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The Management's Discussