction. A program is in place to manage the compliance costs incurred by these assets as a result of the regulation. Compliance costs on the Alberta System are recovered through tolls paid by customers. Recovery of compliance costs at the Company's power generation facilities in Alberta is dependent ultimately on market prices for electricity. TransCanada has estimated and recorded costs of $17 million for 2009. These costs will be finalized when compliance reports are submitted in March 2010.

The hydrocarbon royalty in Québec is collected by the natural gas distributor on behalf of the Québec government through a green fund contribution charge on gas consumed. In 2009, the cost pertaining to the Bécancour facility arising from the hydrocarbon royalty was less than $1 million as a result of an agreement between TransCanada and Hydro-Québec to temporarily suspend the facility's power generation. The cost is expected to increase when the plant returns to service.

B.C.'s carbon tax, which came into effect in mid-2008, applies to CO_2 emissions arising from fossil fuel combustion. Compliance costs for fuel combustion at the Company's compressor and meter stations in B.C. are recovered through tolls paid by customers. Costs related to the carbon tax in 2009 were $3 million. The cost per tonne of CO_2 was $15 in 2009 and will increase to $20 per tonne and $25 per tonne in 2010 and 2011, respectively.

TransCanada has assets located in provinces where members of the Western Climate Initiative (WCI) have drafted regulations that apply to industrial GHG emitters. The Canadian WCI members include B.C., Manitoba, Ontario and Québec. The draft climate change strategies are expected to come into effect in 2012 and are expected to affect TransCanada's pipeline and power facilities. The details of how these provincial programs will align with the Canadian government's climate change policies remain uncertain.

Seven western U.S. states, along with the four Canadian provinces discussed above, are focused on the implementation of a cap and trade program under the WCI. Members of the WCI have set a GHG emission reduction target of 15 per cent below 2005 levels by 2020. California, a WCI founding member, has released draft cap and trade regulations that, if enacted, are anticipated to have an impact on the Company's pipeline assets in the state. The financial implications to TransCanada are not expected to be material. Under the current form of draft regulations in Washington and Oregon it is expected that there will not be a significant cost of compliance in these states. TransCanada will continue to monitor these developments.

The Canadian government has continued to express interest in pursuing a harmonized continental climate change strategy. In January 2010, Environment Canada presented a revised target to the United Nations Framework Convention on Climate Change as part of its submission for the *Copenhagen Accord*. The submitted target represents a 17 per cent reduction in GHG emissions by 2020 relative to 2005 levels. The submission states that Canada will align with the final economy-wide emissions targets of the U.S. in enacted legislation. The Company expects that pipeline and power generation emissions will be subject to reduction targets for industrial emitters.

Emission allowances or credits purchased for compliance are recorded on the balance sheet at historical cost and expensed when they are retired. Compliance payments are expensed when incurred. Allowances granted to or internally generated by TransCanada are not attributed a value for accounting purposes. When required, TransCanada accrues emission liabilities on the balance sheet upon the generation or sale of power using the best estimate of the amount required to settle the obligation. Allowances or credits not used for compliance are sold and recorded as revenue. In 2009, costs of compliance and revenues from the sale of allowances were not significant.

Northeastern U.S. states that are members of the Regional Greenhouse Gas Initiative (RGGI) implemented a CO_2 cap and trade program for electricity generators effective January 1, 2009. Under the RGGI, both the Ravenswood and OSP power generation facilities will be required to submit allowances by December 31, 2011. TransCanada participated in the quarterly auctions of allowances for Ravenswood and OSP, and incurred related costs of $8 million in 2009. These costs were generally recovered through the power market and the net impact on TransCanada was not significant.

Participants in the *Midwestern Greenhouse Gas Reduction Accord*, which involves six U.S. states and the province of Manitoba, are developing a regional strategy for reducing members' GHG emissions that will include a multi-sector cap and trade mechanism. Draft recommendations have been released but as yet not formally endorsed by participant states and Manitoba.

Climate change is a strategic issue for the U.S. government and federal policy to manage domestic GHG emissions continues to be a priority. The Environmental Protection Agency has released an endangerment finding regarding GHG emissions under the *Clean Air Act*. This finding was to determine whether the six types of GHGs in the atmosphere threaten the health and welfare of current and future generations. The U.S. House of Representatives passed a climate bill in June 2009 and the U.S. Senate is deliberating on a series of climate bills.

TransCanada monitors climate change policy developments and, when warranted, participates in policy discussions. The Company is also continuing its programs to manage GHG emissions from its facilities and to evaluate new processes and technologies that result in improved efficiencies and lower GHG emission rates.

CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S. securities laws. The information is accumulated and communicated to management, including the President and Chief Executive Officer and the Chief Financial Officer, to allow timely decisions regarding required disclosure.

As at December 31, 2009, an evaluation of the effectiveness of TransCanada's disclosure controls and procedures as defined under the rules adopted by the Canadian securities regulatory authorities and by the SEC was carried out under the supervision and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer. Based on this evaluation, the President and Chief Executive Officer and the Chief Financial

Officer concluded that the design and operation of TransCanada's disclosure controls and procedures were effective as at December 31, 2009.

Management's Annual Report on Internal Control over Financial Reporting
Internal control over financial reporting is a process designed by or under the supervision of senior management and effected by the Board of Directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and preparation of consolidated financial statements for external purposes in accordance with Canadian GAAP, including a reconciliation to U.S. GAAP.

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting, no matter how well designed, has inherent limitations and can only provide reasonable assurance with respect to the preparation and fair presentation of published financial statements. Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on this evaluation, management concluded that internal control over financial reporting is effective as at December 31, 2009, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

In 2009, there was no change in TransCanada's internal control over financial reporting that materially affected or is reasonably likely to materially affect TransCanada's internal control over financial reporting.

CEO and CFO Certifications
TransCanada's President and Chief Executive Officer and Chief Financial Officer have filed with the SEC and the Canadian securities regulators certifications regarding the quality of TransCanada's public disclosures relating to its fiscal 2009 reports filed with the SEC and the Canadian securities regulators.

SIGNIFICANT ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

To prepare financial statements that conform with Canadian GAAP, TransCanada is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses, since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgment in making these estimates and assumptions. The Company believes the following accounting policies and estimates require it to make assumptions about highly uncertain matters and changes in these estimates could have a material impact on the Company's financial information.

Regulated Accounting
The Company accounts for the impacts of rate regulation in accordance with GAAP. Three criteria must be met to use these accounting principles:

- The rates for regulated services or activities must be established by or subject to approval by a regulator;
- the regulated rates must be designed to recover the cost of providing the services or products; and
- it must be reasonable to assume that rates set at levels to recover the cost can be charged to and collected from customers in view of the demand for services or products and the level of direct and indirect competition.

The Company's management believes all three of these criteria have been met with respect to each of the regulated natural gas pipelines accounted for using regulated accounting principles. The most significant impact from the use of these accounting principles is that the timing of recognition of certain expenses and revenues in the regulated businesses may differ from that otherwise expected under GAAP in order to appropriately reflect the economic impact of the regulators' decisions regarding the Company's revenues and tolls.

Effective January 1, 2009, the Company's accounting for its future income taxes recorded on rate-regulated operations changed as discussed in the Accounting Changes section of this MD&A.

Financial Instruments and Hedges

Financial Instruments

The Company initially records all financial instruments on the balance sheet at their fair value. Subsequent measurement of the financial instruments is based on their classification. Financial assets are classified into the following categories: held for trading, available for sale, held-to-maturity investments and loans and receivables. Financial liabilities are classified as held for trading or other financial liabilities. The Company does not have any held-to-maturity investments.

Held-for-trading derivative financial assets and liabilities consist of swaps, options, forwards and futures. Commodity held-for-trading financial instruments are initially recorded at their fair value and changes to fair value are included in revenues. Changes in the fair value of interest rate and foreign exchange rate held-for-trading instruments are recorded in interest expense and in interest income and other, respectively.

The available-for-sale classification includes non-derivative financial assets that are designated as available for sale or are not included in the other three classifications. These instruments are accounted for initially at their fair value and changes to fair value are recorded through other comprehensive income. Trade receivables, loans and other receivables with fixed or determinable payments that are not quoted in an active market are classified as "loans and receivables" and are measured at amortized cost using the effective interest method, net of any impairment. Other financial liabilities consist of liabilities not classified as held for trading. Items in this financial instrument category are recognized at amortized cost using the effective interest method.

The recognition of gains and losses on the derivatives for the Canadian Mainline, Alberta System and Foothills exposures is determined through the regulatory process. The gains and losses on derivatives accounted for as part of rate-regulated accounting are deferred in Regulatory Assets or Regulatory Liabilities.

Hedges

The Company applies hedge accounting to its arrangements that qualify for hedge accounting treatment, which include fair value and cash flow hedges, and hedges of foreign currency exposures of net investments in self-sustaining foreign operations. Hedge accounting is discontinued prospectively when the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk. The changes in fair value are recognized in net income. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item, which are also recorded in net income.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income, while any ineffective portion is recognized in net income in the same financial category as the underlying transaction. When hedge accounting is discontinued, the amounts recognized previously in accumulated other comprehensive income are reclassified to net income during the periods when the variability in cash flows of the hedged item affects net income. Gains and losses on derivatives are reclassified immediately to net income from accumulated other comprehensive income when the hedged item is sold or terminated early, or when a hedged anticipated transaction is no longer expected to occur.

The Company also enters into cash flow hedges and fair value hedges for activities subject to rate regulation. Any gains and losses arising from the changes in the fair value of these hedges can be recovered through the tolls charged by the Company. As a result, any gains and losses are deferred as rate-regulated assets or liabilities on behalf of the ratepayers. When the hedges are settled, the realized gains or losses are collected from or refunded to the ratepayers in subsequent years.

In hedging the foreign currency exposure of a net investment in a self-sustaining foreign operation, the effective portion of foreign exchange gains and losses on the hedging instruments is recognized in other comprehensive income and the ineffective portion is recognized in net income. The amounts recognized previously in accumulated other comprehensive income are reclassified to net income in the event the Company settles or otherwise reduces its investment in a foreign operation.

The fair value of financial instruments and hedges, where fair value does not approximate carrying value, is primarily derived from market values adjusted for credit risk, which can fluctuate greatly from period to period. These changes in fair value can result in variability in net income as a result of recording these changes in fair value through earnings. The risks associated with fluctuations to earnings and cash flows for financial instruments and hedges are discussed further in the Risk Management and Financial Instruments section of this MD&A.

Depreciation and Amortization Expense

TransCanada's plant, property and equipment are depreciated on a straight-line basis over their estimated useful lives once they are ready for their intended use. Pipeline and compression equipment are depreciated at annual rates ranging from one per cent to 25 per cent. Metering and other plant equipment are depreciated at various rates. Major power generation and natural gas storage plant, equipment and structures in the Energy business are depreciated on a straight-line basis over estimated service lives at average annual rates ranging from two per cent to ten per cent. Nuclear power generation assets under capital lease are initially recorded at the present value of minimum lease payments at the inception of the lease and amortized on a straight-line basis over the shorter of their useful life and the remaining lease term. Other Energy equipment is depreciated at various rates. Corporate plant, property and equipment are depreciated on a straight-line basis over estimated useful lives at average annual rates ranging from three per cent to 20 per cent.

Depreciation expense in 2009 was $1,319 million (2008 – $1,189 million; 2007 – $1,179 million) and is recorded in Pipelines and Energy. In Pipelines, depreciation rates are approved by regulators when applicable and depreciation expense is recoverable based on the cost of providing the services or products. If regulators permit recovery of depreciation through rates charged to customers, a change in the estimate of the useful lives of plant, property and equipment in the Pipelines segment will have no material impact on TransCanada's net income but will directly affect funds generated from operations.

PPA amortization expense of $58 million was recorded in Energy each year from 2007 through 2009. The initial payment for a PPA is deferred and amortized on a straight-line basis over the term of the contract, with remaining terms ranging from eight years to 11 years.

Impairment of Long-Lived Assets and Goodwill

The Company reviews long-lived assets such as property, plant and equipment, and intangible assets for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows is less than the carrying value of the assets, an impairment loss is recognized for the excess of the carrying value over the fair value of the assets.

Goodwill is tested in the Pipelines and Energy segments for impairment annually, or more frequently if events or changes in circumstances indicate that the asset might be impaired. An initial assessment is made by comparing the fair value of the operations, which includes goodwill, to the book values of each reporting unit. If this fair value is less than book value, an impairment is indicated and a second test is performed to measure the amount of the impairment. In the second test, the implied fair value of the goodwill is calculated by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of the goodwill exceeds the calculated implied fair value of the goodwill, an impairment charge is recorded.

These valuations are based on management's projections of future cash flows and, therefore, require estimates and assumptions with respect to:

- Discount rates;

- commodity prices;
- market supply and demand assumptions;
- growth opportunities;
- output levels;
- competition from other companies; and
- regulatory changes.

Significant changes in these assumptions could affect the Company's need to record an impairment charge.

ACCOUNTING CHANGES

CHANGES IN ACCOUNTING POLICIES FOR 2009

Rate-Regulated Operations
Effective January 1, 2009, the temporary exemption was withdrawn from the CICA Handbook Section 1100 "Generally Accepted Accounting Principles", which permitted the recognition and measurement of assets and liabilities arising from rate regulation. In addition, Section 3465 "Income Taxes" was amended to require the recognition of future income tax assets and liabilities for rate-regulated operations. In accordance with the CICA Handbook accounting hierarchy, the Company chose to adopt accounting policies consistent with the U.S. Financial Accounting Standards Board's (FASB) Accounting Standards Codification (ASC) Topic 980 "Regulated Operations". As a result, TransCanada retained its current method of accounting for its rate-regulated operations, except that the Company is required to recognize future income tax assets and liabilities, instead of using the taxes payable method, and records an offsetting adjustment to regulatory assets and liabilities. As a result of adopting this accounting change, additional future income tax liabilities and a regulatory asset in the amount of $1.4 billion were recorded January 1, 2009 in each of future income taxes and regulatory assets, respectively.

Adjustments to the 2009 financial statements have been made in accordance with the transitional provisions for Section 3465, which required a cumulative adjustment in the current period to future income taxes and regulatory assets. Restatement of prior periods' financial statements was not permitted under Section 3465.

Goodwill and Intangible Assets
Effective January 1, 2009, the Company adopted CICA Handbook Section 3064 "Goodwill and Intangible Assets", which replaced Section 3062 "Goodwill and Other Intangible Assets". Section 3064 gives guidance on the recognition of intangible assets and on the recognition and measurement of internally developed intangible assets. In addition, Section 3450 "Research and Development Costs" was withdrawn from the CICA Handbook. Adopting this accounting change did not have a material effect on the Company's financial statements.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities
Effective January 1, 2009, the Company adopted the accounting provisions of Emerging Issues Committee (EIC) Abstract EIC 173 "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". Under EIC 173, an entity's own credit risk and the credit risk of its counterparties are taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments. Adopting this accounting change did not have a material effect on the Company's financial statements.

FUTURE ACCOUNTING CHANGES

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests
CICA Handbook Section 1582 "Business Combinations" is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of

additional assets and liabilities, and increased disclosure. Adopting the standard is expected to have a material effect on the way the Company accounts for future business combinations. Entities adopting Section 1582 will also be required to adopt CICA Handbook Sections 1601 "Consolidated Financial Statements" and 1602 "Non-Controlling Interests". These standards will require non-controlling interests to be presented as part of shareholders' equity on the balance sheet. In addition, the income statement of the controlling parent will include 100 per cent of the subsidiary's results and present the allocation between the controlling and non-controlling interests. These standards will be effective January 1, 2011, with early adoption permitted. The changes resulting from adopting Section 1582 will be applied prospectively and the changes from adopting Sections 1601 and 1602 will be applied retrospectively.

International Financial Reporting Standards

The CICA's Accounting Standards Board announced that Canadian publicly accountable enterprises are required to adopt IFRS, as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. Effective January 1, 2011, the Company will begin reporting under IFRS.

TransCanada's conversion plan includes obtaining skilled people, providing education and training, analyzing the impact on TransCanada of key differences between GAAP and IFRS, and developing and executing a phased approach to conversion and implementation. The current status of key elements of TransCanada's conversion project is as follows:

Resources and Training

TransCanada has established an IFRS project team to support the conversion effort. The team conducts technical research and provides issue identification, training, work group leadership, policy recommendations and implementation support. The project team is led by a multi-disciplinary Steering Committee that provides directional leadership for the conversion project and assists in developing accounting policy recommendations. Management also updates the Audit Committee on the progress of the IFRS project at each Audit Committee meeting.

TransCanada's IFRS training, which began in 2008, includes project awareness sessions, an annual comprehensive IFRS immersion course, topic specific courses and systems training sessions. Throughout the project, IFRS training is being provided on an ongoing basis to TransCanada staff and directors affected by the conversion to ensure they are knowledgeable about new IFRS developments.

Analysis of Differences Between IFRS and GAAP

TransCanada's conversion project is being executed using a risk-based methodology focusing on the significant differences between GAAP and IFRS. A high-level diagnostic was completed in 2008 outlining the significant differences and rating each difference based on its expected level of significance to TransCanada. In making this assessment, the technical accounting complexity, number of policy choices, estimated need for conversion resources and impact on systems were considered. The project team continues to assess the differences between GAAP and IFRS and their significance to the Company.

The differences between GAAP and IFRS that have been identified as significant to the Company are explained below. Several of the IFRS standards that are expected to be applicable to TransCanada are in the process of being amended by the IASB. Amendments to existing standards are expected to continue until the January 1, 2011 effective date. TransCanada actively monitors the IASB's schedule of projects, giving consideration to any proposed changes, where applicable, in its assessment of differences between IFRS and GAAP. As a result of proposed changes to certain IFRS, together with the current stage of the Company's IFRS project, TransCanada cannot reasonably quantify the full impact that adopting IFRS will have on its financial position and future results.

Rate-Regulated Activities

Under GAAP, TransCanada currently follows specific accounting policies unique to a rate-regulated business. In July 2009, the IASB issued an Exposure Draft "Rate-Regulated Activities". Under the Exposure Draft, regulatory assets and regulatory liabilities will represent the expected present values of future revenues that are expected to be recovered from or refunded to customers. Under GAAP, the Company measures these regulatory assets and regulatory liabilities on a historical cost basis in respect of future revenues that are expected to be recovered from or refunded to customers.

The Exposure Draft also outlines certain criteria an entity must meet to be within the scope of the new standard. The Company continues to assess the impact of developments regarding this exposure draft, as they could have a significant effect on TransCanada's balance sheet and could result in increased income volatility.

Plant, Property and Equipment
Under GAAP, items of plant, property and equipment are depreciated on a straight-line basis over their estimated service lives. Under IFRS, significant components of the same items of plant, property and equipment will be separately identified and depreciated over their respective estimated service life.

Joint Ventures
Under GAAP, TransCanada proportionately consolidates its share of the accounts of joint ventures in which the Company is able to exercise joint control and uses the equity method of accounting for investments over which the Company is able to exercise significant influence.

The IASB issued an Exposure Draft, which is expected to be effective in 2011, under which TransCanada would use the equity method of accounting for joint ventures in which the Company is able to exercise joint control or significant influence, but not sole control. For joint operations in which the Company is able to exercise joint control, TransCanada would record its proportionate share of the assets, liabilities and related revenues and expenses, as well as expenses or liabilities the Company would incur directly on behalf of the assets.

Provisions
Under GAAP, the scope and timing of asset retirements related to regulated natural gas pipelines and hydroelectric power plants is uncertain. As a result, the Company has not recorded an amount for asset retirement obligations related to these assets with the exception of certain abandoned facilities.

Under IFRS, TransCanada would be required to record obligations relating to the retirement of its regulated pipelines where a legal, contractual or constructive obligation currently exists. The Company is assessing its ability to reliably estimate the cost to abandon these assets in the future, where applicable.

Employee Benefits
Under GAAP, past service costs relating to the Company's defined benefit pension plans are recognized over the expected average remaining service life of the employees. Under IFRS, past service costs would be recognized on a straight-line basis over the average remaining vesting period.

Under GAAP, actuarial gains and losses are deferred and amortized using a "corridor" approach. Under IFRS, there are three alternatives for recognizing actuarial gains and losses. These gains or losses can be deferred and amortized subject to certain provisions that differ slightly from GAAP, recognized in profit and loss in the period they are incurred or recognized in other comprehensive income in the period they are incurred. The Company is currently assessing the IFRS alternatives.

Leases
Under GAAP and IFRS, leases that transfer to the Company substantially all the risks and rewards incidental to ownership of the leased item are capitalized at the commencement of the lease term. GAAP prescribes specific thresholds for evaluating whether substantially all the risks and rewards incidental to ownership of the leased item are transferred, while IFRS does not contain such specific thresholds. The Company is currently assessing its lease contracts, including contingent lease payments, under IFRS.

Financial Instruments
Under GAAP, contracts that meet specific scope exemptions or do not meet the definition of a derivative as they do not have a specified notional amount, are not subject to the recognition and measurement criteria for financial instruments. The Company is currently assessing these contracts to determine whether they are subject to IFRS recognition and measurement criteria for financial instruments.

Impairment of Non-Current Assets
The Company reviews non-current assets, such as plant, property and equipment and intangible assets with a definite, useful life, for indicators of impairment at each reporting date. Tests for impairment are performed if there is an indication that the carrying value of the assets may not be recoverable.

The method of determining a potential impairment loss is slightly different under GAAP than under IFRS and the Company is assessing the impact of the difference on TransCanada.

Impairment of Goodwill
Under GAAP, an initial impairment assessment of goodwill is made by comparing the fair value of the operations, which includes goodwill, to the book values of each reporting unit. If the fair value is less than the book value, an impairment is indicated and a second test is performed to measure the amount of the impairment. In the second test, the implied fair value of the goodwill is calculated by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of the goodwill exceeds the calculated implied fair value of the goodwill, an impairment charge is recorded. Under IFRS, for the purposes of impairment testing, goodwill acquired in a business combination is allocated to cash-generating units that are expected to benefit from the synergies of the combination. An impairment loss is recognized when the recoverable amount of the cash-generating unit is less than the carrying amount, including goodwill.

Conversion Implementation
During the conversion implementation phase, TransCanada will continue to execute required changes to its information systems and business processes, disclosure controls and internal controls over financial reporting. Required changes continue to be identified on a concurrent basis with the Company's analysis of significant GAAP differences. TransCanada is also assessing the impact of transitioning to IFRS on its financial statement presentation and disclosures. The Company is monitoring and updating the effect of IFRS on its internal controls over financial reporting and does not expect any significant obstacles.

Information systems, including information technology systems and computer software, are being changed to accommodate IFRS. TransCanada's accounting system has been expanded to enable the production of multiple financial statements based on reporting under both GAAP and IFRS, facilitating the requirement in 2010 to report GAAP financial information while tracking IFRS financial information. Other information system changes include allowing for the capture of new data, creation and deletion of accounts, modifications to existing systems relating to calculations, consolidations, models and reports, and other revisions to accounting software to accommodate IFRS accounting and reporting requirements.

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA[1]

(unaudited) (millions of dollars except per share amounts)	2009 Fourth	Third	Second	First
Revenues	2,206	2,253	2,127	2,380
Net Income	387	345	314	334
Share Statistics				
Net income per share – basic and diluted	$0.56	$0.50	$0.50	$0.54
Dividend declared per common share	$0.38	$0.38	$0.38	$0.38

(unaudited) (millions of dollars except per share amounts)	2008 Fourth	Third	Second	First
Revenues	2,332	2,137	2,017	2,133
Net Income	277	390	324	449
Share Statistics				
Net income per share – basic	$0.47	$0.67	$0.58	$0.83
Net income per share – diluted	$0.46	$0.67	$0.58	$0.83
Dividend declared per common share	$0.36	$0.36	$0.36	$0.36

(1) The selected quarterly consolidated financial data has been prepared in accordance with GAAP.

Factors Impacting Quarterly Financial Information

In Pipelines, which consists primarily of the Company's investments in regulated pipelines and regulated natural gas storage facilities, annual revenues and net income fluctuate over the long term based on regulators' decisions and negotiated settlements with shippers. Generally, quarter-over-quarter revenues and net income during any particular fiscal year remain relatively stable with fluctuations resulting from adjustments being recorded due to regulatory decisions and negotiated settlements with shippers, seasonal fluctuations in short-term throughput volumes on U.S. pipelines, acquisitions and divestitures, and developments outside of the normal course of operations.

In Energy, which consists primarily of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities, quarter-over-quarter revenues and net income are affected by seasonal weather conditions, customer demand, market prices, capacity payments, planned and unplanned plant outages, acquisitions and divestitures, certain fair value adjustments and developments outside of the normal course of operations.

Significant developments that impacted EBIT and net income in 2009 and 2008 were as follows:

- ***Fourth quarter 2009*** Pipelines EBIT included a dilution gain of $29 million pre-tax ($18 million after tax) resulting from TransCanada's reduced ownership interest in PipeLines LP after PipeLines LP issued common units to the public. Energy's EBIT included net unrealized gains of $7 million pre-tax ($5 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Net Income included $30 million of favourable income tax adjustments resulting from reductions in the Province of Ontario's corporate income tax rates.
- ***Third quarter 2009*** Energy's EBIT included net unrealized gains of $14 million pre-tax ($10 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

- ***Second quarter 2009*** Energy's EBIT included net unrealized losses of $7 million pre-tax ($5 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Energy's EBIT also included contributions from Portlands Energy, which was placed in service in April 2009, and the negative impact of Western Power's lower overall realized power prices.
- ***First quarter 2009*** Energy's EBIT included net unrealized losses of $13 million pre-tax ($9 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.
- ***Fourth quarter 2008*** Energy's EBIT included net unrealized gains of $7 million pre-tax ($6 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Corporate's EBIT included net unrealized losses of $57 million pre-tax ($39 million after tax) for changes in the fair value of derivatives that were used to manage the Company's exposure to rising interest rates but did not qualify as hedges for accounting purposes.
- ***Third quarter 2008*** Energy's EBIT included contributions from the August 2008 acquisition of Ravenswood. Net Income included favourable income tax adjustments of $26 million from an internal restructuring and realization of losses.
- ***Second quarter 2008*** Energy's EBIT included net unrealized gains of $12 million pre-tax ($8 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. In addition, Western Power's revenues and EBIT increased due to higher overall realized prices and market heat rates in Alberta.
- ***First quarter 2008*** Pipelines' EBIT included $279 million pre-tax ($152 million after tax) received by GTN and Portland from the Calpine bankruptcy settlements, and proceeds of $17 million pre-tax ($10 million after tax) from a lawsuit settlement. Energy's EBIT included a writedown of $41 million pre-tax ($27 million after tax) of costs related to the Broadwater LNG project and net unrealized losses of $17 million pre-tax ($12 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

FOURTH QUARTER 2009 HIGHLIGHTS

Reconciliation of Comparable Earnings, Comparable EBITDA, Comparable EBIT and EBIT to Net Income Applicable to Common Shares

Three months ended December 31 *(unaudited)(millions of dollars except per share amounts)*	Pipelines		Energy		Corporate		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Comparable EBITDA[1]	**745**	780	**248**	297	**(28)**	(33)	**965**	1,044
Depreciation and amortization	**(257)**	(224)	**(86)**	(80)	**–**	–	**(343)**	(304)
Comparable EBIT[1]	**488**	556	**162**	217	**(28)**	(33)	**622**	740
Specific items:								
Dilution gain from reduced interest in PipeLines LP	**29**	–	**–**	–	**–**	–	**29**	–
Fair value adjustment of natural gas inventory in storage and forward contracts	**–**	–	**7**	7	**–**	–	**7**	7
EBIT[1]	**517**	556	**169**	224	**(28)**	(33)	**658**	747
Interest expense							**(184)**	(326)
Interest expense of joint ventures							**(17)**	(21)
Interest income and other							**22**	(4)
Income taxes							**(67)**	(95)
Non-controlling interests							**(25)**	(24)
Net Income							**387**	277
Preferred share dividends							**(6)**	–
Net Income Applicable to Common Shares							**381**	277
Specific items (net of tax, where applicable):								
Dilution gain from reduced interest in PipeLines LP							**(18)**	–
Fair value adjustment of natural gas inventory in storage and forward contracts							**(5)**	(6)
Income tax adjustments							**(30)**	–
Comparable Earnings[1]							**328**	271
Net Income per Share – Basic[2]							**$0.56**	$0.47
Net Income per Share – Diluted							**$0.56**	$0.46

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of comparable EBITDA, comparable EBIT, EBIT, comparable earnings and comparable earnings per share.

(2) For the three months ended December 31

(unaudited)	**2009**	2008
Comparable Earnings per Share[1]	**$0.48**	$0.46
Specific items (net of tax, where applicable):		
Dilution gain from reduced interest in PipeLines LP	**0.03**	–
Fair value adjustment of natural gas inventory in storage and forward contracts	**0.01**	0.01
Income tax adjustments	**0.04**	–
Net Income per Share	**$0.56**	$0.47

TransCanada's net income was $387 million and net income applicable to common shares was $381 million or $0.56 per share in fourth quarter 2009 compared to $277 million or $0.47 per share in fourth quarter 2008. The $104 million increase in net income applicable to common shares reflected:

- Decreased EBIT from Pipelines primarily due to the negative impact of a weaker U.S. dollar on Pipeline's U.S. operations and increased business development costs related to the Alaska pipeline project. These decreases were partially offset by an $18 million after tax ($29 million pre-tax) dilution gain resulting from TransCanada's reduced ownership interest in PipeLines LP following PipeLines LP's public issuance of common units.
- decreased EBIT from Energy primarily due to lower power prices in Western Power and U.S. Power, and the impact of a weaker U.S. dollar on Energy's U.S. operations, partially offset by higher contribution from the Natural Gas Storage business due to increased third party storage revenues and increased earnings as a result of the start up of Portlands Energy.
- decreased interest expense primarily due to increased capitalized interest, reduced losses from changes in the fair value of interest rate derivatives used to manage TransCanada's exposure to fluctuating interest rates and the positive impact of a weaker U.S. dollar. These decreases were partially offset by incremental interest expense for new debt issuances in 2009.
- increased interest income and other due to the positive impact of a weaker U.S. dollar on working capital balances and changes in the fair value of derivatives used to manage the Company's exposure to foreign exchange rate fluctuations; and
- decreased income tax expense primarily due to positive income tax adjustments in fourth quarter 2009, including $30 million resulting from a reduction in the Province of Ontario's corporate income tax rates, partially offset by higher pre-tax income.

The increase in earnings per share in fourth quarter 2009 from fourth quarter 2008 was partially offset by a 14 per cent increase in the average number of common shares outstanding, following the Company's issuance of 58.4 million and 35.1 million common shares in second quarter 2009 and fourth quarter 2008, respectively.

Comparable earnings in fourth quarter 2009 increased $57 million or $0.02 per share to $328 million or $0.48 per share, compared to $271 million or $0.46 per share for the same period in 2008. Comparable earnings in fourth quarter 2009 excluded the $18 million after tax dilution gain resulting from TransCanada's reduced ownership in PipeLines LP and the $30 million of favourable income tax adjustments. Comparable earnings in fourth quarter 2009 and 2008 also excluded net unrealized after tax gains of $5 million ($7 million pre-tax) and $6 million ($7 million pre-tax), respectively, resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

Pipelines comparable EBIT was $488 million in fourth quarter 2009 compared to $556 million for the same period in 2008. Comparable EBIT excluded the $29 million pre-tax dilution gain resulting from a reduction in TransCanada's ownership interest in PipeLines LP following PipeLines LP's public issuance of common units in fourth quarter 2009.

Canadian Mainline's net income for fourth quarter 2009 decreased $2 million to $72 million from $74 million for the same period in 2008. Net income for fourth quarter 2009 reflected a lower average investment base and a lower ROE set by the NEB at 8.57 per cent in 2009 compared to 8.71 per cent in 2008, partially offset by higher OM&A cost savings.

Canadian Mainline's EBITDA for fourth quarter 2009 of $282 million decreased $18 million compared to the same period in 2008 primarily due to lower revenues as a result of a recovery of lower income taxes and a lower overall return on average investment base in the 2009 tolls, partially offset by higher OM&A cost savings.

The Alberta System's net income was $45 million in fourth quarter 2009 compared to $48 million for the same period in 2008. Earnings in 2009 and 2008 reflected the impact of the 2008-2009 Revenue Requirement Settlement approved by the AUC in December 2008 and by the NEB in December 2009.

The Alberta System's EBITDA was $193 million in fourth quarter 2009 compared to $152 million for the same period in 2008. The increase reflected higher revenues as a result of the recovery of higher depreciation and income taxes, partially offset by lower settlement earnings.

EBITDA from Other Canadian Pipelines was $15 million in fourth quarter 2009 compared to $11 million for the same period in 2008. The increase was primarily due to an adjustment to TQM's cost of capital for 2009.

ANR's EBITDA in fourth quarter 2009 was $84 million compared to $99 million for the same period in 2008. The decrease in EBITDA was primarily due to the negative impact of a weaker U.S. dollar.

GTN's EBITDA in fourth quarter 2009 decreased $9 million from the same period in 2008 primarily due to the negative impact of a weaker U.S. dollar and the sale of North Baja to PipeLines LP.

EBITDA for the remainder of the U.S. Pipelines was $132 million in fourth quarter 2009 compared to $144 million for the same period in 2008. The decrease was primarily due to the negative impact of a weaker U.S. dollar on U.S. Pipelines operations, partially offset by the acquisition of North Baja by PipeLines LP.

Pipelines business development comparable EBITDA losses increased $27 million in fourth quarter 2009 compared to the same period in 2008 primarily due to increased business development costs related to the Alaska pipeline project.

Energy's comparable EBIT was $162 million in fourth quarter 2009 compared to $217 million in fourth quarter 2008. Comparable EBIT in fourth quarter 2009 and fourth quarter 2008 excluded net unrealized gains of $7 million in each period resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

Western Power's EBITDA of $61 million and power revenues of $203 million in fourth quarter 2009 decreased $67 million and $95 million, respectively, compared to the same period in 2008. These decreases were primarily due to lower earnings from the Alberta power portfolio resulting from lower overall realized power prices on lower volumes of power sold. The reduction in power prices and sales volumes reflected reduced demand for electricity in Alberta as a result of the North American economic slowdown. Average spot market power prices in Alberta decreased 51 per cent or $49 per MWh in fourth quarter 2009 compared to fourth quarter 2008.

Eastern Power's EBITDA of $56 million in fourth quarter 2009 increased $13 million compared to the same period in 2008. These increases were primarily due to incremental earnings from Portlands Energy which went into service in April 2009.

TransCanada's proportionate share of Bruce Power's comparable EBITDA of $70 million in fourth quarter 2009 was consistent with fourth quarter 2008. Increased revenues from higher realized prices and an annual lease expense reduction at Bruce B were offset by higher non-lease operating expenses and lower volumes caused by an increase in outage days.

TransCanada's proportionate share of Bruce A's comparable EBITDA decreased $28 million to a loss of $29 million in fourth quarter 2009 compared to a loss of $1 million in fourth quarter 2008. The higher loss was due to decreased volumes and higher operating costs as a result of an unplanned extension of the two planned outages which were rescheduled to September 2009 from March 2009. Bruce A's plant availability in fourth quarter 2009 was 47 per cent as a result of 84 outage days compared to an availability of 62 per cent and 63 outage days in the same period in 2008.

TransCanada's proportionate share of Bruce B's comparable EBITDA increased $28 million to $99 million in fourth quarter 2009 compared to fourth quarter 2008 primarily due to higher realized prices resulting from the recognition of payments received pursuant to the floor price mechanism in Bruce B's contract with the OPA, as well as a reduction in annual lease expense. Provisions in the Bruce B lease agreement with Ontario Power Generation allow for a reduction in annual lease expense if the annual Ontario spot price for electricity was less than $30 per MWh.

U.S. Power's comparable EBITDA for fourth quarter 2009 of $29 million decreased $21 million compared to the same period in 2008. The decrease was primarily due to lower overall realized power prices and the impact of a weaker U.S. dollar, partially offset by incremental revenue realized on contract sales in New England. While average spot market power prices in New England decreased in fourth quarter 2009 compared to fourth quarter 2008, the majority of U.S. Power's sales volumes were sold at contracted prices.

Natural Gas Storage's comparable EBITDA in fourth quarter 2009 was $49 million compared to $34 million for the same period in 2008. The $15 million increase was primarily due to increased third party storage revenues as a result of higher realized seasonal natural gas price spreads. Comparable EBITDA excluded net unrealized gains of $7 million in fourth quarter 2009 (2008 – gains of $7 million), resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

Corporate EBIT losses in fourth quarter 2009 were $28 million compared to losses of $33 million for the same period in 2008. The decreases in EBIT losses were primarily due to lower support service costs in fourth quarter 2009.

Interest expense in fourth quarter 2009 decreased $142 million to $184 million from $326 million in fourth quarter 2008. The decrease reflected increased capitalized interest to finance the Company's larger capital growth program in 2009, primarily due to Keystone construction, and a decrease in U.S. dollar-denominated interest expense due to the impact of a weaker U.S. dollar in fourth quarter 2009 compared to fourth quarter 2008. Interest expense also decreased due to reduced losses in fourth quarter 2009 compared to 2008 from changes in the fair value of derivatives used to manage the Company's exposure to interest rate fluctuations. These decreases were partially offset by incremental interest expense on new debt issues of US$2.0 billion in January 2009 and $700 million in February 2009.

Interest Income and Other in fourth quarter 2009 was income of $22 million compared to an expense of $4 million for the same period in 2008. The increase in income of $26 million in fourth quarter 2009 was primarily due to the positive impact of a weaker U.S. dollar on working capital balances in fourth quarter 2009 and higher gains from changes in the fair value of derivatives used to manage the Company's exposure to foreign exchange rate fluctuations. These increases were partially offset by lower interest income due to lower interest rates.

Income Taxes were $67 million in fourth quarter 2009 compared to $95 million for the same period in 2008. The decrease was primarily due to positive income tax adjustments in 2009, including a $30 million favourable adjustment resulting from a reduction in the Province of Ontario's corporate income tax rates, partially offset by higher pre-tax income.

SHARE INFORMATION

At February 22, 2010, TransCanada had 687 million issued and outstanding common shares, and 22 million issued and outstanding first preferred shares, Series 1. In addition, there were eight million outstanding options to purchase common shares, of which six million were exercisable as at February 22, 2010.

OTHER INFORMATION

Additional information relating to TransCanada, including the Company's Annual Information Form and other continuous disclosure documents, is available on SEDAR at www.sedar.com under TransCanada Corporation.

Other selected consolidated financial information for 2000 to 2009 is found under the heading "Ten Year Financial Highlights" in the Supplementary Information section of the Company's Annual Report.

GLOSSARY OF TERMS

AGIA	Alaska Gasline Inducement Act
Alaska Pipeline Project	A proposed natural gas pipeline extending from Prudhoe Bay, Alaska to either Alberta or Valdez, Alaska
Alberta System	A natural gas transmission system in Alberta
American Natural Resources (ANR)	A natural gas transmission system extending from producing fields located primarily in Texas, Oklahoma, the Gulf of Mexico and Louisiana to markets located primarily in Wisconsin, Michigan, Illinois, Ohio and Indiana, and regulated underground natural gas storage facilities in Michigan
ANR Pipeline	ANR Pipeline Company
APG	Aboriginal Pipeline Group
ATWACC	After-tax weighted average cost of capital
AUC	Alberta Utilities Commission
B.C.	British Columbia
Bbl/d	Barrel(s) per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
Bear Creek	A natural gas-fired cogeneration plant near Grande Prairie, Alberta
Bécancour	A natural gas-fired cogeneration plant near Trois-Rivières, Québec
Bison	A pipeline under construction extending from the Powder River Basin in Wyoming to Northern Border in North Dakota
BPC	BPC Generation Infrastructure Trust
Broadwater	A proposed offshore LNG project in Long Island Sound, New York
Bruce A	A partnership interest in the nuclear power generation facilities of Bruce Power A L.P.
Bruce B	A partnership interest in the nuclear power generation facilities of Bruce Power L.P.
Bruce Power	Bruce A and Bruce B, collectively
Calpine	Calpine Corporation
Canadian Mainline	A natural gas transmission system extending from the Alberta/Saskatchewan border east into Québec
Cancarb	A waste-heat fuelled power plant at the Cancarb thermal carbon black facility in Medicine Hat, Alberta
Carseland	A natural gas-fired cogeneration plant located near Carseland, Alberta
Cartier Wind	Five wind farms in Gaspé, Québec, three of which are operational and two are under construction
Chinook	A proposed power transmission line project that will originate in Montana and terminate in Nevada
CICA	Canadian Institute of Chartered Accountants
CNSC	Canadian Nuclear Safety Commission
CO_2	Carbon dioxide
Coolidge	A simple-cycle, natural gas-fired peaking power generation station under construction in Coolidge, Arizona
CrossAlta	An underground natural gas storage facility near Crossfield, Alberta
DB Plans	Defined benefit plans
DRP	Dividend Reinvestment and Share Purchase Plan
EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes, depreciation and amortization
Edson	A natural gas storage facility near Edson, Alberta
EIC	Emerging Issues Committee
FASB	Financial Accounting Standards Board
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission (U.S.)
Foothills	A natural gas transmission system extending from central Alberta to the B.C./U.S. border and to the Saskatchewan/U.S. border
GAAP	Generally accepted accounting principles
Gas Pacifico	A natural gas transmission system extending from Loma de la Lata, Argentina to Concepción, Chile
GHG	Greenhouse gas
Grandview	A natural gas-fired cogeneration plant near Saint John, New Brunswick
Great Lakes	A natural gas transmission system that connects to the Canadian Mainline and serves markets in Eastern Canada and the northeastern and midwestern U.S.
Gas Transmission Northwest (GTN)	A natural gas transmission system extending from the B.C./Idaho border to the Oregon/California border, traversing Idaho, Washington and Oregon
GTNC	Gas Transmission Northwest Company
Guadalajara	A natural gas pipeline under construction in Mexico extending from Manzanillo, Colima to Guadalajara, Jalisco
GWh	Gigawatt hours
Halton Hills	A natural gas-fired, combined-cycle power plant under construction near Toronto, Ontario
HS&E	Health, Safety and Environment
IASB	International Accounting Standards Board
IESO	Independent Electricity System Operator
IFRS	International Financial Reporting Standards
INNERGY	An industrial natural gas marketing company based in Concepción, Chile

Iroquois	A natural gas transmission system that connects with the Canadian Mainline near Waddington, New York, and delivers natural gas to the northeastern U.S.
Irving	Irving Oil Limited
ISO	International Organization for Standardization
Keystone	A pipeline under construction that will transport crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, and to Cushing, Oklahoma
Kibby Wind	A wind power project located in Kibby and Skinner Townships in northwestern Franklin County, Maine
km	Kilometre(s)
LIBOR	London Interbank Offered Rate
LNG	Liquefied natural gas
MacKay River	A natural gas-fired cogeneration plant located near Fort McMurray, Alberta
MD&A	Management's Discussion and Analysis
Mackenzie Gas Pipeline (MGP) Project	A proposed natural gas pipeline extending from a point near Inuvik, Northwest Territories to the northern border of Alberta
mmcf/d	Million cubic feet per day
Moody's	Moody's Investors Service
MOP	Maximum operating pressure
MW	Megawatt(s)
MWh	Megawatt hours
NEB	National Energy Board of Canada
NGTL	NOVA Gas Transmission Ltd.
North Baja	A natural gas transmission system extending from Arizona to the Baja California, Mexico/California border
Northern Border	A natural gas transmission system extending from a point near Monchy, Saskatchewan to the U.S. Midwest
NYISO	New York Independent System Operator
Oakville	A proposed natural gas-fired, combined-cycle power plant in Oakville, Ontario
OM&A	Operating, maintenance and administration
OMERS	Ontario Municipal Employees Retirement System
OPA	Ontario Power Authority
Ocean State Power (OSP)	A natural gas-fired, combined-cycle plant in Burrillville, Rhode Island
Palomar	A proposed pipeline extending from GTN to the Columbia River northwest of Portland
PipeLines LP	TC PipeLines, LP
Portland	A natural gas transmission system extending from a point near East Hereford, Québec to the northeastern U.S.
Portlands Energy	A natural gas-fired, combined-cycle power plant in Toronto, Ontario
PPA	Power purchase arrangement
PWU	Power Workers' Union Trust
Ravenswood	A natural gas- and oil-fired generating facility consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology located in Queens, New York
Redwater	A natural gas-fired cogeneration plant located near Redwater, Alberta
RGGI	Regional Greenhouse Gas Initiative
ROE	Rate of return on common equity
S&P	Standard and Poor's
SEC	Securities and Exchange Commission (U.S.)
SEP	Society of Energy Professionals Trust
Sheerness	A coal-fired power generating facility located near Hanna, Alberta
Sundance A	A coal-fired power generating facility located near Wabamun, Alberta
Sundance B	A coal-fired power generating facility located near Wabamun, Alberta
Tamazunchale	A natural gas transmission system in Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi
TC Hydro	Hydroelectric generation assets located in New Hampshire, Vermont and Massachusetts
TCPL	TransCanada PipeLines Limited
TCPL USA	TransCanada PipeLine USA Ltd.
TCPM	TransCanada Power Marketing Ltd.
Trans Québec & Maritimes (TQM)	A natural gas transmission system that connects with the Canadian Mainline and transports natural gas in Québec, from Montreal to the Portland system and to Québec City
TQM Pipeline	Trans Québec & Maritimes Pipeline Inc.
TransCanada or the Company	TransCanada Corporation
TransGas	A natural gas transmission system extending from Mariquita in the central region of Colombia to Cali in the southwest region of Colombia
Tuscarora	A natural gas transmission system extending from Malin, Oregon to Wadsworth, Nevada
U.S.	United States
VaR	Value-at-Risk
Ventures LP	Natural gas transmission systems in Alberta that supply natural gas to the oilsands region of northern Alberta and to a petrochemical complex at Joffre, Alberta
WCI	Western Climate Initiative
WCSB	Western Canada Sedimentary Basin
Zephyr	A proposed power transmission line project originating in Wyoming and terminating in Nevada

Report of Management

The consolidated financial statements included in this Annual Report are the responsibility of the management of TransCanada Corporation (TransCanada or the Company) and have been approved by the Board of Directors of the Company. These consolidated financial statements have been prepared by management in accordance with generally accepted accounting principles (GAAP) in Canada and include amounts that are based on estimates and judgements. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management's Discussion and Analysis in this Annual Report has been prepared by management based on the Company's financial results prepared in accordance with GAAP. It compares the Company's financial and operating performance in 2009 to that in 2008 and should be read in conjunction with the consolidated financial statements and accompanying notes. In addition, it highlights significant changes between 2008 and 2007.

Management has designed and maintains a system of internal controls over financial reporting, including a program of internal audits. Management believes these controls provide reasonable assurance that financial records are reliable and form a proper basis for the preparation of financial statements. The internal controls over financial reporting include management's communication to employees of policies that govern ethical business conduct.

Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal controls over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded, based on its evaluation, that internal controls over financial reporting are effective as of December 31, 2009 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

The Board of Directors has appointed an Audit Committee consisting of independent, non-management directors. The Audit Committee meets with management at least five times a year and meets independently with the internal and external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form. The Audit Committee's responsibilities include overseeing management's performance in carrying out its financial reporting responsibilities and reviewing the Annual Report, including the consolidated financial statements, before the consolidated financial statements are submitted to the Board of Directors for approval. The internal and independent external auditors are able to access the Audit Committee without the requirement to obtain prior management approval.

The Audit Committee approves the terms of engagement of the independent external auditors and reviews the annual audit plan, the Auditors' Report and the results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The shareholders have appointed KPMG LLP as independent external auditors to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's consolidated financial position, results of operations and cash flows in accordance with GAAP. The report of KPMG LLP outlines the scope of its examination and its opinion on the consolidated financial statements.

Harold N. Kvisle
President and
Chief Executive Officer

Gregory A. Lohnes
Executive Vice-President and
Chief Financial Officer

February 22, 2010

Auditors' Report

To the Shareholders of TransCanada Corporation

We have audited the consolidated balance sheets of TransCanada Corporation as at December 31, 2009 and 2008 and the consolidated statements of income, comprehensive income, accumulated other comprehensive income, shareholders' equity and cash flows for each of the years in the three year period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

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

KPMG LLP

Chartered Accountants
Calgary, Canada

February 22, 2010

TRANSCANADA CORPORATION

CONSOLIDATED INCOME

Year ended December 31 *(millions of dollars except per share amounts)*	**2009**	2008	2007
Revenues	**8,966**	8,619	8,828
Operating and Other Expenses/(Income)			
Plant operating costs and other	**3,367**	3,014	3,030
Commodity purchases resold	**1,511**	1,501	1,901
Other income	**(49)**	(38)	(48)
Calpine bankruptcy settlements (Note 18)	**–**	(279)	–
Writedown of Broadwater LNG project costs (Note 7)	**–**	41	–
	4,829	4,239	4,883
	4,137	4,380	3,945
Depreciation and amortization (Note 7)	**1,377**	1,247	1,237
	2,760	3,133	2,708
Financial Charges/(Income)			
Interest expense (Note 10)	**954**	943	943
Interest expense of joint ventures (Note 11)	**64**	72	75
Interest income and other	**(121)**	(54)	(120)
	897	961	898
Income before Income Taxes and Non-Controlling Interests	**1,863**	2,172	1,810
Income Taxes (Note 19)			
Current	**30**	526	432
Future	**357**	76	58
	387	602	490
Non-Controlling Interests (Note 15)	**96**	130	97
Net Income	**1,380**	1,440	1,223
Preferred Share Dividends (Note 17)	**6**	–	–
Net Income Applicable to Common Shares	**1,374**	1,440	1,223
Net Income per Share (Note 16)			
Basic	**$2.11**	$2.53	$2.31
Diluted	**$2.11**	$2.52	$2.30

The accompanying notes to the consolidated financial statements are an integral part of these statements.

TRANSCANADA CORPORATION
CONSOLIDATED CASH FLOWS

Year ended December 31 *(millions of dollars)*	**2009**	2008	2007
Cash Generated from Operations			
Net income	**1,380**	1,440	1,223
Depreciation and amortization	**1,377**	1,247	1,237
Future income taxes (Note 19)	**357**	76	58
Non-controlling interests (Note 15)	**96**	130	97
Employee future benefits funding (in excess of)/lower than expense (Note 22)	**(111)**	17	43
Writedown of Broadwater LNG project costs (Note 7)	**–**	41	–
Other	**(19)**	70	(37)
	3,080	3,021	2,621
(Increase)/decrease in operating working capital (Note 23)	**(90)**	135	63
Net cash provided by operations	**2,990**	3,156	2,684
Investing Activities			
Capital expenditures	**(5,417)**	(3,134)	(1,651)
Acquisitions, net of cash acquired (Note 9)	**(902)**	(3,229)	(4,223)
Disposition of assets, net of current income taxes (Note 9)	**–**	28	35
Deferred amounts and other	**(594)**	(484)	(188)
Net cash used in investing activities	**6,913**	(6,819)	(6,027)
Financing Activities			
Dividends on common and preferred shares (Notes 16 and 17)	**(728)**	(577)	(546)
Distributions paid to non-controlling interests	**(100)**	(141)	(88)
Notes payable (repaid)/issued, net (Note 20)	**(244)**	1,293	(46)
Long-term debt issued, net of issue costs (Note 10)	**3,267**	2,197	2,616
Reduction of long-term debt	**(1,005)**	(840)	(1,088)
Long-term debt of joint ventures issued (Note 11)	**226**	173	142
Reduction of long-term debt of joint ventures	**(246)**	(120)	(157)
Common shares issued, net of issue costs (Note 16)	**1,820**	2,384	1,711
Preferred shares issued, net of issue costs (Note 17)	**539**	–	–
Partnership units of subsidiary issued, net of issue costs (Note 9)	**193**	–	348
Junior subordinated notes issued, net of issue costs (Note 12)	**–**	–	1,094
Preferred securities redeemed	**–**	–	(488)
Net cash provided by financing activities	**3,722**	4,369	3,498
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(110)**	98	(50)
(Decrease)/Increase in Cash and Cash Equivalents	**(311)**	804	105
Cash and Cash Equivalents			
Beginning of year	**1,308**	504	399
Cash and Cash Equivalents			
End of year	**997**	1,308	504

The accompanying notes to the consolidated financial statements are an integral part of these statements.

TRANSCANADA CORPORATION
CONSOLIDATED BALANCE SHEET

December 31 *(millions of dollars)*	**2009**	2008
ASSETS		
Current Assets		
Cash and cash equivalents	**997**	1,308
Accounts receivable	**966**	1,280
Inventories	**511**	489
Other	**701**	523
	3,175	3,600
Plant, Property and Equipment (Note 5)	**32,879**	29,189
Goodwill (Note 6)	**3,763**	4,397
Regulatory Assets (Note 14)	**1,524**	201
Intangibles and Other Assets (Note 7)	**2,500**	2,027
	43,841	39,414
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable (Note 20)	**1,687**	1,702
Accounts payable	**2,195**	2,110
Accrued interest	**377**	359
Current portion of long-term debt (Note 10)	**478**	786
Current portion of long-term debt of joint ventures (Note 11)	**212**	207
	4,949	5,164
Regulatory Liabilities (Note 14)	**385**	317
Deferred Amounts (Note 13)	**743**	1,168
Future Income Taxes (Note 19)	**2,856**	1,223
Long-Term Debt (Note 10)	**16,186**	15,368
Long-Term Debt of Joint Ventures (Note 11)	**753**	869
Junior Subordinated Notes (Note 12)	**1,036**	1,213
	26,908	25,322
Non-Controlling Interests (Note 15)	**1,174**	1,194
Shareholders' Equity	**15,759**	12,898
	43,841	39,414

Commitments, Contingencies and Guarantees (Note 24)

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Harold N. Kvisle
Director

Kevin E. Benson
Director

TRANSCANADA CORPORATION
CONSOLIDATED COMPREHENSIVE INCOME

Year ended December 31 *(millions of dollars)*	**2009**	2008	2007
Net Income	**1,380**	1,440	1,223
Other Comprehensive (Loss)/Income, Net of Income Taxes			
Change in foreign currency translation gains and losses on investments in foreign operations(1)	**(471)**	571	(350)
Change in gains and losses on hedges of investments in foreign operations(2)	**258**	(589)	79
Change in gains and losses on derivative instruments designated as cash flow hedges(3)	**77**	(60)	42
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods(4)	**(24)**	(23)	42
Change in gains and losses on available-for-sale financial instruments(5)	**–**	2	–
Other Comprehensive (Loss)/Income	**(160)**	(99)	(187)
Comprehensive Income	**1,220**	1,341	1,036

(1) Net of income tax expense of $92 million in 2009 (2008 – $104 million recovery; 2007 – $101 million expense).

(2) Net of income tax expense of $124 million in 2009 (2008 – $303 million recovery; 2007 – $41 million expense).

(3) Net of income tax expense of $7 million in 2009 (2008 – $41 million recovery; 2007 – $27 million expense).

(4) Net of income tax expense of $9 million in 2009 (2008 – $19 million recovery; 2007 – $23 million expense).

(5) Net of income tax expense of nil in 2008.

The accompanying notes to the consolidated financial statements are an integral part of these statements.

TRANSCANADA CORPORATION

CONSOLIDATED ACCUMULATED OTHER COMPREHENSIVE INCOME

(millions of dollars)	Currency Translation Adjustments	Cash Flow Hedges and Other	Total
Balance at January 1, 2007	(90)	–	(90)
Transition adjustment resulting from adopting new financial instruments standards(1)	–	(96)	(96)
Change in foreign currency translation gains and losses on investments in foreign operations(2)	(350)	–	(350)
Change in gains and losses on hedges of investments in foreign operations(3)	79	–	79
Change in gains and losses on derivative instruments designated as cash flow hedges(4)	–	42	42
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods(5)	–	42	42
Balance at December 31, 2007	(361)	(12)	(373)
Change in foreign currency translation gains and losses on investments in foreign operations(2)	571	–	571
Change in gains and losses on hedges of investments in foreign operations(3)	(589)	–	(589)
Change in gains and losses on derivative instruments designated as cash flow hedges(4)	–	(60)	(60)
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods(5)	–	(23)	(23)
Change in gains and losses on available-for-sale financial instruments(6)	–	2	2
Balance at December 31, 2008	(379)	(93)	(472)
Change in foreign currency translation gains and losses on investments in foreign operations(2)	**(471)**	–	**(471)**
Change in gains and losses on hedges of investments in foreign operations(3)	**258**	–	**258**
Change in gains and losses on derivative instruments designated as cash flow hedges(4)	–	**77**	**77**
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods(5)(7)	–	**(24)**	**(24)**
Balance at December 31, 2009	**(592)**	**(40)**	**(632)**

(1) Net of income tax recovery of $44 million in 2007.

(2) Net of income tax expense of $92 million in 2009 (2008 – $104 million recovery; 2007 – $101 million expense).

(3) Net of income tax expense of $124 million in 2009 (2008 – $303 million recovery; 2007 – $41 million expense).

(4) Net of income tax expense of $7 million in 2009 (2008 – $41 million recovery; 2007 – $27 million expense).

(5) Net of income tax expense of $9 million in 2009 (2008 – $19 million recovery; 2007 – $23 million expense).

(6) Net of income tax expense of nil in 2008.

(7) Gains related to cash flow hedges reported in Accumulated Other Comprehensive Income and expected to be reclassified to Net Income in 2010 are estimated to be $14 million ($12 million, net of tax). These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

The accompanying notes to the consolidated financial statements are an integral part of these statements.

TRANSCANADA CORPORATION
CONSOLIDATED SHAREHOLDERS' EQUITY

Year ended December 31 *(millions of dollars)*	**2009**	2008	2007
Common Shares			
Balance at beginning of year	**9,264**	6,662	4,794
Proceeds from shares issued under public offering, net of issue costs (Note 16)	**1,792**	2,363	1,683
Shares issued under dividend reinvestment plan (Note 16)	**254**	218	157
Proceeds from shares issued on exercise of stock options (Note 16)	**28**	21	28
Balance at end of year	**11,338**	9,264	6,662
Preferred Shares			
Balance at beginning of year	**–**	–	–
Proceeds from shares issued under public offering, net of issue costs (Note 17)	**539**	–	–
Balance at end of year	**539**	–	–
Contributed Surplus			
Balance at beginning of year	**279**	276	273
Increased ownership in PipeLines LP (Note 9)	**47**	–	–
Issuance of stock options (Note 16)	**2**	3	3
Balance at end of year	**328**	279	276
Retained Earnings			
Balance at beginning of year	**3,827**	3,220	2,724
Net income	**1,380**	1,440	1,223
Common share dividends	**(1,015)**	(833)	(731)
Preferred share dividends (Note 17)	**(6)**	–	–
Transition adjustment resulting from adopting new financial instruments accounting standards	**–**	–	4
Balance at end of year	**4,186**	3,827	3,220
Accumulated Other Comprehensive Income			
Balance at beginning of year	**(472)**	(373)	(90)
Other comprehensive (loss)/income	**(160)**	(99)	(187)
Transition adjustment resulting from adopting new financial instruments accounting standards	**–**	–	(96)
Balance at end of year	**(632)**	(472)	(373)
	3,554	3,355	2,847
Total Shareholders' Equity	**15,759**	12,898	9,785

The accompanying notes to the consolidated financial statements are an integral part of these statements.

TRANSCANADA CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 DESCRIPTION OF TRANSCANADA'S BUSINESS

TransCanada Corporation (TransCanada or the Company) is a leading North American energy company. TransCanada operates in two business segments, Pipelines and Energy, each of which offers different products and services.

Pipelines
The Pipelines segment consists primarily of the Company's investments in regulated pipelines and regulated natural gas storage facilities. Through its Pipelines segment, TransCanada owns and operates:

- a natural gas transmission system extending from the Alberta/Saskatchewan border east into Québec (Canadian Mainline);
- a natural gas transmission system in Alberta (Alberta System);
- a natural gas transmission system extending from producing fields located primarily in Texas, Oklahoma, the Gulf of Mexico and Louisiana to markets located primarily in Wisconsin, Michigan, Illinois, Ohio and Indiana, and to regulated natural gas storage facilities in Michigan (ANR);
- a natural gas transmission system extending from the British Columbia (B.C.)/Idaho border to the Oregon/California border (GTN);
- a natural gas transmission system extending from central Alberta to the B.C./Idaho border and to the Saskatchewan/Montana border (Foothills);
- natural gas transmission systems in Alberta that supply natural gas to the oil sands region of northern Alberta and to a petrochemical complex at Joffre, Alberta (Ventures LP); and
- a natural gas transmission system in Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi (Tamazunchale).

Through its Pipelines segment, TransCanada operates and has ownership interests in pipeline systems as follows:

- a 53.6 per cent direct ownership interest in a natural gas transmission system that connects to the Canadian Mainline and serves markets in Eastern Canada and the northeastern and midwestern United States (U.S.) (Great Lakes);
- a 61.7 per cent interest in a natural gas transmission system that extends from a point near East Hereford, Québec to the northeastern U.S. (Portland);
- a 50 per cent interest in a natural gas transmission system that connects with the Canadian Mainline and transports natural gas in Québec, from Montreal to the Portland system and to Québec City (TQM); and
- a 38.2 per cent interest in TC PipeLines, LP (PipeLines LP), whose ownership interests in pipelines operated by TransCanada are as follows:
  - a 46.4 per cent interest in Great Lakes, in which TransCanada has a combined 71.3 per cent effective ownership interest through PipeLines LP and a direct interest described above;
  - a 50 per cent interest in a natural gas transmission system extending from a point near Monchy, Saskatchewan, to the U.S. Midwest (Northern Border), in which TransCanada has a 19.1 per cent effective ownership interest through PipeLines LP;
  - a 100 per cent interest in a natural gas transmission system extending from Arizona to Baja California, at the Mexico/California border (North Baja), in which TransCanada has a 38.2 per cent effective ownership interest through PipeLines LP; and
  - a 100 per cent interest in a natural gas transmission system extending from Malin, Oregon to Wadsworth, Nevada (Tuscarora), in which TransCanada has a 38.2 per cent effective ownership interest through PipeLines LP.

TransCanada does not operate but has ownership interests in pipelines and natural gas marketing activities as follows:

- a 44.5 per cent interest in a natural gas transmission system that connects with the Canadian Mainline near Waddington, New York, and delivers natural gas to customers in the northeastern U.S. (Iroquois);
- a 46.5 per cent interest in a natural gas transmission system extending from Mariquita to Cali in Colombia (TransGas); and
- a 30 per cent interest in a natural gas transmission system extending from Loma de la Lata, Argentina to Concepción, Chile (Gas Pacifico), and in an industrial natural gas marketing company based in Concepción (INNERGY).

TransCanada is constructing pipelines or developing pipeline projects, which it expects to operate, including the following:

- a pipeline under construction that will transport crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, and at Cushing, Oklahoma, and a development project to expand the pipeline and extend it to the Gulf Coast (Keystone);
- a pipeline under construction that will transport natural gas from Wyoming to Northern Border in North Dakota (Bison); and
- a pipeline under construction in Mexico that will transport natural gas from Manzanillo to Guadalajara (Guadalajara).

Energy

The Energy segment consists primarily of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities. Through its Energy segment, the Company owns and operates:

- natural gas-fired cogeneration plants in Alberta at Carseland, Redwater, Bear Creek and MacKay River;
- a waste-heat fuelled power plant at the Cancarb thermal carbon black facility in Medicine Hat, Alberta (Cancarb);
- a natural gas and oil-fired generating facility in Queens, New York, consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology (Ravenswood);
- hydroelectric generation assets located in New Hampshire, Vermont and Massachusetts (TC Hydro);
- a natural gas-fired, combined-cycle plant in Burrillville, Rhode Island (Ocean State Power);
- a natural gas-fired cogeneration plant near Trois-Rivières, Québec (Bécancour);
- a natural gas-fired cogeneration plant near Saint John, New Brunswick (Grandview);
- a natural gas storage facility near Edson, Alberta (Edson); and
- the first phase of a two-phase wind power project located in Kibby and Skinner Townships in northwestern Franklin County, Maine (Kibby Wind).

TransCanada does not operate but through its Energy segment has ownership interests in power generation plants and non-regulated natural gas storage facilities as follows:

- a 48.8 per cent partnership interest and a 31.6 per cent partnership interest in the nuclear power generation facilities of Bruce A and Bruce B (collectively Bruce Power), respectively, located near Tiverton, Ontario;
- a 62 per cent interest in the Baie-des-Sables, Anse-à-Valleau and Carleton wind farms, three of five planned wind farms in Gaspé, Québec (Cartier Wind);
- a 60 per cent interest in an underground natural gas storage facility near Crossfield, Alberta (CrossAlta); and
- a 50 per cent interest in a natural gas-fired, combined-cycle cogeneration plant in Toronto, Ontario (Portlands Energy).

TransCanada also has long-term power purchase arrangements (PPA) in place for:

- 100 per cent of the production of the Sundance A power facilities and, through a partnership, 50 per cent of the production of the Sundance B power facilities near Wabamun, Alberta; and
- 756 megawatts (MW) of the generating capacity from the Sheerness power facility near Hanna, Alberta.

TransCanada has interests in the following Energy projects under construction or development:

- a natural gas-fired, combined-cycle power plant under construction near Toronto, Ontario (Halton Hills);
- a natural gas-fired, simple-cycle peaking power plant under construction in Coolidge, Arizona (Coolidge);
- the second phase of the two-phase Kibby Wind power project under construction;
- a 62 per cent interest in the Gros-Morne and Montagne-Sèche wind farms under construction, the fourth and fifth wind farms in Cartier Wind; and
- a natural gas-fired, combined-cycle power plant in development near Oakville, Ontario (Oakville).

NOTE 2 ACCOUNTING POLICIES

The Company's consolidated financial statements have been prepared by management in accordance with GAAP. Amounts are stated in Canadian dollars unless otherwise indicated. Certain comparative figures have been reclassified to conform with the current year's presentation.

In preparing these financial statements, TransCanada is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses as the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgment in making these estimates and assumptions. In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies summarized below.

Basis of Presentation

The consolidated financial statements include the accounts of TransCanada and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control. To the extent there are interests owned by other parties, the other parties' interests are included in Non-Controlling Interests. TransCanada proportionately consolidates its share of the accounts of joint ventures in which the Company is able to exercise joint control. TransCanada uses the equity method of accounting for investments over which the Company is able to exercise significant influence.

Regulation

The Canadian regulated natural gas pipelines are subject to the authority of the National Energy Board (NEB) of Canada. Effective April 2009, the Alberta System became subject to the authority of the NEB. Prior to that date the Alberta System was regulated by the Alberta Utilities Commission (AUC). The natural gas pipelines and regulated storage assets in the U.S. are subject to the authority of the U.S. Federal Energy Regulatory Commission (FERC). These natural gas transmission operations are regulated with respect to construction, operations and the determination of tolls. The timing of recognition of certain revenues and expenses in these regulated businesses may differ from that otherwise expected under GAAP to appropriately reflect the economic impact of the regulators' decisions regarding revenues and tolls.

Revenue Recognition

Pipelines

In the Pipelines segment, revenues from Canadian operations subject to rate regulation are recognized in accordance with decisions made by the NEB. Revenues from U.S. operations subject to rate regulation are recorded in accordance with FERC rules and regulations. The Company's natural gas pipeline revenues are generally based on quantity of gas delivered or contracted capacity. Revenues are recognized on firm contracted capacity over the contract period. For interruptible or volumetric-based services, revenues are recorded when physical delivery is made. The Company's natural gas pipelines that are subject to rate proceedings may have to refund a portion of the revenues they collect depending on the outcome of future rate proceedings. Revenues from non-regulated operations are recorded when products have been delivered or services have been performed.

Energy

i) Power

Revenues from the Company's power business are primarily derived from the sale of electricity through energy marketing activities and from the sale of unutilized natural gas fuel, which are recorded at the time of delivery. Revenues also include capacity payments and ancillary services, which are earned monthly, and revenues earned through the use of energy derivative contracts. The accounting for energy derivative contracts is described in the Financial Instruments section of this note.

ii) Natural Gas Storage

Revenues earned from providing natural gas storage services are recognized in accordance with the terms of the natural gas storage contracts. Revenues earned on the sale of proprietary natural gas are recorded in the month of delivery. Forward contracts for the purchase or sale of natural gas, as well as proprietary natural gas inventory held in storage, are recorded at fair value with changes in fair value recorded in Revenues.

Cash and Cash Equivalents

The Company's cash and cash equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

Inventories

Inventories primarily consist of materials and supplies, including spare parts, and fuel, and are carried at the lower of average cost and net realizable value. The Company values its proprietary natural gas inventory held in storage at fair value, as measured by a weighted average of forward prices for the following four months less selling costs. To record inventory at fair value, TransCanada has designated its natural gas storage business as a broker/trader business that purchases and sells natural gas on a back-to-back basis. The Company records its net proprietary natural gas storage sales and purchases in Revenues. All changes in the fair value of proprietary natural gas inventory held in storage are reflected in Inventories and Revenues.

Plant, Property and Equipment

Pipelines
Plant, property and equipment of the Pipelines segment are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and compression equipment are depreciated at annual rates ranging from one per cent to 25 per cent and metering and other plant equipment are depreciated at various rates. The cost of regulated pipelines includes an allowance for funds used during construction (AFUDC) consisting of a debt component and an equity component based on the rate of return on rate base approved by regulators. This allowance is reflected as an increase in the cost of the assets on the Balance Sheet. Interest is capitalized during construction of non-regulated pipelines. The equity component of AFUDC is a non-cash expenditure.

When regulated pipelines retire plant, property and equipment from service, the original book cost is removed from the gross plant amount and recorded as a reduction to Accumulated Depreciation. Costs incurred to remove a plant from service, net of any salvage proceeds, are also recorded in Accumulated Depreciation.

Energy
Major power generation and natural gas storage plant, equipment and structures in the Energy segment are recorded at cost and depreciated once the assets are ready for their intended use on a straight-line basis over estimated service lives at average annual rates ranging from two per cent to ten per cent. Nuclear power generation assets under capital lease are recorded initially at the present value of minimum lease payments at the inception of the lease and amortized on a straight-line basis over the shorter of their useful life and the remaining lease term. Other equipment is depreciated at various rates. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives. Interest is capitalized on facilities under construction.

Corporate
Corporate plant, property and equipment are recorded at cost and depreciated on a straight-line basis over estimated useful lives at average annual rates ranging from three to 20 per cent.

Impairment of Long-Lived Assets
The Company reviews long-lived assets such as plant, property and equipment, and intangible assets for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows is less than the carrying value of the assets, an impairment loss is recognized for the excess of the carrying value over the fair value of the assets.

Acquisitions and Goodwill
The Company accounts for business acquisitions using the purchase method of accounting and, accordingly, the assets and liabilities of the acquired entities are recorded at their estimated fair value at the date of acquisition. Goodwill is not amortized and is tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset might be impaired. An initial assessment is made by comparing the fair value of the operations, which includes goodwill, to the book value of each reporting unit. If the fair value is less than book value, an impairment is indicated and a second test is performed to measure the amount of the impairment. In the second test, the implied fair value of the goodwill is calculated by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of the goodwill exceeds the calculated implied fair value of the goodwill, an impairment charge is recorded.

Power Purchase Arrangements
A PPA is a long-term contract for the purchase or sale of power on a predetermined basis. The initial payments for the PPAs were deferred and amortized on a straight-line basis over the term of the contracts, which expire in 2017 and 2020. The PPAs under which TransCanada buys power are accounted for as operating leases. A portion of these PPAs has been subleased to third parties under similar terms and conditions. The subleases are accounted for as operating leases and TransCanada records the margin earned from the subleases as a component of Revenues.

Stock Options
TransCanada's Stock Option Plan permits options to be awarded to certain employees, including officers, to purchase common shares. The contractual life of options granted in 2003 and thereafter and options granted prior to 2003 is seven years and ten years, respectively. The Company uses the Black-Scholes model to determine fair value of the options on their grant date. Options may be exercised at a price determined at the time the option is awarded and vest 33.3 per cent on the anniversary date in each of the three years following the award. Forfeiture of stock options results from their expiration or upon resignation or retirement of the option holder or upon termination of the option holder's employment. Stock options become null and void upon forfeiture. The Company records compensation expense over the

three year vesting period, assuming a 15 per cent forfeiture rate, with an offset to Contributed Surplus. This charge is reflected in the results of Corporate. Upon exercise of stock options, adjusted for stock options forfeited, amounts originally recorded against Contributed Surplus are reclassified to Common Shares.

Income Taxes

The Company uses the liability method of accounting for income taxes, which requires the recognition of future income tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future income tax assets and liabilities are measured using enacted or substantively enacted tax rates at the Balance Sheet date that are anticipated to apply to taxable income in the years in which temporary differences are anticipated to be recovered or settled. Changes to these balances are recognized in income in the period during which they occur.

Prior to January 1, 2009, the Company used the taxes payable method of accounting for income taxes for tollmaking purposes for Canadian regulated natural gas transmission operations, as prescribed by regulators. This method was also used for accounting purposes as permitted by GAAP, since there was a reasonable expectation that future taxes payable would be included in future costs of service and recorded in revenues at that time. The liability method of accounting for income taxes continues to be used for all of the Company's other operations.

Canadian income taxes are not provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future.

Foreign Currency Translation

The Company's foreign operations are self-sustaining and are translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated at period-end exchange rates and items included in the Consolidated Statements of Income, Shareholders' Equity, Comprehensive Income, Accumulated Other Comprehensive Income and Cash Flows are translated at the exchange rates in effect at the time of the transaction. Translation adjustments are reflected in Other Comprehensive Income.

Exchange gains or losses on monetary assets and liabilities are recorded in income except for exchange gains or losses on the principal amounts of foreign currency debt related to the Alberta System, Foothills and Canadian Mainline, which are deferred until they are refunded or recovered in tolls, as permitted by regulatory bodies.

Financial Instruments

The Company initially records all financial instruments on the Balance Sheet at their fair value. Subsequent measurement of the financial instruments is based on their classification. Financial assets are classified into the following categories: held for trading, available for sale, held-to-maturity investments and loans and receivables. Financial liabilities are classified as held for trading or other financial liabilities.

Held-for-trading derivative financial assets and liabilities consist of swaps, options, forwards and futures. A financial asset or liability may be designated as held for trading when it is entered into with the intention of generating a profit. The Company has not designated any non-derivative financial assets or liabilities as held for trading. Commodity held-for-trading financial instruments are initially recorded at their fair value and changes to fair value are included in Revenues. Changes in the fair value of interest rate and foreign exchange rate held-for-trading instruments are recorded in Interest Expense and in Interest Income and Other, respectively. Realized gains and losses are included in the same financial category as their underlying position upon settlement of the financial instrument.

The available-for-sale classification includes non-derivative financial assets that are designated as available for sale or are not included in any of the other three classifications. TransCanada's available-for-sale financial instruments include fixed-income securities held for self-insurance. These instruments are accounted for initially at their fair value and changes to fair value are recorded through Other Comprehensive Income. Income from the settlement of available-for-sale financial assets is included in Interest Income and Other.

The held-to-maturity classification consists of non-derivative financial assets that are accounted for at their amortized cost using the effective interest method. The Company does not have any held-to-maturity financial assets.

Trade receivables, loans and other receivables with fixed or determinable payments that are not quoted in an active market are classified as "loans and receivables" and are measured at amortized cost using the effective interest method, net of any impairment. The Company's loans and receivables include trade accounts receivable, interest and non-interest-bearing third-party loans and notes receivable. Interest and other income earned from these financial assets are recorded in Interest Income and Other.

Other financial liabilities consist of liabilities not classified as held for trading. Items in this financial instrument category are recognized at amortized cost using the effective interest method. Interest expense is included in Interest Expense and in Interest Expense of Joint Ventures.

The Company uses derivatives and other financial instruments to manage its exposure to changes in foreign currency exchange rates, interest rates and energy commodity prices. The Company also uses a combination of derivatives and U.S. dollar-denominated debt to manage the foreign currency exposure of its foreign operations.

All derivatives are recorded on the Balance Sheet at fair value, with the exception of non-financial derivatives that were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's expected purchase, sale or usage requirements. Changes in fair value of derivatives that are not designated in a hedging relationship are recorded in Net Income. Derivatives used in hedging relationships are discussed further in the Hedges section of this note.

Derivatives embedded in other financial instruments or contracts (host instrument) are recorded as separate derivatives and are measured at fair value if the economic characteristics of the embedded derivative are not closely related to the host instrument, the terms of the embedded derivative are the same as those of a stand-alone derivative and the total contract is not held for trading or accounted for at fair value. Changes in the fair value of embedded derivatives that are recorded separately are included in Net Income.

The recognition of gains and losses on the derivatives for the Alberta System, Foothills and Canadian Mainline exposures is determined through the regulatory process. The gains and losses on derivatives accounted for as part of rate-regulated accounting are deferred in Regulatory Assets or Regulatory Liabilities.

Transaction costs are defined as incremental costs that are directly attributable to the acquisition, issue or disposal of a financial instrument. The Company offsets long-term debt transaction costs against the associated debt and amortizes these costs using the effective interest method for all costs except those related to the Canadian regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of tolling mechanisms.

The Company records the fair value of its portion of material joint and several guarantees. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees. Guarantees are recorded as an increase to an investment account, Property, Plant and Equipment or a charge to Net Income, and a corresponding liability is recorded in Deferred Amounts.

Hedges

The Company applies hedge accounting to arrangements that qualify for hedge accounting treatment, which include fair value and cash flow hedges, and hedges of foreign currency exposures of net investments in self-sustaining foreign operations. Documentation is prepared at the inception of each hedging arrangement in order to qualify for hedge accounting treatment. In addition, the Company performs an assessment of effectiveness at the inception of the contract and at each reporting date. Hedge accounting is discontinued prospectively when the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk. The changes in fair value are recognized in Net Income. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item, which are also recorded in Net Income. Changes in the fair value of foreign exchange and interest rate fair value hedges are recorded in Interest Income and Other and Interest Expense, respectively. When hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to Net Income over the remaining term of the original hedging relationship.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is initially recognized in Other Comprehensive Income, while any ineffective portion is recognized in Net Income in the same financial category as the underlying transaction. When hedge accounting is discontinued, the amounts recognized previously in Accumulated Other Comprehensive Income are reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, during the periods when the variability in cash flows of the hedged item affects Net Income or as the original hedged item settles. Gains and losses on derivatives are reclassified immediately to Net Income from Accumulated Other Comprehensive Income when the hedged item is sold or terminated early, or when an anticipated transaction is no longer expected to occur.

The Company also enters into cash flow hedges and fair value hedges for activities subject to rate regulation. The gains and losses arising from changes in the fair value of these hedges can be recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as rate-regulated assets or liabilities on behalf of the ratepayers. When the hedges are settled, the realized gains or losses are collected from or refunded to the ratepayers in subsequent years.

In hedging the foreign currency exposure of a net investment in a self-sustaining foreign operation, the effective portion of foreign exchange gains and losses on the hedging instruments is recognized in Other Comprehensive Income and the ineffective portion is recognized in Net Income. The amounts recognized previously in Accumulated Other Comprehensive Income are reclassified to Net Income in the event the Company settles its hedging instruments or reduces its investment in a foreign operation.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred, when a legal obligation exists and a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset and the liability is accreted at the end of each period through charges to operating expenses.

The scope and timing of asset retirements related to regulated natural gas pipelines and hydroelectric power plants is uncertain. As a result, the Company has not recorded an amount for asset retirement obligations related to these assets, with the exception of certain abandoned facilities. With respect to the nuclear assets leased by Bruce Power, the Company has not recorded an amount for asset retirement obligations, as Bruce Power leases the assets and the lessor is responsible for decommissioning liabilities under the lease agreement.

Environmental Liabilities

The Company records liabilities on an undiscounted basis for environmental remediation efforts that are likely to occur and where the cost can be reasonably estimated. The estimates, including associated legal costs, are based on available information using existing technology and enacted laws and regulations. The estimates are subject to revision in future periods based on actual costs incurred or new circumstances. Amounts expected to be recovered from other parties, including insurers, are recorded as an asset separate from the associated liability.

Emission allowances or credits purchased for compliance are recorded on the Balance Sheet at historical cost and expensed when they are retired. Compliance payments are expensed when incurred. Allowances granted to or internally generated by TransCanada are not attributed a value for accounting purposes. When required, TransCanada accrues emission liabilities on the Balance Sheet upon the generation or sale of power using the best estimate of the amount required to settle the obligation. Allowances or credits not used for compliance are sold and recorded in Revenues.

Employee Benefit and Other Plans

The Company sponsors defined benefit pension plans (DB Plans), defined contribution plans (DC Plans), a Savings Plan and other post-employment benefit plans. Contributions made by the Company to the DC Plans and Savings Plan are expensed when incurred. The cost of the DB Plans and other post-employment benefits received by employees is actuarially determined using the projected benefit method pro-rated based on service and management's best estimate of expected plan investment performance, salary escalation, retirement age of employees and expected health care costs.

The DB Plans' assets are measured at fair value. The expected return on the DB Plans' assets is determined using market-related values based on a five year moving average value for all of the DB Plans' assets. Past service costs are amortized over the expected average remaining service life of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The excess of net actuarial gains or losses over ten per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized over the average remaining service period of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

The Company has medium-term incentive plans, under which payments are made to eligible employees. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, benefits vest when certain conditions are met, including the employees' continued employment during a specified period and achievement of specified corporate performance targets.

Certain of the Company's joint ventures sponsor DB Plans. The Company records its proportionate share of expenses, funding contributions and accrued benefit assets and liabilities related to these plans.

NOTE 3 ACCOUNTING CHANGES

Changes in Accounting Policies for 2009

Rate-Regulated Operations

Effective January 1, 2009, the temporary exemption was withdrawn from the Canadian Institute of Chartered Accountants (CICA) Handbook Section 1100 "Generally Accepted Accounting Principles", which permitted the recognition and measurement of assets and liabilities arising from rate regulation. In addition, Section 3465 "Income Taxes" was amended to require the recognition of future income tax assets and liabilities for rate-regulated operations. In accordance with the CICA Handbook accounting hierarchy, the Company chose to adopt accounting policies consistent with the U.S. Financial Accounting Standards Board's (FASB) Accounting Standards Codification (ASC) Topic 980 "Regulated Operations". As a result, TransCanada retained its current method of accounting for its rate-regulated operations, except that the Company is required to recognize future income tax assets and liabilities, instead of using the taxes payable method, and records an offsetting adjustment to regulatory assets and liabilities. As a result of adopting this accounting change, additional future income tax liabilities and a regulatory asset in the amount of $1.4 billion were recorded January 1, 2009 in each of Future Income Taxes and Regulatory Assets.

Adjustments to the 2009 financial statements have been made in accordance with the transitional provisions for Section 3465, which required a cumulative adjustment in the current period to Future Income Taxes and Regulatory Assets. Restatement of prior periods' financial statements was not permitted under Section 3465.

Goodwill and Intangible Assets
Effective January 1, 2009, the Company adopted CICA Handbook Section 3064 "Goodwill and Intangible Assets", which replaced Section 3062 "Goodwill and Other Intangible Assets". Section 3064 gives guidance on the recognition of intangible assets and on the recognition and measurement of internally developed intangible assets. In addition, Section 3450 "Research and Development Costs" was withdrawn from the CICA Handbook. Adopting this accounting change did not have a material effect on the Company's financial statements.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities
Effective January 1, 2009, the Company adopted the accounting provisions of Emerging Issues Committee (EIC) Abstract EIC 173, "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". Under EIC 173 an entity's own credit risk and the credit risk of its counterparties are taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments. Adopting this accounting change did not have a material effect on the Company's financial statements.

Future Accounting Changes

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests
The CICA Handbook Section 1582 "Business Combinations" is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting the standard is expected to have a material effect on the way the Company accounts for future business combinations. Entities adopting Section 1582 will also be required to adopt CICA Handbook Sections 1601 "Consolidated Financial Statements" and 1602 "Non-Controlling Interests". These standards will require non-controlling interests to be presented as part of Shareholders' Equity on the balance sheet. In addition, the income statement of the controlling parent will include 100 per cent of the subsidiary's results and present the allocation between the controlling and non-controlling interests. These standards will be effective January 1, 2011, with early adoption permitted. The changes resulting from adopting Section 1582 will be applied prospectively and the changes from adopting Sections 1601 and 1602 will be applied retrospectively.

International Financial Reporting Standards
The CICA's Accounting Standards Board announced that Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. Effective January 1, 2011, the Company will begin reporting under IFRS.

TransCanada currently follows specific accounting policies unique to a rate-regulated business. TransCanada has established a project team to support adopting IFRS. The project team is actively monitoring developments regarding potential future guidance on the applicability of certain aspects of rate-regulated accounting under IFRS. Developments in this area could have a significant effect on the scope of the Company's IFRS project and on TransCanada's financial results under IFRS. On July 23, 2009, the IASB issued an exposure draft "Rate-regulated Activities". The Company is assessing the impact of developments related to the exposure draft.

As a result of proposed changes to certain IFRS, together with the current stage of the Company's IFRS project, TransCanada cannot reasonably quantify the full impact that adopting IFRS will have on its financial position and future results.

NOTE 4 SEGMENTED INFORMATION

Effective January 1, 2009, TransCanada revised its presentation of certain income and expense items in the Consolidated Statement of Income to better reflect the operating and financing structure of the Company. To conform with the new presentation, certain of the income and expense amounts pertaining to operations that were previously classified on the Consolidated Income Statement as Other Expenses/(Income) are now included in Operating and Other Expenses/(Income). Depreciation expense has been redefined as Depreciation and Amortization expense and includes amortization of $58 million in 2009 (2008 and 2007 – $58 million), for PPAs, which was previously included in Commodity Purchases Resold. Support services costs previously allocated to Pipelines and Energy of $112 million in 2009 (2008 – $106 million; 2007 – $97 million) are now included in Corporate. In addition, amounts related to Interest Expense and Interest Expense of Joint Ventures, Interest Income and Other, Income Taxes and Non-Controlling Interests are no longer reported on a segmented basis. Segmented information has been retroactively reclassified to reflect these changes. These changes had no impact on reported consolidated Net Income.

Year ended December 31, 2009 (millions of dollars)	**Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	**4,729**	**4,237**	**–**	**8,966**
Plant operating costs and other	**(1,655)**	**(1,595)**	**(117)**	**(3,367)**
Commodity purchases resold	**–**	**(1,511)**	**–**	**(1,511)**
Other income	**48**	**1**	**–**	**49**
	3,122	**1,132**	**(117)**	**4,137**
Depreciation and amortization	**(1,030)**	**(347)**	**–**	**(1,377)**
	2,092	**785**	**(117)**	**2,760**
Interest expense				**(954)**
Interest expense of joint ventures				**(64)**
Interest income and other				**121**
Income taxes				**(387)**
Non-controlling interests				**(96)**
Net Income				**1,380**
Preferred share dividends				**(6)**
Net Income Applicable to Common Shares				**1,374**

Year ended December 31, 2008 (millions of dollars)	**Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	4,650	3,969	–	8,619
Plant operating costs and other	(1,645)	(1,259)	(110)	(3,014)
Commodity purchases resold	–	(1,501)	–	(1,501)
Calpine bankruptcy settlements	279	–	–	279
Writedown of Broadwater LNG project costs	–	(41)	–	(41)
Other income	31	1	6	38
	3,315	1,169	(104)	4,380
Depreciation and amortization	(989)	(258)	–	(1,247)
	2,326	911	(104)	3,133
Interest expense				(943)
Interest expense of joint ventures				(72)
Interest income and other				54
Income taxes				(602)
Non-controlling interests				(130)
Net Income				1,440

Year ended December 31, 2007 (millions of dollars)	**Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	4,712	4,116	–	8,828
Plant operating costs and other	(1,590)	(1,336)	(104)	(3,030)
Commodity purchases resold	(72)	(1,829)	–	(1,901)
Other income	27	19	2	48
	3,077	970	(102)	3,945
Depreciation and amortization	(1,021)	(216)	–	(1,237)
	2,056	754	(102)	2,708
Interest expense				(943)
Interest expense of joint ventures				(75)
Interest income and other				120
Income taxes				(490)
Non-controlling interests				(97)
Net Income				1,223

TOTAL ASSETS

December 31 (millions of dollars)	2009	2008
Pipelines	**29,508**	25,020
Energy	**12,477**	12,006
Corporate	**1,856**	2,388
	43,841	39,414

GEOGRAPHIC INFORMATION

Year ended December 31 (millions of dollars)	2009	2008	2007
Revenues[1]			
Canada – domestic	**5,177**	4,599	5,019
Canada – export	**756**	1,125	1,006
United States and other	**3,033**	2,895	2,803
	8,966	8,619	8,828

(1) Revenues are attributed based on the country in which the product or service originated.

December 31 (millions of dollars)	2009	2008
Plant, Property and Equipment		
Canada	**20,266**	18,041
United States	**12,441**	10,973
Mexico	**172**	175
	32,879	29,189

CAPITAL EXPENDITURES

Year ended December 31 (millions of dollars)	2009	2008	2007
Pipelines	**3,904**	1,854	564
Energy	**1,487**	1,266	1,079
Corporate	**26**	14	8
	5,417	3,134	1,651

NOTE 5 PLANT, PROPERTY AND EQUIPMENT

	2009			2008		
December 31 (millions of dollars)	**Cost**	**Accumulated Depreciation**	**Net Book Value**	Cost	Accumulated Depreciation	Net Book Value
Pipelines[1]						
Canadian Mainline						
Pipeline	**8,752**	**4,501**	**4,251**	8,740	4,269	4,471
Compression	**3,379**	**1,529**	**1,850**	3,373	1,399	1,974
Metering and other	**364**	**153**	**211**	344	140	204
	12,495	**6,183**	**6,312**	12,457	5,808	6,649
Under construction	**27**	**–**	**27**	16	–	16
	12,522	**6,183**	**6,339**	12,473	5,808	6,665
Alberta System						
Pipeline	**6,002**	**2,777**	**3,225**	5,518	2,637	2,881
Compression	**1,696**	**983**	**713**	1,552	914	638
Metering and other	**879**	**342**	**537**	846	317	529
	8,577	**4,102**	**4,475**	7,916	3,868	4,048
Under construction	**281**	**–**	**281**	354	–	354
	8,858	**4,102**	**4,756**	8,270	3,868	4,402
ANR						
Pipeline	**848**	**79**	**769**	976	69	907
Compression	**489**	**65**	**424**	579	61	518
Metering and other	**646**	**67**	**579**	686	50	636
	1,983	**211**	**1,772**	2,241	180	2,061
Under construction	**23**	**–**	**23**	31	–	31
	2,006	**211**	**1,795**	2,272	180	2,092
GTN[2]						
Pipeline	**1,135**	**205**	**930**	1,482	215	1,267
Compression	**414**	**59**	**355**	562	63	499
Metering and other	**93**	**22**	**71**	134	23	111
	1,642	**286**	**1,356**	2,178	301	1,877
Under construction	**22**	**–**	**22**	30	–	30
	1,664	**286**	**1,378**	2,208	301	1,907
Keystone – under construction	**5,305**	**–**	**5,305**	1,361	–	1,361
Joint Ventures and Others						
Great Lakes	**1,608**	**694**	**914**	1,875	744	1,131
Foothills	**1,645**	**917**	**728**	1,655	873	782
Northern Border	**1,316**	**613**	**703**	1,530	682	848
Other[2][3]	**2,307**	**587**	**1,720**	2,078	566	1,512
	6,876	**2,811**	**4,065**	7,138	2,865	4,273
	37,231	**13,593**	**23,638**	33,722	13,022	20,700
Energy						
Nuclear[4]	**1,769**	**451**	**1,318**	1,604	364	1,240
Natural gas – Ravenswood	**1,712**	**82**	**1,630**	1,977	22	1,955
Natural gas – Other[5][6]	**2,032**	**522**	**1,510**	1,702	504	1,198
Hydro	**625**	**56**	**569**	628	48	580
Wind[7]	**611**	**41**	**570**	391	18	373
Natural gas storage	**418**	**56**	**362**	374	46	328
Other	**156**	**89**	**67**	156	82	74
	7,323	**1,297**	**6,026**	6,832	1,084	5,748
Under construction – Nuclear[8]	**1,845**	**–**	**1,845**	1,463	–	1,463
Under construction – Other[9]	**1,287**	**–**	**1,287**	1,224	–	1,224
	10,455	**1,297**	**9,158**	9,519	1,084	8,435
Corporate	**110**	**27**	**83**	74	20	54
	47,796	**14,917**	**32,879**	43,315	14,126	29,189

(1) In 2009, the Company capitalized $33 million (2008 – $27 million) relating to the equity portion of AFUDC on natural gas pipelines.

(2) GTN's results include North Baja until July 1, 2009 when it was sold to PipeLines LP.

(3) Pipelines – Other includes assets of Portland, Iroquois, TQM, North Baja, Tamazunchale, Ventures LP and Tuscarora, and expenditures of $200 million (2008 – nil) and $29 million (2008 – nil) for the construction of Bison and Guadalajara, respectively.

(4) Includes assets under capital lease relating to Bruce Power.

(5) Includes facilities with long-term PPAs that are accounted for as operating leases. The cost and accumulated depreciation of these facilities were $93 million and $17 million, respectively, at December 31, 2009 (2008 – $90 million and $13 million, respectively). Revenues of $15 million were recognized in 2009 (2008 – $14 million; 2007 – $16 million) through the sale of electricity under the related PPAs.

(6) Includes Portlands Energy as of April 2009.

(7) Includes phase one of Kibby Wind as of October 30, 2009.

(8) Nuclear assets under construction primarily includes expenditures for the refurbishment and restart of Bruce A.

(9) Other Energy assets under construction at December 31, 2009 includes expenditures for the construction of Halton Hills, Coolidge, the second phase of Kibby Wind and two Cartier wind farms, Gros-Morne and Montagne-Sèche.

NOTE 6 GOODWILL

The Company has recorded the following goodwill on its acquisitions in the U.S.:

(millions of dollars)	Pipelines	Energy	Total
Balance at January 1, 2008	2,633	–	2,633
Acquisition of Ravenswood	–	949	949
Foreign exchange and adjustments	749	66	815
Balance at December 31, 2008	3,382	1,015	4,397
Foreign exchange and adjustments	**(491)**	**(143)**	**(634)**
Balance at December 31, 2009	**2,891**	**872**	**3,763**

NOTE 7 INTANGIBLES AND OTHER ASSETS

December 31 (millions of dollars)	**2009**	2008
PPAs(1)	**593**	651
Deferred project development costs(2)	**470**	116
Loans and advances(3)(4) (Note 24)	**417**	140
Pension and other benefit plans (Note 22)	**383**	234
Fair value of derivative contracts (Note 18)	**260**	191
Equity investments(5)	**84**	85
Prepaid operating lease(3)	**–**	369
Other	**293**	241
	2,500	2,027

(1) The following amounts related to PPAs are included in the consolidated financial statements:

	2009			2008		
December 31 (millions of dollars)	**Cost**	**Accumulated Amortization**	**Net Book Value**	Cost	Accumulated Amortization	Net Book Value
PPAs	**915**	**322**	**593**	915	264	651

Amortization expense for the PPAs was $58 million for the year ended December 31, 2009 (2008 and 2007 – $58 million). The expected annual amortization expense in each of the next five years is: 2010 – $58 million; 2011 – $57 million; 2012 – $57 million; 2013 – $57 million; and 2014 – $57 million.

(2) The balance of $470 million at December 31, 2009 (2008 – $74 million) related to the proposed expansion of Keystone. The balance at December 31, 2008 included $42 million related to the Bison pipeline project, which was included in Plant, Property and Equipment in 2009. In 2008, TransCanada wrote down $41 million of capitalized costs related to the Broadwater liquefied natural gas (LNG) project after the New York Department of State rejected a proposal to construct this facility. Annual project development expenditures are included in Deferred Amounts and Other in Consolidated Cash Flows.

(3) Upon acquisition of Ravenswood in August 2008, an operating lease was prepaid in the amount of $322 million. Pursuant to the terms of the Ravenswood acquisition agreement in March 2009, TransCanada also acquired the lessor entity, thereby eliminating the prepaid

operating lease upon consolidation. As at December 31, 2009, TransCanada held a $317 million note receivable from the August 2008 seller of Ravenswood which bears interest at 6.75 per cent and matures in 2039. Loans and advances includes $274 million representing the long-term portion of this note receivable.

(4) As at December 31, 2009, loans and advances includes a $143 million (2008 – $140 million) loan to the APG to finance its one-third share of project development costs related to the Mackenzie Gas Pipeline project. The ability to recover this investment remains dependent upon a successful outcome of the project.

(5) The balance primarily relates to the Company's 46.5 per cent ownership interest in TransGas.

NOTE 8 JOINT VENTURE INVESTMENTS

		TransCanada's Proportionate Share				
	Ownership Interest as at December 31,	Income/(Loss) Before Income Taxes Year Ended December 31			Net Assets December 31	
(millions of dollars)	2009	**2009**	2008	2007	**2009**	2008
Pipelines						
Northern Border[1]		**47**	59	67	**420**	479
Iroquois	44.5%	**44**	32	25	**183**	239
TQM	50.0%	**22**	12	11	**82**	69
Keystone[2]		**–**	(7)	n/a[3]	**–**	906
Great Lakes[4]		**–**	–	13	**–**	–
Other	Various	**17**	15	13	**56**	70
Energy						
Bruce A	48.8%	**3**	46	8	**2,386**	2,012
Bruce B	31.6%	**236**	136	140	**580**	429
CrossAlta	60.0%	**55**	44	59	**77**	56
Cartier Wind[5]	62.0%	**26**	12	10	**327**	365
Portlands Energy[6]	50.0%	**24**	–	–	**358**	334
Other	Various	**4**	9	5	**99**	101
		478	358	351	**4,568**	5,060

(1) The results reflect a 50 per cent interest in Northern Border as a result of the Company fully consolidating PipeLines LP. Through TransCanada's 38.2 per cent (2008 and 2007 – 32.1 per cent) ownership interest in PipeLines LP, its effective ownership of Northern Border, net of non-controlling interests, was 19.1 per cent at December 31, 2009 (2008 and 2007 – 16.1 per cent).

(2) In August 2009, TransCanada purchased ConocoPhillips' remaining ownership interest in Keystone of approximately 20 per cent, increasing TransCanada's ownership interest to 100 per cent. As of the acquisition date, the Company began fully consolidating Keystone on a prospective basis. At December 31, 2008, TransCanada's equity ownership in the Keystone partnerships was 61.9 per cent (December 31, 2007 – 50.0 per cent). Strategic, operational and financial decisions were made jointly with ConocoPhillips until August 2009.

(3) Not applicable, as there were no comparative amounts in 2007.

(4) TransCanada has a direct ownership interest in Great Lakes of 53.6 per cent, and an indirect 17.7 per cent interest (2008 and 2007 – 14.9 per cent) through its 38.2 per cent (2008 and 2007 – 32.1 per cent) ownership interest in PipeLines LP. The Company's total effective ownership interest in Great Lakes, net of non-controlling interests, was 71.3 per cent at December 31, 2009 (2008 and 2007 – 68.5 per cent). TransCanada commenced consolidating its investment in Great Lakes on a prospective basis effective February 2007.

(5) TransCanada proportionately consolidates its 62 per cent interest in the Cartier Wind assets. The second and third phases of the five-phase Cartier Wind project, Anse-à-Valleau and Carleton, began operating in November 2007 and 2008, respectively.

(6) Portlands Energy began operating in April 2009.

Summarized Financial Information of Joint Ventures

Year ended December 31 (millions of dollars)	**2009**	2008	2007
Income			
Revenues	**1,418**	1,264	1,305
Plant operating costs and other	**(676)**	(683)	(736)
Depreciation and amortization	**(196)**	(154)	(150)
Interest expense and other	**(68)**	(69)	(68)
Proportionate Share of Joint Venture Income Before Income Taxes	**478**	358	351

Year ended December 31 (millions of dollars)	**2009**	2008	2007
Cash Flows			
Operating activities	**203**	389	59
Investing activities	**(399)**	(1,754)	(400)
Financing activities[1]	**130**	1,353	409
Effect of foreign exchange rate changes on cash and cash equivalents	**(17)**	23	(8)
Proportionate Share of (Decrease)/Increase in Cash and Cash Equivalents of Joint Ventures	**(83)**	11	60

(1) Financing activities included cash outflows resulting from distributions paid to TransCanada of $252 million in 2009 (2008 – $287 million; 2007 – $361 million) and cash inflows resulting from capital contributions paid by TransCanada of $864 million in 2009 (2008- $1,170 million; 2007 – $771 million).

December 31 (millions of dollars)	**2009**	2008
Balance Sheet		
Cash and cash equivalents	**98**	181
Other current assets	**552**	560
Plant, property and equipment	**5,239**	6,341
Intangibles and other assets/(deferred amounts), net	**5**	45
Current liabilities	**(572)**	(1,196)
Long-term debt	**(753)**	(869)
Future income taxes	**(1)**	(2)
Proportionate Share of Net Assets of Joint Ventures	**4,568**	5,060

NOTE 9 ACQUISITIONS AND DISPOSITIONS

Pipelines

Keystone
In August 2009, TransCanada purchased ConocoPhillips' remaining ownership interest in Keystone of approximately 20 per cent for US$553 million plus the assumption of US$197 million of short-term debt. The acquisition increased TransCanada's ownership interest in Keystone to 100 per cent and was recorded in Plant, Property and Equipment. The purchase price reflected ConocoPhillips' capital contributions to date and included capitalization of interest during construction. TransCanada began fully consolidating Keystone into its Pipelines segment upon acquisition.

In 2008, TransCanada entered into an agreement with ConocoPhillips to increase its equity ownership in Keystone to approximately 80 per cent from 50 per cent, with ConocoPhillips' equity ownership in Keystone being reduced concurrently to approximately 20 per cent from 50 per cent. In 2008 and prior to August 2009, TransCanada funded 100 per cent of the construction expenditures until the participants' project capital contributions were aligned with their revised ownership interests. In 2009, prior to August, TransCanada funded $1.3 billion of cash calls for Keystone, resulting in the Company acquiring an incremental increase in ownership of approximately 18 per cent for $313 million. In 2008, the Company funded $362 million of cash calls, resulting in an incremental increase in ownership of approximately 12 per cent for $176 million. TransCanada's ownership interest was approximately 80 per cent and 62 per cent in August 2009 and December 31, 2008, respectively. TransCanada proportionately consolidated the Keystone partnerships prior to August 2009.

During 2008, Keystone purchased pipeline facilities located in Saskatchewan and Manitoba from the Canadian Mainline for use in the construction of the Keystone oil pipeline. The sale was completed in three phases for total proceeds of $67 million, with no gain recognized on the sale.

ANR and Great Lakes
On February 22, 2007, TransCanada acquired from El Paso Corporation 100 per cent of ANR and an additional 3.6 per cent interest in Great Lakes for a total of US$3.4 billion, including US$491 million of assumed long-term debt. The acquisitions were accounted for using the purchase method of accounting. TransCanada began consolidating ANR and Great Lakes into the Pipelines segment upon acquisition. The purchase price was allocated as follows:

Purchase Price Allocation

(millions of US dollars)	ANR	Great Lakes	Total
Current assets	250	4	254
Plant, property and equipment	1,617	35	1,652
Other non-current assets	83	–	83
Goodwill	1,945	32	1,977
Current liabilities	(179)	(3)	(182)
Long-term debt	(475)	(16)	(491)
Other non-current liabilities	(357)	(19)	(376)
	2,884	33	2,917

TC PipeLines, LP Acquisition of Interest in Great Lakes
On February 22, 2007, PipeLines LP acquired from El Paso Corporation a 46.4 per cent interest in Great Lakes for US$942 million, including US$209 million of assumed long-term debt. The acquisition was accounted for using the purchase method of accounting. TransCanada began consolidating Great Lakes into its Pipelines segment after the acquisition date.

The purchase price was allocated as follows:

Purchase Price Allocation

(millions of US dollars)	
Current assets	42
Plant, property and equipment	465
Other non-current assets	1
Goodwill	457
Current liabilities	(23)
Long-term debt	(209)
	733

The allocation of the purchase price for these transactions was made using the fair value of the net assets at the date of acquisition. Tolls charged by ANR and Great Lakes are subject to rate regulation based on historical costs. As a result, the regulated net assets, other than ANR's gas held for sale, were determined to have a fair value equal to their rate-regulated value.

Factors that contributed to goodwill included the opportunity to expand further in the U.S. market and to gain a stronger competitive position in the North American gas transmission business. Goodwill related to TransCanada's ANR and Great Lakes transactions is not amortizable for tax purposes. Goodwill related to PipeLines LP's Great Lakes transaction is amortizable for tax purposes.

TC PipeLines, LP

On November 18, 2009, PipeLines LP completed an offering of five million common units at a price of US$38.00 per unit. The issue resulted in net proceeds to PipeLines LP of US$182 million. TransCanada contributed an additional US$3.8 million to maintain its general partnership interest but did not purchase any other units. Upon completion of the offering, the Company's ownership interest in PipeLines LP decreased to 38.2 per cent and the Company recognized a dilution gain of $18 million after tax ($29 million pre-tax).

On July 1, 2009, TransCanada sold North Baja to PipeLines LP. As part of the transaction, TransCanada agreed to amend its general partner incentive distribution rights arrangement with PipeLines LP. TransCanada received aggregate consideration totalling approximately US$395 million from PipeLines LP, including US$200 million in cash and 6,371,680 common units of PipeLines LP. TransCanada recorded no gain or loss as a result of the transaction. TransCanada's ownership in PipeLines LP increased to 42.6 per cent as a result of the transaction. TransCanada's increased ownership in PipeLines LP also resulted in a decrease in Non-Controlling Interests and an increase in Contributed Surplus.

In February 2007, PipeLines LP completed a private placement offering of 17.4 million common units at a price of US$34.57 per unit. TransCanada acquired 50 per cent of the units for US$300 million. TransCanada also invested an additional US$12 million to maintain its general partnership interest in PipeLines LP. As a result of these additional investments, TransCanada's ownership in PipeLines LP was 32.1 per cent on February 22, 2007. The total private placement, together with TransCanada's additional investment, resulted in gross proceeds to PipeLines LP of US$612 million, which were used to partially finance its acquisition of the 46.4 per cent ownership interest in Great Lakes.

Energy

Ravenswood

On August 26, 2008, TransCanada acquired from National Grid plc 100 per cent of the 2,480 MW Ravenswood power facility for US$2.9 billion. The acquisition was accounted for using the purchase method of accounting. TransCanada began consolidating Ravenswood into its Energy segment after the acquisition date. The purchase price was allocated as follows:

Purchase Price Allocation

(millions of US dollars)	
Current assets	128
Plant, property and equipment	1,666
Other non-current assets	305
Goodwill	834
Current liabilities	(11)
Other non-current liabilities	(10)
	2,912

The allocation of the purchase price was made using the fair value of the net assets at the date of acquisition. Factors that contributed to goodwill included the opportunity to expand the Energy segment further into the U.S. market and to gain a stronger competitive position in the North American power generation business. The goodwill recognized on the transaction is amortizable for tax purposes.

Ontario Land Sale

In November 2007, TransCanada's Energy segment sold land in Ontario that had previously been held for development, generating net proceeds of $37 million and recognizing an after tax gain of $14 million on the sale.

NOTE 10 LONG-TERM DEBT

Outstanding loan amounts (millions of dollars)	Maturity Dates	**2009** Outstanding December 31	**2009** Interest Rate(1)	2008 Outstanding December 31	2008 Interest Rate(1)
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian dollars	2010 to 2020	**1,002**	**10.9%**	1,251	10.8%
U.S. dollars (2009 and 2008 – US$600)(2)	2012 to 2021	**626**	**9.5%**	734	9.5%
Medium-Term Notes					
Canadian dollars(3)	2011 to 2039	**4,148**	**6.2%**	3,653	5.3%
Senior Unsecured Notes					
U.S. dollars (2009 – US$6,496; 2008 – US$4,723)(4)	2010 to 2039	**6,727**	**6.7%**	5,751	6.3%
		12,503		11,389	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian dollars	2010 to 2024	**430**	**11.5%**	439	11.5%
U.S. dollars (2009 and 2008 – US$375)	2012 to 2023	**390**	**8.2%**	457	8.2%
Medium-Term Notes					
Canadian dollars	2025 to 2030	**502**	**7.4%**	502	7.4%
U.S. dollars (2009 and 2008 – US$33)	2026	**34**	**7.5%**	39	7.5%
		1,356		1,437	
TRANSCANADA PIPELINE USA LTD.					
Bank Loan					
U.S. dollars (2009 and 2008 – US$700)	2012	**733**	**0.5%**	857	2.4%
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. dollars (2009 – US$443; 2008 – US$444)	2010 to 2025	**462**	**9.1%**	541	9.1%
GAS TRANSMISSION NORTHWEST CORPORATION					
Senior Unsecured Notes					
U.S. Dollars (2009 and 2008 – US$400)	2010 to 2035	**417**	**5.4%**	488	5.4%
TC PIPELINES, LP					
Unsecured Loan					
U.S. dollars (2009 – US$484; 2008 – US$475)	2011	**506**	**1.0%**	580	2.7%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. dollars (2009 – US$411; 2008 – US$430)	2011 to 2030	**429**	**7.8%**	526	7.8%
TUSCARORA GAS TRANSMISSION COMPANY					
Senior Unsecured Notes					
U.S. dollars (2009 – US$57; 2008 – US$64)	2010 to 2012	**60**	**7.3%**	78	7.4%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Secured Notes(5)					
U.S. dollars (2009 – US$180; 2008 – US$196)	2018	**186**	**6.1%**	236	6.1%
OTHER					
Senior Notes					
U.S. dollars (2009 – US$12; 2008 – US$18)	2011	**12**	**7.3%**	22	7.3%
		16,664		16,154	
Less: Current Portion of Long-Term Debt		**478**		786	
		16,186		15,368	

(1) Interest rates are the effective interest rates except for those pertaining to long-term debt issued for the Company's regulated operations, in which case the weighted average interest rate is presented as required by the regulators. Weighted average and effective interest rates are stated as at the respective outstanding dates.

(2) Includes fair value adjustments for interest rate swap agreements on US$50 million of debt at December 31, 2008.

(3) Includes fair value adjustments for interest rate swap agreements on $50 million of debt at December 31, 2008.

(4) Includes fair value adjustments for interest rate swap agreements on US$250 million of debt at December 31, 2009 (2008 – US$150 million).

(5) Senior Secured Notes are secured by shipper transportation contracts, existing and new guarantees, letters of credit and collateral requirements.

Principal Repayments

Principal repayments on the long-term debt of the Company for the next five years are approximately as follows: 2010 – $478 million; 2011 – $923 million; 2012 – $1,176 million; 2013 – $911 million; and 2014 – $968 million.

Debt Shelf Programs – TransCanada PipeLines Limited

In December 2009, TransCanada PipeLines Limited (TCPL) filed a debt base shelf prospectus qualifying for the issuance of up to US$4.0 billion of debt securities in the U.S. This prospectus replaced the debt base shelf prospectus filed in January 2009, discussed below. No amounts have been issued under the December 2009 base shelf prospectus.

In April 2009, TCPL filed a $2.0 billion Canadian Medium-Term Notes base shelf prospectus to replace a March 2007 $1.5 billion Canadian Medium-Term Notes base shelf prospectus, which expired in April 2009. No amounts have been issued under the April 2009 base shelf prospectus.

In January 2009, TCPL filed a debt shelf prospectus in the U.S. qualifying for issuance of US$3.0 billion of debt securities. Subsequent to the January 2009 debt issue discussed below, the Company had US$1.0 billion of remaining capacity available under this debt shelf prospectus.

TransCanada PipeLines Limited

In February 2009, TCPL issued Medium-Term Notes of $300 million and $400 million maturing in February 2014 and February 2039, respectively, and bearing interest at 5.05 per cent and 8.05 per cent, respectively. These notes were issued by way of a pricing supplement under a Canadian $1.5 billion debt base shelf prospectus filed in March 2007.

In January 2009, TCPL issued Senior Unsecured Notes of US$750 million and US$1.25 billion maturing in January 2019 and January 2039, respectively, and bearing interest at 7.125 per cent and 7.625 per cent, respectively. These notes were issued by way of a prospectus supplement under the U.S. debt base shelf prospectus filed in January 2009.

In August 2008, TCPL issued $500 million of Medium-Term Notes maturing in August 2013 and bearing interest at 5.05 per cent by way of a pricing supplement under the Canadian debt base shelf prospectus filed in March 2007.

In August 2008, TCPL issued US$850 million and US$650 million of Senior Unsecured Notes maturing in August 2018 and August 2038, respectively, and bearing interest at 6.50 per cent and 7.25 per cent, respectively. These notes were issued by way of a prospectus supplement under a US$2.5 billion debt base shelf prospectus filed in September 2007, which was fully utilized following these issuances.

NOVA Gas Transmission Ltd.

Debentures issued by NOVA Gas Transmission Ltd. (NGTL) in the amount of $225 million have retraction provisions that entitle the holders to require redemption of up to eight per cent of the then outstanding principal plus accrued and unpaid interest on specified repayment dates. No redemptions were made to December 31, 2009.

TransCanada PipeLine USA Ltd.

TransCanada PipeLine USA Ltd. (TCPL USA) has a US$1.0 billion committed, unsecured, syndicated credit facility, guaranteed by TransCanada, consisting of a US$700 million five year term loan maturing in 2012 and a US$300 million, revolving facility maturing in February 2013 described further under Note 20. Included in Long-Term Debt was an outstanding balance of US$700 million on the term loan at December 31, 2009 and 2008.

TC PipeLines, LP

PipeLines LP has available a committed, unsecured syndicated revolving credit and term loan facility of US$725 million maturing December 2011, consisting of a US$475 million senior term loan and a US$250 million senior revolving credit facility. There was an outstanding balance of US$484 million and US$475 million on the credit facility at December 31, 2009 and 2008, respectively.

Interest Expense

Year ended December 31 (millions of dollars)	**2009**	2008	2007
Interest on long-term debt	**1,212**	970	948
Interest on junior subordinated notes	**73**	68	43
Interest on short-term debt	**10**	32	48
Capitalized interest	**(358)**	(141)	(68)
Amortization and other financial charges(1)	**17**	14	(28)
	954	943	943

(1) Amortization and other financial charges includes amortization of transaction costs and debt discounts calculated using the effective interest method.

The Company made interest payments of $916 million in 2009 (2008 – $833 million; 2007 – $966 million) net of interest capitalized on construction projects.

NOTE 11 LONG-TERM DEBT OF JOINT VENTURES

		2009		2008	
Outstanding loan amounts (millions of dollars)	Maturity Dates	**Outstanding December 31(1)**	**Interest Rate(2)**	Outstanding December 31(1)	Interest Rate(2)
NORTHERN BORDER PIPELINE COMPANY					
Senior Unsecured Notes (2009 – US$175; 2008 – US$225)	2012 to 2021	**182**	**7.2%**	275	7.7%
Bank Facility (2009 – US$108; 2008 – US$96)	2012	**112**	**0.5%**	116	3.4%
IROQUOIS GAS TRANSMISSION SYSTEM, L.P.					
Senior Unsecured Notes (2009 – US$210; 2008 – US$160)	2010 to 2027	**219**	**7.8%**	195	7.6%
BRUCE POWER L.P. AND BRUCE POWER A L.P.					
Capital Lease Obligations	2018	**222**	**7.5%**	235	7.5%
Term Loan	2031	**93**	**7.1%**	95	7.1%
TRANS QUÉBEC & MARITIMES PIPELINE INC.					
Bonds	2010 to 2014	**125**	**5.2%**	137	6.0%
Term Loan	2011	**10**	**0.4%**	18	1.9%
OTHER	2012	**2**	**2.7%**	5	5.5%
		965		1,076	
Less: Current Portion of Long-Term Debt of Joint Ventures		**212**		207	
		753		869	

(1) Amounts outstanding represent TransCanada's proportionate share, except for Northern Border, which reflects a 50 per cent interest as a result of the Company fully consolidating PipeLines LP.

(2) Interest rates are the effective interest rates except those pertaining to long-term debt issued for TQM's regulated operations, in which case the weighted average interest rate is presented as required by the regulators. Weighted average and effective interest rates are stated as at the respective outstanding dates. At December 31, 2008, the effective interest rate resulting from swap agreements was 0.5 per cent on the Northern Border bank facility (2008 – 4.1 per cent).

The long-term debt of joint ventures is non-recourse to TransCanada, except that TransCanada has provided certain pro-rata guarantees related to the capital lease obligations of Bruce Power. The security provided with respect to the debt of each joint venture is limited to the rights and assets of the joint venture and does not extend to the rights and assets of TransCanada, except to the extent of TransCanada's investment. Trans Québec & Maritimes Pipeline Inc.'s (TQM Pipeline) bonds are secured by a first interest in all TQM Pipeline real and immoveable property and rights, a floating charge on all residual property and assets, and a specific interest on bonds of TQM Finance Inc. and on rights under all licenses and permits relating to the TQM pipeline system and natural gas transportation agreements.

Subject to meeting certain requirements, the Bruce Power capital lease agreements provide for a series of renewals commencing January 1, 2019. The first renewal is for a period of one year and each of 12 renewals thereafter is for a period of two years.

The Company's proportionate share of principal repayments for the next five years resulting from maturities and sinking fund obligations of the non-recourse joint venture debt is approximately as follows: 2010 – $199 million; 2011 – $21 million; 2012 – $120 million; 2013 – $7 million; and 2014 – $44 million.

The Company's proportionate share of principal payments for the next five years resulting from the capital lease obligations of Bruce Power is approximately as follows: 2010 – $13 million; 2011 – $15 million; 2012 – $18 million; 2013 – $20 million; and 2014 – $23 million.

In September 2009, TQM issued $75 million of bonds maturing in September 2014 and bearing interest at 4.05 per cent.

In August 2009, Northern Border issued US$100 million of Senior Unsecured Notes maturing in August 2016 and bearing interest at 6.24 per cent.

In May 2009, Iroquois issued US$140 million Senior Unsecured Notes maturing in May 2019 and bearing interest at 6.63 per cent.

In September 2008, Bruce A entered into a $193 million unsecured term loan maturing December 2031 and bearing interest at 7.1 per cent.

Sensitivity

A one per cent change in interest rates would have the following effect on net income assuming all other variables were to remain constant:

(millions of dollars)	Increase	Decrease
Effect on interest expense of variable interest rate debt	1	(1)

Interest Expense of Joint Ventures

Year ended December 31 (millions of dollars)	**2009**	2008	2007
Interest on long-term debt	**51**	45	50
Interest on capital lease obligations	**17**	18	18
Short-term interest and other financial charges	**6**	7	4
Capitalized interest	**(11)**	–	–
Deferrals and amortization	**1**	2	3
	64	72	75

The Company's proportionate share of the interest payments by joint ventures was $41 million in 2009 (2008 – $50 million; 2007 – $45 million) net of interest capitalized on construction projects.

The Company's proportionate share of interest payments from the capital lease obligations of Bruce Power was $17 million in 2009 (2008 and 2007 – $18 million).

NOTE 12 JUNIOR SUBORDINATED NOTES

Outstanding loan amount (millions of dollars)	Maturity Date	**2009** Outstanding December 31	**2009** Effective Interest Rate	2008 Outstanding December 31	2008 Effective Interest Rate
TRANSCANADA PIPELINES LIMITED					
U.S. dollars (2009 and 2008 – US$1,000)	2017	**1,036**	**6.5%**	1,213	6.5%

Junior Subordinated Notes of US$1.0 billion mature in 2067 and bear interest at 6.35 per cent per year until May 15, 2017, when interest will convert to a floating rate that is reset quarterly to the three-month London Interbank Offered Rate plus 221 basis points. The Company has the option to defer payment of interest for periods of up to ten years without giving rise to a default and without permitting acceleration of payment under the terms of the Junior Subordinated Notes. However, the Company would be prohibited from paying dividends during any such deferral period. The Junior Subordinated Notes are subordinated in right of payment to existing and future senior indebtedness and are effectively subordinated to all indebtedness and other obligations of TCPL. The Junior Subordinated Notes are callable at the Company's option at any time on or after May 15, 2017, at 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption. The Junior Subordinated Notes are callable earlier, in whole or in part, upon the occurrence of certain events and at the Company's option at an amount equal to the greater of 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption and an amount determined by a specified formula in accordance with the terms of the Junior Subordinated Notes.

NOTE 13 DEFERRED AMOUNTS

December 31 (millions of dollars)	**2009**	2008
Fair value of derivative contracts *(Note 18)*	**272**	694
Employee benefit plans *(Note 22)*	**235**	219
Asset retirement obligations *(Note 21)*	**110**	114
Other	**126**	141
	743	1,168

NOTE 14 RATE REGULATED BUSINESSES

TransCanada's rate regulated businesses currently include Canadian and U.S. natural gas pipelines and regulated U.S. natural gas storage. Regulatory assets and liabilities represent future revenues that are expected to be recovered from or refunded to customers based on decisions and approvals by the applicable regulatory authorities. In addition to GAAP financial reporting, TransCanada's regulated pipelines file financial reports using accounting regulations required by their respective regulators.

Canadian Regulated Operations

Canadian natural gas transmission services are supplied under natural gas transportation tariffs that provide for cost recovery, including return of and return on capital as approved by the applicable regulatory authorities.

Rates charged by TransCanada's Canadian regulated pipelines are set typically through a process that involves filing an application with the regulators for a change in rates. Regulated rates are underpinned by the total annual revenue requirement, which comprises a specified annual return on capital, including debt and equity, and all necessary operating expenses, taxes and depreciation.

TransCanada's Canadian regulated pipelines have generally been subject to a cost-of-service model wherein forecasted costs, including a return on capital, determine the revenues for the upcoming year. To the extent that actual costs and revenues are more or less than the forecasted costs and revenues, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in rates at that time. Costs for which the regulator does not allow the difference between actual and forecast to be deferred are included in the determination of net income in the year they are incurred.

The Canadian Mainline, Alberta System, Foothills and TQM pipelines are regulated by the NEB under the *National Energy Board Act* (Canada). Following an application by TransCanada to the NEB requesting a change in regulatory jurisdiction for the Alberta System, the NEB determined that the Alberta System is within federal jurisdiction and subject to NEB regulation effective April 29, 2009. Prior to April 2009, the Alberta

System was regulated by the AUC primarily under the provisions of the *Gas Utilities Act* (Alberta) and the *Pipeline Act* (Alberta). The NEB regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for the Company's Canadian regulated natural gas transmission systems.

In October 2009, the NEB issued a decision that its RH-2-94 Decision, which had established a rate of return on common equity (ROE) formula that formed the basis of determining tolls for pipelines under NEB jurisdiction since 1995, would not continue to be in effect. A company's cost of capital will now be determined by negotiations between pipeline companies and their shippers or by the NEB if a pipeline company files a cost of capital application. This decision impacts TransCanada's NEB regulated pipelines, however, the Canadian Mainline will continue to base its return on the RH-2-94 NEB ROE formula for the years 2010 and 2011 in accordance with the terms of the current Canadian Mainline tolls settlement. In November 2009, certain industry stakeholders appealed the October 2009 NEB decision with the Federal Court of Appeal and named the NEB as the sole respondent. TransCanada was granted respondent status in the matter and filed its submission opposing the leave application in February 2010.

Canadian Mainline
The Canadian Mainline currently operates under a five-year tolls settlement, which is effective January 1, 2007, to December 31, 2011. Canadian Mainline's cost of capital for establishing tolls under the settlement reflects ROE as determined by the NEB's ROE formula, on a deemed common equity ratio of 40 per cent. The allowed ROE in 2009 for the Canadian Mainline was 8.57 per cent (2008 – 8.71 per cent). The balance of the capital structure is comprised of short- and long-term debt.

The settlement also establishes the Canadian Mainline's fixed operating, maintenance and administrative (OM&A) costs for each year of the five years. Any variance between actual OM&A costs and those agreed to in the settlement have accrued fully to TransCanada from 2007 to 2009. Variances in OM&A costs will be shared equally between TransCanada and its customers in 2010 and 2011. All other cost elements of the revenue requirement are treated on a flow-through basis. There are also performance-based incentive arrangements that provide mutual benefits to both TransCanada and its customers.

Alberta System
In 2008 and 2009, the Alberta System operated under a two-year revenue requirement settlement approved by the AUC in 2008 and the NEB in 2009. As part of the settlement, fixed costs were established for ROE, income taxes and certain OM&A costs. Any variances between actual costs and those agreed to in the settlement accrue to TransCanada, subject to ROE and income tax adjustment mechanisms. All other costs are treated on a flow-through basis.

Foothills
The ROE for Foothills, which is based on the NEB-allowed ROE formula, was 8.57 per cent in 2009 (2008 – 8.71 per cent) on a deemed equity component of 36 per cent. A component of OM&A costs are fixed, subject to the terms of the BC System/Foothills Integration Settlement, with variances between actual and the fixed amounts shared with customers.

TQM
In June 2009, the NEB approved TQM's final tolls for 2007 and 2008, consisting of a 6.4 per cent after-tax weighted average cost of capital as authorized by the NEB in its RH-1-2008 Decision released in March 2009. This decision equates to a 9.85 per cent return on 40 per cent deemed common equity in 2007 and a 9.75 per cent return on 40 per cent deemed common equity in 2008. The decision granted TQM an aggregate return on capital and did not specify capital structure. Prior to this decision, TQM was subject to the NEB ROE formula on deemed common equity of 30 per cent. TQM's 2009 tolls remain in effect on an interim basis pending resolution of its cost of capital.

U.S. Regulated Operations
TransCanada's U.S. natural gas pipelines are 'natural gas companies' operating under the provisions of the *Natural Gas Act of 1938,* the *Natural Gas Policy Act of 1978* and the *Energy Policy Act of 2005*, and are subject to the jurisdiction of the FERC. The *Natural Gas Act of 1938* grants the FERC authority over the construction and operation of pipelines and related facilities. The FERC also has authority to regulate rates for natural gas transportation in interstate commerce.

ANR
ANR's operations are regulated primarily by the FERC. ANR's natural gas storage and transportation services regulated by the FERC also operate under approved tariff rates. ANR Pipeline Company's rates were established pursuant to a settlement approved by a FERC order issued in 1998. These tariffs include maximum and minimum rate levels for services and permit ANR to discount or negotiate rates on a non-discriminatory basis. ANR Storage Company's rates were established pursuant to a settlement approved by the FERC in 1990. None of ANR's FERC-regulated operations are currently required to file for new rates at any time in the future, nor are any of the operations prohibited from filing a case for new rates.

GTN
GTN is regulated by the FERC and operates in accordance with FERC-approved tariffs that establish maximum and minimum rates for various services. GTN is permitted to discount or negotiate these rates on a non-discriminatory basis. In November 2007, GTN and its customers

reached a rate case settlement that was approved by the FERC in January 2008. The settlement had an effective date of January 1, 2007, and established the rates currently in effect. Under the settlement, a five-year moratorium was established, during which GTN and the settling parties are prohibited from taking certain actions under the *Natural Gas Act of 1938*, including any rate adjustment filings. The settlement requires GTN to file a rate case within seven years of the effective date.

Great Lakes

In November 2009, the FERC initiated an investigation to determine whether Great Lakes' rates are just and reasonable. In response, Great Lakes filed a cost and revenue study with the FERC on February 4, 2010. A hearing is scheduled to commence on August 2, 2010, and an Initial Decision is required in November 2010. The impact of the investigation on Great Lakes' rates and revenues is unknown at this time.

Portland

In April 2008, Portland filed a general rate case with the FERC proposing a rate increase of approximately six per cent as well as other changes to its tariff. In May 2009, Portland reached a settlement with its customers on certain short-term issues in its rate case. The partial settlement has since been filed with the FERC and a final decision approving this partial settlement is expected in 2010. The remaining issues were litigated and Portland received the Initial Decision from the Administrative Law Judge in December 2009. Participants in the rate case now have an opportunity to respond to the Initial Decision. The FERC is expected to issue its final decision on the litigated portion of the rate case in fourth quarter 2010.

Northern Border

Northern Border and its customers reached a settlement in September 2006 that was approved by the FERC in November 2006. The settlement established maximum long-term mileage-based rates and charges for transportation on Northern Border's system. It provided for seasonal rates, which vary on a monthly basis, for short-term transportation services. It also included a three year moratorium on filing rate cases and on participants filing challenges to rates, and required Northern Border to file a general rate case within six years. Northern Border is required to provide services under negotiated and discounted rates on a non-discriminatory basis.

Regulatory Assets and Liabilities

Year ended December 31 (millions of dollars)	**2009**	2008	Remaining Recovery/ Settlement Period
			(years)
Regulatory Assets			
Future income taxes[1][2]	**1,305**	n/a	n/a
Operating and debt-service regulatory assets[3]	**221**	–	1
Unrealized losses on derivatives[4]	**99**	67	1 - 4
Foreign exchange on long-term debt principal[5]	**30**	32	20
Future income tax on AFUDC[6]	**23**	26	n/a
Unamortized issue costs on Preferred Securities[7]	**17**	18	17
Phase II preliminary expenditures[2][8]	**14**	16	6
Transitional other benefit obligations[2][9]	**13**	15	7
Unamortized post-retirement benefits[10]	**6**	11	2
Other	**17**	16	n/a
	1,745	201	
Less: Current portion included in Other Current Assets	**221**	–	
	1,524	201	
Regulatory Liabilities			
Foreign exchange on long-term debt[11]	**218**	70	1 - 20
Foreign exchange gain on redemption of Preferred Securities[7]	**68**	101	2
Post-retirement benefits other than pension[12]	**59**	58	n/a
Operating and debt-service regulatory liabilities[3]	**31**	234	1
Negative salvage[13]	**37**	39	n/a
Unamortized gains on derivatives[4]	**–**	24	n/a
Fuel tracker[14]	**–**	23	1
Other	**3**	2	n/a
	416	551	
Less: Current portion included in Accounts Payable	**31**	234	
	385	317	

(1) Effective January 1, 2009, CICA Handbook Section 3465 "Income Taxes" was amended to require the recognition of future income tax assets and liabilities for rate-regulated operations. The Company chose to adopt accounting policies consistent with FASB's ASC Topic 980 "Regulated Operations". As a result, TransCanada is required to recognize future income tax assets and liabilities, instead of using the taxes payable method. An offsetting adjustment is recorded to regulatory assets and liabilities. As a result of adopting this accounting change, additional future income tax liabilities and a regulatory asset in the amount of $1,305 million were recorded at December 31, 2009 in each of Future Income Taxes and Regulatory Assets, respectively. There was no effect on Net Income as a result of this change.

(2) These regulatory assets are either underpinned by non-cash transactions or are recovered without an allowance for return as approved by the regulator. Accordingly, these regulatory assets are not included in rate base and do not yield a return on investment during the recovery period.

(3) Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances approved by the regulatory authority for inclusion in determining tolls for the following calendar year. Pre-tax operating results would have been $424 million lower in 2009 (2008 – $316 million higher) if these amounts had not been recorded as regulatory assets and liabilities.

(4) Unrealized gains and losses on derivatives represent the net position of fair value gains and losses on cross-currency and interest-rate swaps, and forward foreign currency contracts, which act as economic hedges. The cross-currency swaps pertain to foreign debt instruments associated with the Canadian Mainline, Alberta System and Foothills. Pre-tax operating results would have been $56 million lower in 2009 (2008 – $63 million higher) if these amounts had not been recorded as regulatory assets and liabilities.

(5) The foreign exchange on long-term debt principal amount in the Alberta System, as approved by the AUC in 2008 and the NEB in 2009, is designed to facilitate the recovery or refund of foreign exchange gains and losses over the life of the foreign currency debt issues. Realized gains and losses and estimated net future losses on foreign currency debt are amortized over the remaining years of the longest outstanding U.S. debt issue. The annual amortization amount is included in the determination of tolls for the year. Pre-tax operating results would have been $2 million higher in 2009 and 2008 if these amounts had not been recorded as regulatory assets.

(6) Rate-regulated accounting allows the capitalization of both equity and interest components of AFUDC. The capitalized AFUDC is depreciated as part of the total depreciable plant after the utility assets are placed in service. Equity AFUDC is not subject to income taxes, therefore, a future income tax provision is recorded with an offset to a corresponding regulatory asset.

(7) In July 2007, the Company redeemed the US$460 million 8.25 per cent Preferred Securities that underpinned the Canadian Mainline's investment base. Upon redemption of the securities, a foreign exchange gain was realized that will flow through, net of income tax, to Canadian Mainline's customers over the five years of the current tolls settlement. In addition, the issue costs on the Preferred Securities will be amortized over 20 years beginning January 1, 2007. At December 31, 2009, the unamortized amount of $68 million (2008 – $101 million) is net of income taxes of $6 million (2008 – $10 million). If these amounts had not been recorded as a regulatory liability, pre-tax operating results would have been $37 million lower in 2009 (2008 – $53 million lower).

(8) Phase II preliminary expenditures are costs incurred by Foothills prior to 1981 related to development of Canadian facilities to deliver Alaskan gas. These costs have been approved by the regulator for collection through straight-line amortization over the period November 2002 to December 2015. Pre-tax operating results would have been $2 million higher in 2009 and 2008 if these amounts had not been recorded as regulatory assets.

(9) The regulatory asset with respect to the annual transitional other benefit obligations is being amortized over 17 years to December 2016, at which time the full transitional obligation will have been recovered through tolls. Pre-tax operating results would have been $2 million higher in 2009 (2008 – $1 million higher) if these amounts had not been recorded as regulatory assets.

(10) An amount is recovered in ANR's rates for post-retirement benefits other than pensions (PBOP). A curtailment and special termination benefits charge related to PBOP for a closed group of retirees was recorded as a regulatory asset and is being amortized through 2011. Pre-tax operating results would have been $5 million higher in 2009 (2008 – $3 million higher) if these amounts had not been recorded as regulatory assets.

(11) Foreign exchange on long-term debt of the Canadian Mainline, Alberta System and Foothills represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historical foreign exchange rate. Foreign exchange gains and losses realized when foreign debt matures or is redeemed early are expected to be recovered or refunded through the determination of future tolls. In the absence of rate-regulated accounting, GAAP would have required the inclusion of these unrealized gains or losses on the Balance Sheet or Income Statement depending on whether the foreign debt is designated as a hedge of the Company's net investment in foreign assets.

(12) An amount is recovered in ANR's rates for PBOP. This regulatory liability represents the difference between the amount collected in rates and the amount of PBOP expense. The PBOP expense recorded in 2009 was $1 million (2008 – nil).

(13) Negative salvage is recovered in rates for certain regulated facilities. These amounts are recorded as a regulatory liability. Costs associated with the abandonment of these facilities will reduce this regulatory liability when they are paid.

(14) ANR's tariff stipulates a fuel tracker mechanism to track over- or under-collections of fuel used and natural gas lost and unaccounted for (collectively, fuel). The fuel tracker represents the difference between the value of 'in-kind' natural gas retained from shippers and the actual amount of natural gas used for fuel by ANR. Any over- or under-collections are returned to or collected from shippers through a prospective annual adjustment to fuel retention rates. A regulatory asset or liability is established for the difference between ANR's actual fuel use and amounts collected through its fuel rates. Pre-tax operating results are not affected by the fuel tracker mechanism.

NOTE 15 NON-CONTROLLING INTERESTS

The Company's non-controlling interests included in the Consolidated Balance Sheet were as follows:

December 31 (millions of dollars)	**2009**	2008
Non-controlling interest in PipeLines LP[(1)]	**705**	721
Preferred shares of subsidiary	**389**	389
Non-controlling interest in Portland	**80**	84
	1,174	1,194

The Company's non-controlling interests included in the Consolidated Income Statement were as follows:

Year ended December 31 (millions of dollars)	**2009**	2008	2007
Non-controlling interest in PipeLines LP[(1)]	**66**	62	65
Preferred share dividends of subsidiary	**22**	22	22
Non-controlling interest in Portland	**8**	46	10
	96	130	97

(1) Effective November 18, 2009, the non-controlling interests in PipeLines LP was 61.8 per cent. From July 1, 2009 to November 17, 2009, the non-controlling interests in PipeLines LP was 57.4 per cent. From February 22, 2007 to June 30, 2009, the non-controlling interests in PipeLines LP was 67.9 per cent.

The non-controlling interests in PipeLines LP and Portland as at December 31, 2009 represented the 61.8 per cent and 38.3 per cent interest, respectively, not owned by TransCanada (2008 and 2007 – 67.9 per cent and 38.3 per cent, respectively).

TransCanada received fees of $2 million from PipeLines LP in 2009 (2008 and 2007 – $2 million) and $8 million from Portland in 2009 (2008 and 2007 – $7 million) for services it provided.

Preferred Shares of Subsidiary

December 31	Number of Shares	Dividend Rate per Share	Redemption Price per Share	**2009**	2008
	(thousands)			(millions of dollars)	(millions of dollars)
Cumulative First Preferred Shares of Subsidiary					
Series U	4,000	$2.80	$50.00	**195**	195
Series Y	4,000	$2.80	$50.00	**194**	194
				389	389

The authorized number of preferred shares of TCPL issuable in each series is unlimited. All of the cumulative first preferred shares of TCPL are without par value.

On or after October 15, 2013, TCPL may redeem the Series U shares at $50 per share, and on or after March 5, 2014, TCPL may redeem the Series Y shares at $50 per share.

Cash Dividends

Cash dividends of $22 million or $2.80 per share were paid on the Series U and Series Y preferred shares in each of 2009, 2008 and 2007.

NOTE 16 COMMON SHARES

	Number of Shares	Amount
	(thousands)	(millions of dollars)
Outstanding at January 1, 2007	488,975	4,794
Issuance of common shares[1]	45,390	1,683
Dividend reinvestment and share purchase plan	4,147	157
Exercise of options	1,253	28
Outstanding at December 31, 2007	539,765	6,662
Issuance of common shares[1]	69,805	2,363
Dividend reinvestment and share purchase plan	5,976	218
Exercise of options	925	21
Outstanding at December 31, 2008	616,471	9,264
Issuance of common shares[1]	**58,420**	**1,792**
Dividend reinvestment and share purchase plan	**8,220**	**254**
Exercise of options	**1,248**	**28**
Outstanding at December 31, 2009	**684,359**	**11,338**

(1) Net of underwriting commissions and future income taxes.

Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares without par value.

In September 2009, TransCanada filed a base shelf prospectus qualifying for issuance $3.0 billion of common shares, first or second preferred shares and subscription receipts in Canada and the U.S. until October 2011. This base shelf prospectus replaced the base shelf prospectus filed in July 2008. The Company had $2.45 billion available under this prospectus at December 31, 2009.

In July 2008, TransCanada filed a base shelf prospectus to allow for the offering of up to $3.0 billion of common shares, preferred shares and subscription receipts in Canada and the U.S. until August 2010. This base shelf prospectus replaced the base shelf prospectus filed in January 2007. The July 2008 prospectus was depleted by the common share issues discussed below.

- In June 2009, TransCanada completed a public offering of common shares at a purchase price of $31.50 per share. The issue of 58.4 million common shares, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.8 billion.
- In fourth quarter 2008, TransCanada completed a public offering of common shares at a purchase price of $33.00 per share. The issue of 35.1 million common shares, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.2 billion.

In January 2007, TransCanada filed a base shelf prospectus to allow for the offering of up to $3.0 billion of common shares, preferred shares and subscription receipts in Canada and the U.S. until February 2009. The January 2007 prospectus was depleted by the common share issues discussed below.

- In May 2008, TransCanada completed a public offering of common shares at a purchase price of $36.50 per share. The issue of 34.7 million common shares, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.3 billion.
- In first quarter 2007, the Company completed a public offering of common shares at a purchase price of $38.00 per share. The issue of 45.4 million common shares, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.7 billion.

Net Income per Share

Net Income per Share is calculated by dividing Net Income Applicable to Common Shares by the weighted average number of common shares. During the year, the weighted average number of common shares of 651.8 million and 652.8 million (2008 – 569.6 million and 571.5 million; 2007 – 529.9 million and 532.5 million) were used to calculate basic and diluted earnings per share, respectively. The increase in the weighted average number of shares for the diluted earnings per share calculation is due to the options exercisable under TransCanada's Stock Option Plan.

Stock Options

	Number of Options	Weighted Average Exercise Prices	Options Exercisable
	(thousands)		(thousands)
Outstanding at January 1, 2007	8,799	$25.37	5,888
Granted	1,083	$38.10	
Exercised	(1,253)	$22.77	
Forfeited	(20)	$35.08	
Outstanding at December 31, 2007	8,609	$27.32	6,118
Granted	872	$39.75	
Exercised	(925)	$22.26	
Forfeited	(55)	$35.23	
Outstanding at December 31, 2008	8,501	$29.10	6,461
Granted	**1,191**	**$31.96**	
Exercised	**(1,248)**	**$21.22**	
Forfeited	**(170)**	**$35.58**	
Outstanding at December 31, 2009	**8,274**	**$30.56**	**6,212**

Stock options outstanding at December 31, 2009, were as follows:

	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
	(thousands)		(years)	(thousands)		(years)
$10.03 to $18.01	680	$16.22	1.1	680	$16.22	1.1
$20.59 to $21.43	900	$21.43	2.2	900	$21.43	2.2
$22.33 to $26.85	1,136	$25.89	1.1	1,136	$25.89	1.1
$30.09 to $31.93	952	$30.28	3.4	846	$30.09	2.2
$31.97 to $33.08	1,681	$32.37	5.5	615	$33.06	3.5
$35.23	1,026	$35.23	3.2	1,026	$35.23	3.2
$38.10	948	$38.10	4.1	642	$38.10	4.1
$38.14 to $39.75	951	$39.58	5.1	367	$39.43	5.0
	8,274	$30.56	2.9	6,212	$29.07	2.8

An additional 3.2 million common shares were reserved for future issuance under TransCanada's Stock Option Plan at December 31, 2009. The weighted average fair value of options granted to purchase common shares under the Company's Stock Option Plan was determined to be $4.78 (2008 – $3.97; 2007 – $4.22). The Company used the Black-Scholes model for determining the fair value of options granted applying the following weighted average assumptions for 2009: four years of expected life (2008 and 2007 – four years); 1.7 per cent interest rate (2008 – 3.5 per cent; 2007 – 4.1 per cent); 29 per cent volatility (2008 – 16 per cent; 2007 – 15 per cent); and 5.2 per cent dividend yield (2008 – 4.0 per cent; 2007 – 3.6 per cent). The amount expensed for stock options, with a corresponding increase in contributed surplus, was $4 million in 2009 (2008 and 2007 – $4 million).

The total intrinsic value of options exercised in 2009 was $15 million (2008 – $15 million; 2007 – $21 million). As at December 31, 2009, the aggregate intrinsic value for the total currently exercisable options was $47 million and the total intrinsic value of outstanding options was $52 million. In 2009, the 1.2 million (2008 – 1.4 million; 2007 – 1.4 million) shares that vested had a fair value of $43 million (2008 – $45 million; 2007 – $57 million).

Shareholder Rights Plan
TransCanada's Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Under certain circumstances, each common share is entitled to one right that entitles certain holders to purchase two common shares of the Company for the price of one.

Cash Dividends
Cash dividends of $722 million or $1.50 per common share were paid in 2009 (2008 – $577 million or $1.42 per common share; 2007 – $546 million or $1.34 per common share).

Dividend Reinvestment and Share Purchase Plan
TransCanada's Board of Directors authorized the issuance of common shares from treasury at a discount to participants in the Company's Dividend Reinvestment and Share Purchase Plan (DRP). Under the DRP, eligible holders of common and preferred shares of TransCanada and preferred shares of TCPL may reinvest their dividends and make optional cash payments to obtain TransCanada common shares. The DRP shares are provided to the participants at a discount to the average market price in the five days prior to dividend payment. The discount was set at two per cent commencing with the dividend payable in April 2007 and was increased to three per cent with the dividend payable in January 2009. Prior to the April 2007 dividend, TransCanada purchased shares on the open market and provided them to DRP participants at cost. The Company reserves the right to alter the discount or return to purchasing shares on the open market at any time. In 2009, dividends of $254 million were paid (2008 – $218 million; 2007 – $157 million) through the issuance of 8.2 million (2008 – 6.0 million; 2007 – 4.1 million) common shares from treasury in accordance with the DRP.

NOTE 17 PREFERRED SHARES

December 31	Number of Shares	Dividend Rate per Share	Redemption Price per Share	**2009**
	(thousands)			(millions of dollars)[1]
Cumulative First Preferred Shares				
Series 1	22,000	$1.15	$25.00	**539**

[1] Net of underwriting commissions and future income taxes.

In September 2009, TransCanada completed a public offering of 22 million cumulative redeemable first preferred shares under a prospectus supplement to the September 2009 base shelf prospectus for gross proceeds of $550 million. The holders of the preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.15 per share, payable quarterly, yielding 4.6 per cent per annum, for the initial five year period ending December 31, 2014. The dividend rate will reset on December 31, 2014 and every five years thereafter to a yield per annum equal to the sum of the then five year Government of Canada bond yield plus 1.92 per cent. The preferred shares are redeemable by TransCanada on or after December 31, 2014 at a price of $25 per share plus all accrued and unpaid dividends. The preferred shareholders are eligible to participate in the Company's DRP. The first dividend was paid December 31, 2009.

The preferred shareholders will have the right to convert their shares into Series 2 cumulative redeemable first preferred shares on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.92 per cent.

Cash Dividends
Cash dividends of $6 million or $0.2875 per preferred share were paid in 2009.

NOTE 18 RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TransCanada has exposure to market risk, counterparty credit risk and liquidity risk. TransCanada engages in risk management activities with the objective being to protect earnings, cash flow and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure TransCanada's risks and related exposures are in line with the Company's business objectives and risk tolerance. Risks are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by risk management and internal audit personnel. The Board of Directors' Audit Committee oversees how management monitors compliance with risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework. Internal audit personnel assist the Audit Committee in its oversight role by performing regular and ad-hoc reviews of risk management controls and procedures, the results of which are reported to the Audit Committee.

Market Risk

The Company constructs and invests in large infrastructure projects, purchases and sells energy commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. These activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which affect the Company's earnings and the value of the financial instruments it holds.

The Company uses derivatives as part of its overall risk management strategy to manage the exposure to market risk that results from these activities. Derivative contracts used to manage market risk generally consist of the following:

- Forwards and futures contracts – contractual agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future. TransCanada enters into foreign exchange and commodity forwards and futures to mitigate the impact of volatility in foreign exchange rates and commodity prices.
- Swaps – contractual agreements between two parties to exchange streams of payments over time according to specified terms. The Company enters into interest rate, cross-currency and commodity swaps to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.
- Options – contractual agreements to convey the right, but not the obligation, of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. The Company enters into option agreements to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.

Commodity Price Risk

The Company is exposed to commodity price movements as part of its normal business operations, particularly in relation to the prices of electricity, natural gas and oil products. A number of strategies are used to mitigate these exposures, including the following:

- Subject to its overall risk management strategy, the Company commits a significant portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to mitigate price risk in its asset portfolio.
- The Company purchases a portion of the natural gas and oil products required for its power plants or enters into contracts that base the sales price of electricity on the cost of natural gas, effectively locking in a margin. A significant portion of the electricity needed to fulfill the Company's power sales commitments is fulfilled through power generation or purchased through contracts, thereby reducing the Company's exposure to fluctuating commodity prices.
- The Company enters into offsetting or back-to-back positions using derivative financial instruments to manage price risk exposure in power and natural gas commodities created by certain fixed and variable pricing arrangements for different pricing indices and delivery points.

The Company assesses its commodity contracts and derivative instruments used to manage commodity risk to determine the appropriate accounting treatment. Contracts, with the exception of leases, have been assessed to determine whether they or certain aspects of them meet the definition of a derivative. Certain commodity purchase and sale contracts are derivatives but are not within the scope of the CICA Handbook Section 3855 "Financial Instruments – Recognition and Measurement", as they were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's expected purchase, sale or usage requirements. Certain other contracts are not within the scope of Section 3855 as they are considered to meet other exemptions.

TransCanada manages its exposure to seasonal natural gas price spreads in its natural gas storage business by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. TransCanada simultaneously enters into a forward purchase of natural gas for injection into storage and an offsetting forward sale of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to natural gas price movements. Fair value adjustments recorded each period on proprietary natural gas inventory in storage and these forward contracts may not be representative of the amounts that will be realized on settlement.

Natural Gas Inventory Price Risk
At December 31, 2009, the fair value of proprietary natural gas inventory in storage, as measured using a weighted average of forward prices for the following four months less selling costs, was $73 million (2008 – $76 million). The change in fair value of proprietary natural gas inventory in storage in 2009 resulted in a net pre-tax unrealized gain of $3 million (2008 – unrealized loss of $7 million; 2007 – nil), which was recorded as an increase to Revenues and Inventories. The net change in fair value of natural gas forward purchase and sales contracts in 2009 resulted in a net pre-tax unrealized loss of $2 million (2008 – unrealized gain of $7 million; 2007 unrealized gain of $10 million), which was recorded as a decrease in Revenues.

Foreign Exchange and Interest Rate Risk
Foreign exchange and interest rate risk is created by fluctuations in the fair value or cash flow of financial instruments due to changes in foreign exchange rates and market interest rates.

A portion of TransCanada's earnings from its Pipelines and Energy segments is generated in U.S. dollars and, as such, movement of the Canadian dollar relative to the U.S. dollar can affect TransCanada's earnings. This foreign exchange impact is offset by certain related debt and financing costs being denominated in U.S. dollars and by the Company's hedging activities. TransCanada has a greater exposure to U.S. currency fluctuations than in prior years due to growth in its U.S. operations, partially offset by increased levels of U.S. dollar-denominated debt.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to its debt and other U.S. dollar-denominated transactions, and to manage the interest rate exposures of the Canadian Mainline, Alberta System and Foothills operations. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms. These gains and losses are deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers in accordance with the terms of the shipping agreements.

TransCanada has floating interest rate debt, which subjects it to interest rate cash flow risk. The Company uses a combination of interest rate swaps and options to manage its exposure to this risk.

On a consolidated basis, the impact of changes in the U.S. dollar on U.S. Pipelines and Energy earnings is largely offset by the impact on U.S. dollar interest expense. The resultant net exposure is managed using derivatives, effectively reducing the Company's exposure to changes in foreign exchange rates.

Net Investment in Self-Sustaining Foreign Operations
The Company hedges its net investment in self-sustaining foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, forward foreign exchange contracts and foreign exchange options. At December 31, 2009, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $7.9 billion (US$7.6 billion) (2008 – $7.2 billion (US$5.9 billion)) and a fair value of $9.8 billion (US$9.3 billion) (2008 – $5.9 billion (US$4.8 billion)). At December 31, 2009, $96 million was included in Intangibles and Other Assets (2008 – $254 million in Deferred Amounts) for the fair value of the forwards, swaps and options used to hedge the Company's net U.S. dollar investment in foreign operations.

The fair values and notional or principal amounts for the derivatives designated as a net investment hedge were as follows:

Asset/(Liability) *December 31 (millions of dollars)*	**2009** **Fair Value(1)**	**2009** **Notional or Principal Amount**	2008 Fair Value(1)	2008 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2010 to 2014)	**86**	**U.S. 1,850**	(218)	U.S. 1,650
U.S. dollar forward foreign exchange contracts (maturing 2010)	**9**	**U.S. 765**	(42)	U.S. 2,152
U.S. dollar options (maturing 2010)	**1**	**U.S. 100**	6	U.S. 300
	96	**U.S. 2,715**	(254)	U.S. 4,102

(1) Fair values equal carrying values.

VaR Analysis
TransCanada uses a Value-at-Risk (VaR) methodology to estimate the potential impact resulting from its exposure to market risk on its open liquid positions. VaR estimates the potential change in pre-tax earnings over a given holding period for a specified confidence level. The VaR number calculated and used by TransCanada reflects a 95 per cent probability that the daily change resulting from normal market fluctuations in its open liquid positions will not exceed the reported VaR. The VaR methodology is a statistically-calculated, probability-based approach that takes into consideration market volatilities as well as risk diversification by recognizing offsetting positions and correlations among products and markets. Risks are measured across all products and markets, and risk measures are aggregated to arrive at a single VaR number.

There is currently no uniform industry methodology for estimating VaR. The use of VaR has limitations because it is based on historical correlations and volatilities in commodity prices, interest rates and foreign exchange rates, and assumes that future price movements will follow a statistical distribution. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR.

TransCanada's estimation of VaR includes wholly owned subsidiaries and incorporates relevant risks associated with each market or business unit. The calculation does not include the Pipelines segment as the rate-regulated nature of the pipeline business reduces the impact of market risks. TransCanada's Board of Directors has established a VaR limit, which is monitored on an ongoing basis as part of the Company's risk management policy. TransCanada's consolidated VaR was $12 million at December 31, 2009 (2008 – $23 million). The decline from December 31, 2008 was primarily due to decreased prices and lower open positions in the U.S. power portfolio.

Counterparty Credit Risk
Counterparty credit risk represents the financial loss the Company would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of its contracts with the Company.

Counterparty credit risk is managed through established credit management techniques, including conducting financial and other assessments to establish and monitor a counterparty's creditworthiness, setting exposure limits, monitoring exposures against these limits, using master netting arrangements and obtaining financial assurances where warranted. In general, financial assurances include guarantees, letters of credit and cash. The Company monitors and manages its concentration of counterparty credit risk on an ongoing basis. The Company believes these measures minimize its counterparty credit risk but there is no certainty that they will protect it against all material losses.

TransCanada's maximum counterparty credit exposure with respect to financial instruments at the balance sheet date consisted primarily of non-derivative financial assets such as accounts receivable, loans and notes receivable, as well as the fair value of derivative assets. Within these balances, the Company does not have significant concentrations of counterparty credit risk with any individual counterparties and the majority of counterparty credit exposure is with counterparties who are investment grade. At December 31, 2009, there were no significant amounts past due or impaired.

TransCanada has significant credit and performance exposures to financial institutions as they provide committed credit lines and cash deposit facilities, critical liquidity in the foreign exchange derivative, interest rate derivative and energy wholesale markets, and letters of credit to mitigate TransCanada's exposure to non-creditworthy counterparties.

As a level of uncertainty continues to exist in the global financial markets, TransCanada continues to closely monitor and reassess the creditworthiness of its counterparties. This has resulted in TransCanada reducing or mitigating its exposure to certain counterparties where it was deemed warranted and permitted under contractual terms. As part of its ongoing operations, TransCanada must balance its market and counterparty credit risks when making business decisions.

Certain subsidiaries of Calpine Corporation (Calpine) filed for bankruptcy protection in both Canada and the U.S. in 2005. Gas Transmission Northwest Corporation (GTNC) and Portland reached agreements with Calpine for allowed unsecured claims in the Calpine bankruptcy. In February 2008, GTNC and Portland received initial distributions of 9.4 million common shares and 6.1 million common shares, respectively, of Calpine, which represented approximately 85 per cent of their agreed-upon claims. In 2008, these shares were sold into the open market and resulted in total pre-tax gains of $279 million. Claims by NGTL and Foothills Pipe Lines (South B.C.) Ltd. for $32 million and $44 million, respectively, were received in cash in January 2008 and were passed on to shippers on these systems in 2008 and 2009.

Liquidity Risk
Liquidity risk is the risk that TransCanada will not be able to meet its financial obligations when due. The Company's approach to managing liquidity risk is to ensure that, under both normal and stressed conditions, it always has sufficient cash and credit facilities to meet its obligations when due without incurring unacceptable losses or damage to the Company's reputation.

Management continuously forecasts cash flows for a period of 12 months to identify financing requirements. These requirements are then managed through a combination of committed and demand credit facilities and access to capital markets, as discussed under the heading Capital Management below.

At December 31, 2009, the Company had committed revolving bank lines of US$1.0 billion, $2.0 billion, US$1.0 billion and US$300 million maturing November 2010, December 2012, December 2012 and February 2013, respectively. At December 31, 2009, the US$300 million facility was fully drawn and no draws were made on any of the other facilities. The Company has maintained continuous access to the Canadian commercial paper market on competitive terms.

The Company has access to capital markets under the following prospectuses:

- In December 2009, TCPL filed a US$4.0 billion debt base shelf prospectus qualifying for the issuance of up to US$4.0 billion of debt securities in the U.S. At December 31, 2009, no amounts were issued under the base shelf prospectus.
- In September 2009, TransCanada filed a $3.0 billion base shelf prospectus qualifying for the issuance of up to $3.0 billion of equity instruments in Canada and the U.S. until October 2011. At December 31, 2009 the Company had $2.45 billion available under the prospectus.
- In April 2009, TCPL filed a $2.0 billion Medium-Term Notes base shelf prospectus in Canada. At December 31, 2009, no amounts were issued under this base shelf prospectus.

Capital Management

The primary objective of capital management is to ensure TransCanada has strong credit ratings to support its businesses and maximize shareholder value. In 2009, the overall objective and policy for managing capital remained unchanged from the prior year.

TransCanada manages its capital structure in a manner consistent with the risk characteristics of the underlying assets. The Company's management considers its capital structure to consist of net debt, Non-Controlling Interests and Shareholders' Equity. Net debt is comprised of Notes Payable, Long-Term Debt and Junior Subordinated Notes less Cash and Cash Equivalents. Net debt only includes obligations that the Company controls and manages. Consequently, it does not include Cash and Cash Equivalents, Notes Payable and Long-Term Debt of TransCanada's joint ventures.

The capital structure was as follows:

December 31 (millions of dollars)	**2009**	2008
Notes payable	**1,678**	1,685
Long-term debt	**16,664**	16,154
Junior subordinated notes	**1,036**	1,213
Cash and cash equivalents	**(896)**	(1,117)
Net debt	**18,482**	17,935
Non-controlling interests	**1,174**	1,194
Shareholders' equity	**15,759**	12,898
Total equity	**16,933**	14,092
Total Capital	**35,415**	32,027

Fair Values

Certain financial instruments included in Cash and Cash Equivalents, Accounts Receivable, Intangibles and Other Assets, Notes Payable, Accounts Payable, Accrued Interest and Deferred Amounts have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity. The fair value of foreign exchange and interest rate derivatives has been calculated using year-end market rates. The fair value of power, natural gas and oil products derivatives has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques are used. Credit risk has been taken into consideration when calculating the fair value of derivatives.

The fair value of the Company's Long-Term Debt was estimated based on quoted market prices for the same or similar debt instruments and, when such information was not available, was estimated by discounting future payments of interest and principal at estimated interest rates that were made available to the Company.

Non-Derivative Financial Instruments Summary

The carrying and fair values of non-derivative financial instruments were as follows:

	2009		2008	
December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial Assets[(1)]				
Cash and cash equivalents	**997**	**997**	1,308	1,308
Accounts receivable and intangibles and other assets[(2)(3)]	**1,432**	**1,483**	1,427	1,427
Available-for-sale assets[(2)]	**23**	**23**	27	27
	2,452	**2,503**	2,762	2,762
Financial Liabilities[(1)(3)]				
Notes payable	**1,687**	**1,687**	1,702	1,702
Accounts payable and deferred amounts[(4)]	**1,538**	**1,538**	1,372	1,372
Accrued interest	**377**	**377**	359	359
Long-term debt	**16,664**	**19,377**	16,154	15,337
Junior subordinated notes	**1,036**	**976**	1,213	815
Long-term debt of joint ventures	**965**	**1,025**	1,076	1,052
	22,267	**24,980**	21,876	20,637

(1) Consolidated Net Income in 2009 included $6 million (2008 – $15 million) for fair value adjustments related to interest rate swap agreements on US$250 million (2008 – US$200 million and $50 million) of long-term debt. There were no other unrealized gains or losses from fair value adjustments to these financial instruments.

(2) At December 31, 2009, the Consolidated Balance Sheet included financial assets of $966 million (2008 – $1,280 million) in Accounts Receivable and $489 million (2008 – $174 million) in Intangibles and Other Assets.

(3) Recorded at amortized cost except for certain Long-Term Debt and Notes Receivable which are adjusted to fair value.

(4) At December 31, 2009, the Consolidated Balance Sheet included financial liabilities of $1,513 million (2008 – $1,350 million) in Accounts Payable and $25 million (2008 – $22 million) in Deferred Amounts.

The following tables detail the remaining contractual maturities for TransCanada's non-derivative financial liabilities, including both the principal and interest cash flows at December 31, 2009:

Contractual Repayments of Financial Liabilities[(1)]

		Payments Due by Period			
(millions of dollars)	Total	2010	2011 and 2012	2013 and 2014	2015 and Thereafter
Notes payable	1,687	1,687	–	–	–
Long-term debt and junior subordinated notes	17,700	478	2,099	1,879	13,244
Long-term debt of joint ventures	965	212	174	94	485
	20,352	2,377	2,273	1,973	13,729

(1) The anticipated timing of settlement of derivative contracts is presented in the Derivatives Financial Instrument Summary in this note.

Interest Payments on Financial Liabilities

		Payments Due by Period			
(millions of dollars)	Total	2010	2011 and 2012	2013 and 2014	2015 and Thereafter
Long-term debt and junior subordinated notes	17,123	1,186	2,260	2,093	11,584
Long-term debt of joint ventures	305	46	73	65	121
	17,428	1,232	2,333	2,158	11,705

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2009 is as follows:

	2009				
December 31 (all amounts in millions unless otherwise indicated)	**Power**	**Natural Gas**	**Oil Products**	**Foreign Exchange**	**Interest**
Derivative Financial Instruments Held for Trading[1]					
Fair Values[2]					
Assets	**$150**	**$107**	**$5**	**$–**	**$25**
Liabilities	**$(98)**	**$(112)**	**$(5)**	**$(66)**	**$(68)**
Notional Values					
Volumes[3]					
Purchases	**15,275**	**238**	**180**	**–**	**–**
Sales	**13,185**	**194**	**180**	**–**	**–**
Canadian dollars	**–**	**–**	**–**	**–**	**574**
U.S. dollars	**–**	**–**	**–**	**U.S. 444**	**U.S. 1,325**
Cross-currency	**–**	**–**	**–**	**227/U.S. 157**	**–**
Net unrealized gains/(losses) in the year	**$3**	**$(5)**	**$1**	**$3**	**$27**
Net realized gains/(losses) in the year	**$70**	**$(76)**	**$–**	**$36**	**(22)**
Maturity dates	**2010-2015**	**2010-2014**	**2010**	**2010-2012**	**2010-2018**
Derivative Financial Instruments in Hedging Relationships[4][5]					
Fair Values[2]					
Assets	**$175**	**$2**	**$–**	**$–**	**$15**
Liabilities	**$(148)**	**$(22)**	**$–**	**$(43)**	**$(50)**
Notional Values					
Volumes[3]					
Purchases	**13,641**	**33**	**–**	**–**	**–**
Sales	**14,311**	**–**	**–**	**–**	**–**
U.S. dollars	**–**	**–**	**–**	**U.S. 120**	**U.S. 1,825**
Cross-currency	**–**	**–**	**–**	**136/U.S. 100**	**–**
Net realized gains/(losses) in the year	**$156**	**$(29)**	**$–**	**$–**	**$(37)**
Maturity dates	**2010-2015**	**2010-2014**	**–**	**2010-2014**	**2010-2020**

(1) All derivative financial instruments in the held-for-trading classification have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

(2) Fair values equal carrying values.

(3) Volumes for power, natural gas and oil products derivatives are in GWh, billion cubic feet (Bcf) and thousands of barrels, respectively.

(4) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $4 million and a notional amount of US$150 million. Net realized gains on fair value hedges for December 31, 2009 were $4 million and were included in Interest Expense. In 2009, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(5) In 2009, Net Income included losses of $5 million for the changes in fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2009, there were no gains or losses included in Net Income for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

The anticipated timing of settlement of the derivative contracts assumes constant commodity prices, interest rates and foreign exchange rates from December 31, 2009. Settlements will vary based on the actual value of these factors at the date of settlement. The anticipated timing of settlement of these contracts is as follows:

Year ended December 31 (millions of dollars)	Total	2010	2011 and 2012	2013 and 2014	2015 and Thereafter
Derivative financial instruments held for trading					
Assets	287	201	73	11	2
Liabilities	(349)	(233)	(85)	(27)	(4)
Derivative financial instruments in hedging relationships					
Assets	288	142	106	35	5
Liabilities	(263)	(106)	(89)	(66)	(2)
	(37)	4	5	(47)	1

Derivative Financial Instruments Summary
Information for the Company's derivative financial instruments for 2008 is as follows:

	2008				
December 31 (all amounts in millions unless otherwise indicated)	Power	Natural Gas	Oil Products	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading					
Fair Values(1)					
Assets	$132	$144	$10	$41	$57
Liabilities	$(82)	$(150)	$(10)	$(55)	$(117)
Notional Values					
Volumes(2)					
Purchases	4,035	172	410	–	–
Sales	5,491	162	252	–	–
Canadian dollars	–	–	–	–	1,016
U.S. dollars	–	–	–	U.S. 479	U.S. 1,575
Japanese yen (in billions)	–	–	–	JPY 4.3	–
Cross-currency	–	–	–	227/U.S. 157	–
Net unrealized gains/(losses) in the year	$24	$(23)	$1	$(9)	$(61)
Net realized gains/(losses) in the year	$23	$(2)	$1	$6	$13
Maturity dates	2009-2014	2009-2011	2009	2009-2012	2009-2018
Derivative Financial Instruments in Hedging Relationships(3)(4)					
Fair Values(1)					
Assets	$115	$–	$–	$2	$8
Liabilities	$(160)	$(18)	$–	$(24)	$(122)
Notional Values					
Volumes(2)					
Purchases	8,926	9	–	–	–
Sales	13,113	–	–	–	–
Canadian dollars	–	–	–	–	50
U.S. dollars	–	–	–	U.S. 15	U.S. 1,475
Cross-currency	–	–	–	136/U.S. 100	–
Net realized (losses)/gains in the year	$(56)	$15	$–	$–	$(10)
Maturity dates	2009-2014	2009-2011	–	2009-2013	2009-2019

(1) Fair values equal carrying values.

(2) Volumes for power, natural gas and oil products derivatives are in GWh, Bcf and thousands of barrels, respectively.

(3) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $8 million and notional amounts of $50 million and US$50 million. Net realized gains on fair value hedges at December 31, 2008 were $1 million. In 2008, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(4) In 2008, Net Income included losses of $6 million for changes in fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2008, there were no gains or losses included in Net Income for discontinued cash flow hedges.

Balance Sheet Presentation of Derivative Financial Instruments

The fair value of the derivative financial instruments in the Company's Balance Sheet was as follows:

December 31 (millions of dollars)	**2009**	2008
Current		
Other current assets	**315**	318
Accounts payable	**(340)**	(298)
Long-term		
Intangibles and other assets	**260**	191
Deferred amounts	**(272)**	(694)

Derivative Financial Instruments of Joint Ventures

Included in the Balance Sheet Presentation of Derivative Financial Instruments summary are amounts related to power derivatives used by one of the Company's joint ventures to manage commodity price risk. The Company's proportionate share of the fair value of these power sales derivatives was $105 million at December 31, 2009 (2008 – $75 million). These contracts mature from 2010 to 2015. The Company's proportionate share of the notional sales volumes of power associated with this exposure was 6,312 gigawatt hours (GWh) at December 31, 2009 (2008 – 7,600 GWh). The Company's proportionate share of the notional purchased volumes of power associated with this exposure was 2,747 GWh at December 31, 2009 (2008 – 47 GWh).

Fair Value Hierarchy

The Company's financial assets and liabilities recorded at fair value have been categorized into three categories based upon a fair value hierarchy. Fair value of assets and liabilities included in Level I is determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level II include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. This category includes fair value determined using valuation techniques, such as option pricing models and extrapolation using observable inputs. Level III valuations are based on inputs that are not readily observable and are significant to the overall fair value measurement. Long-dated commodity transactions in certain markets and the fair value of guarantees are included in this category. Long-dated commodity prices are derived with a third party modelling tool that uses market fundamentals to derive long-term prices. The fair value of guarantees is estimated by discounting the cash flows that would be incurred if letters of credit were used in place of the guarantees.

Assets and liabilities measured at fair value as of December 31, 2009, including both current and non-current portions, are categorized as follows. There were no transfers between Level I and Level II in 2009.

(millions of dollars, pre-tax)	Quoted Prices in Active Markets (Level I)	Significant Other Observable Inputs (Level II)	Significant Unobservable Inputs (Level III)	Total
Natural Gas Inventory	–	73	–	73
Derivative Financial Instruments:				
Assets	65	509	14	588
Liabilities	(109)	(500)	(16)	(625)
Non-Derivative Financial Instruments: Available-for-sale assets	23	–	–	23
Guarantee Liabilities[1]	–	–	(9)	(9)
	(21)	82	(11)	50

(1) The fair value of guarantees is included in Deferred Amounts as at December 31, 2009.

The following table presents the net change in assets and liabilities measured at fair value and included in the Level III fair value category:

(millions of dollars, pre-tax)	Derivatives[1]	Guarantees[2]	Total
Balance at December 31, 2008	–	(9)	(9)
New contracts[3]	**(14)**	**–**	**(14)**
Transfers into Level III[4]	**12**	**–**	**12**
Total realized and unrealized gains/(losses) included in Deferred Amounts	**–**	**(7)**	**(7)**
Other	**–**	**7**	**7**
Balance at December 31, 2009	**(2)**	**(9)**	**(11)**

(1) The fair value of derivative assets and liabilities is presented on a net basis.

(2) The fair value of guarantees is recognized in Deferred Amounts. No amounts were recognized in earnings for the periods presented.

(3) The total amount of net gains included in earnings attributable to derivatives that were entered into during the period and still held at the reporting date is nil for the year ended December 31, 2009.

(4) These contracts were previously included in Level II but were reclassified to Level III due to reduced liquidity in the market to which they relate.

A 10 per cent increase or 10 per cent decrease in commodity prices, with all other variables held constant, would cause an $18 million decrease or an $18 million increase, respectively, in the fair value of derivative financial instruments outstanding as at December 31, 2009.

A 100 basis points increase or 100 basis points decrease in the letter of credit rate, with all other variables held constant, would cause a $6 million increase or a $6 million decrease, respectively, in the fair value of guarantee liabilities outstanding as at December 31, 2009. Similarly, the effect of a 100 basis points increase or 100 basis points decrease in the discount rate on the fair value of guarantee liabilities outstanding as at December 31, 2009 would cause a $2 million decrease in the liability or a $2 million increase in the liability, respectively.

NOTE 19 INCOME TAXES

Provision for Income Taxes

Year ended December 31 (millions of dollars)	**2009**	2008	2007
Current			
Canada	**(70)**	383	367
Foreign	**100**	143	65
	30	526	432
Future			
Canada	**339**	(1)	12
Foreign	**18**	77	46
	357	76	58
	387	602	490

Geographic Components of Income

Year ended December 31 (millions of dollars)	**2009**	2008	2007
Canada	**1,095**	1,234	1,228
Foreign	**768**	938	582
Income before Income Taxes and Non-Controlling Interests	**1,863**	2,172	1,810

Reconciliation of Income Tax Expense

Year ended December 31 (millions of dollars)	**2009**	2008	2007
Income before income taxes and non-controlling interests	**1,863**	2,172	1,810
Federal and provincial statutory tax rate	**29.0%**	29.5%	32.1%
Expected income tax expense	**540**	641	581
Income tax differential related to regulated operations	**39**	44	69
Lower effective foreign tax rates	**(63)**	(5)	(39)
Tax rate and legislative changes	**(30)**	–	(72)
Income from equity investments and non-controlling interests	**(37)**	(45)	(34)
Change in valuation allowance	**–**	(9)	–
Other[1]	**(62)**	(24)	(15)
Actual Income Tax Expense	**387**	602	490

[1] Includes net income tax benefits of $22 million recorded in 2009 (2008 – $5 million; 2007 – $13 million) on the resolution of certain income tax matters with taxation authorities as well as changes in estimates.

Future Income Tax Assets and Liabilities

December 31 (millions of dollars)	**2009**	2008
Deferred amounts	**42**	119
Other post-employment benefits	**72**	69
Unrealized losses on derivatives	**56**	62
Unrealized foreign exchange losses on long-term debt	**–**	77
Non-capital loss carryforwards	**148**	24
Other	**127**	137
	445	488
Less: valuation allowance[1]	**–**	77
Future income tax assets, net of valuation allowance	**445**	411
Difference in accounting and tax bases of plant, equipment and PPAs	**2,642**	1,464
Taxes on future revenue requirement	**338**	–
Investments in subsidiaries and partnerships	**17**	28
Pension benefits	**75**	55
Unrealized foreign exchange gains on long-term debt	**96**	14
Unrealized gains on derivatives	**32**	19
Deferred credits	**57**	–
Other	**44**	54
Future income tax liabilities	**3,301**	1,634
Net Future Income Tax Liabilities	**2,856**	1,223

[1] A valuation allowance was recorded in 2008 as there was no virtual certainty that the Company would realize the tax benefit related to the unrealized foreign exchange losses on long-term debt in the future.

Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. Future income tax liabilities would have increased by approximately $101 million at December 31, 2009 (2008 – $102 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $83 million, net of refunds received were made in 2009 (2008 – $491 million; 2007 – $442 million).

NOTE 20 NOTES PAYABLE

	2009		2008	
	Outstanding December 31	**Weighted Average Interest Rate per Annum at December 31**	Outstanding December 31	Weighted Average Interest Rate per Annum at December 31
	(millions of dollars)		(millions of dollars)	
Canadian dollars	**327**	**0.3%**	1,250	1.8%
U.S. dollars (2009 – US$1,299; 2008 – US$369)	**1,360**	**0.4%**	452	3.3%
	1,687		1,702	

Notes payable consists of commercial paper outstanding and draws on bridge and line-of-credit facilities.

At December 31, 2009, total committed revolving and demand credit facilities of $5.2 billion were available. When drawn, interest on the lines of credit is charged at prime rates of Canadian chartered and U.S. banks, and at other negotiated financial bases. These unsecured credit facilities included the following:

- A $2.0 billion committed, syndicated, revolving TCPL credit facility maturing December 2012. The facility was fully available at December 31, 2009. The cost to maintain the credit facility was $2 million in 2009 and 2008.
- A US$300 million committed, syndicated revolving facility, guaranteed by TransCanada, maturing February 2013. This facility is part of the US$1.0 billion TCPL USA credit facility discussed in Note 10. At December 31, 2009, this facility was fully drawn. The cost to maintain the credit facility was $1 million in 2009 and 2008.
- A US$1.0 billion committed, syndicated revolving TransCanada Keystone Pipeline, L.P. credit facility, guaranteed by TCPL, maturing November 2010 but extendible to November 2011 at the option of the borrower. The facility was fully available at December 31, 2009. The cost to maintain the credit facility was $2 million in 2009 (2008 – nil).
- A US$1.0 billion committed, syndicated revolving TCPL USA credit facility established in fourth quarter 2009, maturing December 2012 with a one year term extension at the option of the borrower. The facility is guaranteed by TransCanada and was fully available at December 31, 2009.
- Demand lines totalling $805 million, which support the issuance of letters of credit and provide additional liquidity. The Company had used approximately $467 million of these demand lines for letters of credit at December 31, 2009.

In June 2008, TransCanada executed an agreement with a syndicate of banks for a US$1.5 billion committed, unsecured, one year bridge loan facility, which was extendible at the option of the Company for an additional six month term. In August 2008, the Company used US$255 million from this facility to fund a portion of the Ravenswood acquisition and cancelled the remainder of the commitment. In February 2009, the US$255 million was repaid and the facility was cancelled.

NOTE 21 ASSET RETIREMENT OBLIGATIONS

The estimated undiscounted cash flows required to settle the asset retirement obligations with respect to the regulated and non-regulated operations in the Pipelines segment were $64 million at December 31, 2009 (2008 – $69 million), calculated using an annual inflation rate ranging from one per cent to four per cent. The estimated fair value of these liabilities was $24 million at December 31, 2009 (2008 – $31 million) after discounting the estimated cash flows at rates ranging from 5.4 per cent to 11.0 per cent. At December 31, 2009, the expected timing of payment for settlement of the obligations ranged from 2010 to 2029.

The estimated undiscounted cash flows required to settle the asset retirement obligations with respect to the Energy segment were $424 million at December 31, 2009 (2008 – $427 million), calculated using an annual inflation rate ranging from two per cent to three per cent. The estimated fair value of this liability was $87 million at December 31, 2009 (2008 – $85 million), after discounting the estimated cash flows at rates ranging from 5.4 per cent to eight per cent. At December 31, 2009, the expected timing of payment for settlement of the obligations ranged from 2017 to 2041.

Reconciliation of Asset Retirement Obligations(1)

(millions of dollars)	Pipelines	Energy	Total
Balance at January 1, 2007	9	36	45
New obligations and revisions in estimated cash flows	14	25	39
Accretion expense	2	2	4
Balance at December 31, 2007	25	63	88
New obligations and revisions in estimated cash flows	4	18	22
Accretion expense	2	4	6
Balance at December 31, 2008	31	85	116
New obligations and revisions in estimated cash flows	**(9)**	**(4)**	**(13)**
Accretion expense	**2**	**6**	**8**
Balance at December 31, 2009	**24**	**87**	**111**

(1) At December 31, 2009, Asset Retirement Obligations totalling $110 million (2008 – $114 million) and $1 million (2008 – $2 million) were included in Deferred Amounts and Accounts Payable, respectively.

NOTE 22 EMPLOYEE FUTURE BENEFITS

The Company sponsors DB Plans that cover the significant majority of employees. Pension benefits provided under the DB Plans are based on years of service and highest average earnings over three consecutive years of employment, and increase annually in the Canadian pension plan by a portion of the increase in the Consumer Price Index (CPI). Past service costs are amortized over the expected average remaining service life of employees, which is approximately eight years.

The Company also provides its employees with a Savings Plan in Canada, 401(k) Plans (DC Plans) in the U.S. and post-employment benefits other than pensions, including termination benefits and defined life insurance and medical benefits beyond those provided by government-sponsored plans. Past service costs are amortized over the expected average remaining life expectancy of former employees, which was approximately 13 years at December 31, 2009. Contributions to the Savings Plan and DC Plans are expensed as incurred. The Company expensed $21 million in 2009 (2008 – $21 million; 2007 – $8 million) for the Savings Plan and DC Plans.

Total cash payments for employee future benefits, consisting of cash contributed by the Company to the DB Plans and other benefit plans, was $168 million in 2009 (2008 – $90 million; 2007 – $61 million), including $21 million in 2009 (2008 – $21 million; 2007 – $8 million) related to the Savings Plan and DC Plans.

The Company measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2010, and the next required valuation will be as at January 1, 2011.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2009**	2008	**2009**	2008
Change in Benefit Obligation				
Benefit obligation – beginning of year	**1,332**	1,462	**144**	155
Current service cost	**45**	52	**2**	2
Interest cost	**89**	80	**9**	8
Employee contributions	**4**	3	**1**	1
Benefits paid	**(70)**	(68)	**(8)**	(8)
Actuarial loss/(gain)	**107**	(261)	**10**	(21)
Foreign exchange rate changes	**(31)**	35	**(8)**	10
Plan amendment	**–**	–	**–**	(11)
Acquisition	**–**	29	**–**	8
Benefit obligation – end of year	**1,476**	1,332	**150**	144
Change in Plan Assets				
Plan assets at fair value – beginning of year	**1,193**	1,358	**26**	30
Actual return on plan assets	**206**	(222)	**5**	(10)
Employer contributions	**140**	62	**7**	7
Employee contributions	**4**	3	**1**	1
Benefits paid	**(70)**	(68)	**(8)**	(8)
Foreign exchange rate changes	**(26)**	32	**(4)**	6
Acquisition	**–**	28	**–**	–
Plan assets at fair value – end of year	**1,447**	1,193	**27**	26
Funded status – plan deficit	**(29)**	(139)	**(123)**	(118)
Unamortized net actuarial loss	**329**	340	**37**	33
Unamortized past service costs	**21**	25	**(3)**	(1)
Accrued Benefit Asset/(Liability), Net of Valuation Allowance of Nil	**321**	226	**(89)**	(86)

The accrued benefit asset/(liability) net of valuation allowance of nil in the Company's Balance Sheet was as follows:

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2009**	2008	**2009**	2008
Intangibles and other assets	**323**	226	**–**	–
Deferred amounts	**(2)**	–	**(89)**	(86)
Total	**321**	226	**(89)**	(86)

Included in the above benefit obligation and fair value of plan assets at December 31 were the following amounts for plans that are not fully funded:

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2009**	2008	**2009**	2008
Benefit obligation	**(390)**	(1,317)	**(150)**	(144)
Plan assets at fair value	**358**	1,178	**27**	26
Funded Status – Plan Deficit	**(32)**	(139)	**(123)**	(118)

The Company's expected contributions in 2010 are approximately $115 million for the pension benefit plans and approximately $28 million for the other benefit plans, Savings Plan and DC plans.

The following are estimated future benefit payments, which reflect expected future service:

(millions of dollars)	Pension Benefits	Other Benefits
2010	77	8
2011	81	9
2012	84	9
2013	87	10
2014	91	10
2015 to 2019	520	55

The significant weighted average actuarial assumptions adopted in measuring the Company's benefit obligations at December 31 were as follows:

	Pension Benefit Plans		Other Benefit Plans	
	2009	2008	**2009**	2008
Discount rate	**6.00%**	6.65%	**6.00%**	6.50%
Rate of compensation increase	**3.20%**	3.65%		

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan cost for years ended December 31 were as follows:

	Pension Benefit Plans			Other Benefit Plans		
	2009	2008	2007	**2009**	2008	2007
Discount rate	**6.65%**	5.30%	5.05%	**6.50%**	5.50%	5.20%
Expected long-term rate of return on plan assets	**6.95%**	6.95%	6.90%	**7.75%**	7.75%	7.75%
Rate of compensation increase	**3.25%**	3.60%	3.50%			

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and estimating future levels and volatility of returns. Asset class benchmark returns, asset mix and anticipated benefit payments from plan assets are also considered in determining the overall expected rate of return. The discount rate is based on market interest rates of high quality bonds that match the timing and benefits expected to be paid under each plan.

A nine per cent annual rate of increase in the per capita cost of covered health care benefits was assumed for 2010 measurement purposes. The rate was assumed to decrease gradually to five per cent by 2019 and remain at this level thereafter. A one percentage point change in assumed health care cost trend rates would have the following effects:

(millions of dollars)	Increase	Decrease
Effect on total of service and interest cost components	1	(1)
Effect on post-employment benefit obligation	13	(12)

The Company's net benefit cost is as follows:

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31 (millions of dollars)	**2009**	2008	2007	**2009**	2008	2007
Current service cost	**45**	52	45	**2**	2	2
Interest cost	**89**	80	73	**9**	8	7
Actual return on plan assets	**(206)**	222	(33)	**(5)**	10	(2)
Actuarial loss/(gain)	**107**	(261)	(22)	**10**	(21)	8
Plan amendment	**–**	–	–	**–**	(11)	–
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**35**	93	63	**16**	(12)	15
Difference between expected and actual return on plan assets	**107**	(316)	(51)	**3**	(12)	(1)
Difference between actuarial loss/(gain) recognized and actual actuarial loss/(gain) on accrued benefit obligation	**(101)**	280	47	**(8)**	23	(7)
Difference between amortization of past service costs and actual plan amendments	**4**	4	4	**–**	11	–
Amortization of transitional obligation related to regulated business	**–**	–	–	**2**	2	2
Net Benefit Cost Recognized	**45**	61	63	**13**	12	9

The Company pension plans' weighted average asset allocations and target allocations by asset category were as follows:

December 31	Percentage of Plan Assets		Target Allocations
Asset Category	**2009**	2008	**2009**
Debt securities	**40%**	48%	**35% to 60%**
Equity securities	**60%**	52%	**40% to 65%**
	100%	100%	

Debt securities included the Company's debt of $4 million (0.3 per cent of total plan assets) and $3 million (0.3 per cent of total plan assets) at December 31, 2009 and 2008, respectively. Equity securities included the Company's common shares of $8 million (0.6 per cent of total plan assets) and $4 million (0.3 per cent of total plan assets) at December 31, 2009 and 2008, respectively.

The assets of the pension plans are managed on a going concern basis subject to legislative restrictions. The plans' investment policies are to maximize returns within an acceptable risk tolerance. Pension assets are invested in a diversified manner with consideration given to the demographics of the plans' participants.

Employee Future Benefits of Joint Ventures

Certain of the Company's joint ventures sponsor DB Plans as well as post-employment benefits other than pensions, including defined life insurance and medical benefits beyond those provided by government-sponsored plans. The obligations of these plans are non-recourse to TransCanada. The following amounts in this note, including those in the accompanying tables, represent TransCanada's proportionate share with respect to these plans.

Total cash payments for employee future benefits, consisting of cash contributed by the Company's joint ventures to DB Plans and other benefit plans was $54 million in 2009 (2008 – $42 million; 2007 – $34 million).

The Company's joint ventures measure the benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuations of the pension plans for funding purposes were as at January 1, 2010, and the next required valuations will be as at January 1, 2011.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2009**	2008	**2009**	2008
Change in Benefit Obligation				
Benefit obligation – beginning of year	**599**	789	**133**	165
Current service cost	**16**	27	**5**	8
Interest cost	**40**	42	**9**	9
Employee contributions	**6**	6	**–**	–
Benefits paid	**(33)**	(37)	**(4)**	(4)
Actuarial loss/(gain)	**68**	(229)	**27**	(45)
Foreign exchange rate changes	**(1)**	1	**–**	–
Benefit obligation – end of year	**695**	599	**170**	133
Change in Plan Assets				
Plan assets at fair value – beginning of year	**556**	626	**–**	–
Actual return on plan assets	**63**	(78)	**–**	–
Employer contributions	**50**	38	**4**	4
Employee contributions	**6**	6	**–**	–
Benefits paid	**(33)**	(37)	**(4)**	(4)
Foreign exchange rate changes	**(1)**	1	**–**	–
Plan assets at fair value – end of year	**641**	556	**–**	–
Funded status – plan deficit	**(54)**	(43)	**(170)**	(133)
Unamortized net actuarial loss/(gain)	**113**	51	**25**	(3)
Unamortized past service costs	**–**	–	**2**	3
Accrued Benefit Asset/(Liability), Net of Valuation Allowance of Nil	**59**	8	**(143)**	(133)

The accrued benefit asset/(liability), net of valuation allowance of nil in the Company's Balance Sheet was as follows:

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2009**	2008	**2009**	2008
Intangibles and other assets	**60**	8	**–**	–
Deferred amounts	**(1)**	–	**(143)**	(133)
	59	8	**(143)**	(133)

The following amounts were included at December 31 in the above benefit obligation and fair value of plan assets for plans that are not fully funded:

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2009**	2008	**2009**	2008
Benefit obligation	**(695)**	(594)	**(170)**	(133)
Plan assets at fair value	**641**	551	**–**	–
Funded Status – Plan Deficit	**(54)**	(43)	**(170)**	(133)

The expected total contributions of the Company's joint ventures in 2010 are approximately $57 million for the pension benefit plans and approximately $6 million for the other benefit plans.

The following are estimated future benefit payments, which reflect expected future service:

(millions of dollars)	Pension Benefits	Other Benefits
2010	40	5
2011	43	6
2012	47	6
2013	50	7
2014	53	8
2015 to 2019	315	48

The significant weighted average actuarial assumptions adopted in measuring the benefit obligations of the Company's joint ventures at December 31 were as follows:

	Pension Benefit Plans		Other Benefit Plans	
	2009	2008	**2009**	2008
Discount rate	**6.00%**	6.70%	**5.80%**	6.40%
Rate of compensation increase	**3.50%**	3.50%		

The significant weighted average actuarial assumptions adopted in measuring the net benefit plan costs of the Company's joint ventures for years ended December 31 were as follows:

	Pension Benefit Plans			Other Benefit Plans		
	2009	2008	2007	**2009**	2008	2007
Discount rate	**6.75%**	5.25%	5.00%	**6.40%**	5.15%	4.90%
Expected long-term rate of return on plan assets	**7.00%**	7.00%	7.00%			
Rate of compensation increase	**3.50%**	3.50%	3.50%			

A one percentage point change in assumed health care cost trend rates would have the following effects:

(millions of dollars)	Increase	Decrease
Effect on total of service and interest cost components	2	(2)
Effect on post-employment benefit obligation	21	(18)

The Company's proportionate share of net benefit cost of joint ventures is as follows:

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31 (millions of dollars)	**2009**	2008	2007	**2009**	2008	2007
Current service cost	**16**	27	28	**5**	8	10
Interest cost	**40**	42	40	**9**	9	8
Actual return on plan assets	**(63)**	78	1	**–**	–	–
Actuarial loss/(gain)	**68**	(229)	(34)	**27**	(45)	(16)
Plan amendment	**–**	–	–	**–**	–	(2)
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**61**	(82)	35	**41**	(28)	–
Difference between expected and actual return on plan assets	**25**	(122)	(44)	**–**	–	–
Difference between actuarial loss/(gain) recognized and actual actuarial loss/(gain) on accrued benefit obligation	**(67)**	239	44	**(28)**	48	20
Difference between amortization of past service costs and actual plan amendments	**–**	–	–	**–**	–	3
Net Benefit Cost Recognized Related to Joint Ventures	**19**	35	35	**13**	20	23

The weighted average asset allocations and target allocations by asset category in the pension plans of the Company's joint ventures were as follows:

December 31	Percentage of Plan Assets		Target Allocations
Asset Category	**2009**	2008	**2009**
Debt securities	**40%**	44%	**40%**
Equity securities	**60%**	56%	**60%**
	100%	100%	

Debt securities included the Company's debt of $1 million (0.1 per cent of total plan assets) and $1 million (0.2 per cent of total plan assets) at December 31, 2009 and 2008, respectively. Equity securities included the Company's common shares of $4 million (0.6 per cent of total plan assets) and $3 million (0.6 per cent of total plan assets) at December 31, 2009 and 2008, respectively.

The assets of the pension plans are managed on a going concern basis subject to legislative restrictions. The plans' investment policies are to maximize returns within an acceptable risk tolerance. Pension assets are invested in a diversified manner with consideration given to the demographics of the plans' participants.

NOTE 23 CHANGES IN OPERATING WORKING CAPITAL

Year ended December 31 (millions of dollars)	**2009**	2008	2007
Decrease/(increase) in accounts receivable	**314**	(197)	51
(Increase)/decrease in inventories	**(19)**	82	(6)
(Increase)/decrease in other current assets	**(249)**	(61)	33
(Decrease)/increase in accounts payable	**(154)**	213	(6)
Increase/(decrease) in accrued interest	**18**	98	(9)
(Increase)/Decrease in Operating Working Capital	**(90)**	135	63

NOTE 24 COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

Operating leases

Future annual payments, net of sub-lease receipts, under the Company's operating leases for various premises, services and equipment are approximately as follows:

Year ended December 31 (millions of dollars)	Minimum Lease Payments	Amounts Recoverable under Sub-leases	Net Payments
2010	86	(12)	74
2011	83	(9)	74
2012	81	(5)	76
2013	79	(4)	75
2014	76	(4)	72
2015 and thereafter	494	(3)	491
	899	(37)	862

The operating lease agreements for premises, services and equipment expire at various dates through 2052, with an option to renew certain lease agreements for periods of one year to ten years. Net rental expense on operating leases in 2009 was $91 million (2008 – $52 million; 2007 – $34 million).

TransCanada's commitments under the Alberta PPAs are considered to be operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Future payments under these PPAs have been excluded from the above table, as these payments are dependent upon plant availability, among other factors. TransCanada's share of power purchased under the PPAs in 2009 was $384 million (2008 – $398 million; 2007 – $391 million). The generating capacities and expiry dates of the PPAs are as follows:

	Megawatts	Expiry Date
Sundance A	560	December 31, 2017
Sundance B	353	December 31, 2020
Sheerness	756	December 31, 2020

TransCanada and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business.

Bruce Power

Bruce A has signed commitments with third-party suppliers related to refurbishing and restarting Units 1 and 2. TransCanada's share of these signed commitments, which extend over a two year period ending December 31, 2011, are as follows:

Year ended December 31 (millions of dollars)	
2010	256
2011	39
	295

Loan – Aboriginal Pipeline Group

In 2003, the Mackenzie Delta gas producers, the Aboriginal Pipeline Group (APG) and TransCanada reached an agreement governing TransCanada's role in the Mackenzie Gas Pipeline (MGP) project. The project would result in a natural gas pipeline being constructed from Inuvik, Northwest Territories, to the northern border of Alberta, where it would connect with the Alberta System. Under the agreement, TransCanada agreed to finance the APG for its one-third share of project pre-development costs. These costs, on a cumulative basis, are currently forecast to be between $150 million and $200 million. As at December 31, 2009, the Company had advanced $143 million to the APG.

TransCanada and the other co-venture companies involved in the MGP continue to pursue approval of the proposed project, focusing on obtaining regulatory approval and the Canadian government's support of an acceptable fiscal framework. The regulatory process reached a milestone in late December 2009 with the release of the Joint Review Panel's report on environmental and socio-economic factors relating to the project. That report has been submitted into the NEB review process for approval of the project, which is scheduled to conclude in April 2010 with final arguments. A decision is currently expected by fourth quarter 2010.

In the event the co-venture group is unable to reach an agreement with the government on an acceptable fiscal framework, the parties will need to determine the appropriate next steps for the project. For TransCanada, this may result in a reassessment of the carrying amount of the APG advances.

Other Commitments

At December 31, 2009, TransCanada was committed to Pipelines capital expenditures totalling approximately $2.0 billion related primarily to construction costs of Keystone, expansion of the Alberta System and construction costs for Guadalajara and Bison.

At December 31, 2009, the Company was committed to Energy capital expenditures totalling approximately $1.3 billion related primarily to its share of the construction and development costs of Oakville, Bruce Power, Coolidge, Halton Hills and the second phase of Kibby Wind.

Contingencies

TransCanada is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2009, the Company accrued approximately $67 million related to operating facilities. The accrued amount represents the Company's estimate of the amount it expects to expend to remediate the sites. However, additional liabilities may be incurred as assessments occur and remediation efforts continue.

TransCanada and its subsidiaries are subject to various legal proceedings and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

Guarantees

TransCanada, Cameco Corporation and BPC Generation Infrastructure Trust (BPC) have severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, a lease agreement and contractor services. The guarantees have terms ranging from 2018 to perpetuity. In addition, TransCanada and BPC have severally guaranteed one-half of certain contingent financial obligations related to an agreement with the Ontario Power Authority to refurbish and restart Bruce A power generation units. The guarantees were provided as part of the reorganization of Bruce Power in 2005 and have terms ending in 2018 and 2019. In its 2009 decision to renew the operating licenses of Bruce Power, the Canadian Nuclear Safety Commission (CNSC) ordered that it was no longer necessary for the major partners of Bruce Power, including TransCanada, to provide financial assurances to Bruce Power to support its license obligations. After adjusting for the CNSC guarantees, TransCanada's share of the potential exposure under these Bruce A and Bruce B guarantees was estimated at December 31, 2009 at $741 million. The fair value of these Bruce Power guarantees is estimated to be $82 million. The Company's exposure under certain of these guarantees is unlimited.

In addition to the guarantees for Bruce Power, the Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities related primarily to redelivery of natural gas, PPA payments and the payment of liabilities. TransCanada's share of the potential exposure under these guarantees was estimated at December 31, 2009 to range from $351 million to a maximum of $632 million. The fair value of these guarantees is estimated to be $9 million which has been included in Deferred Amounts. The Company's exposure under certain of these guarantees is unlimited. For certain of these entities, any payments made by TransCanada under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

NOTE 25 SUBSEQUENT EVENTS

Subsequent events have been assessed up to February 22, 2010, which is the date the financial statements were available for issuance.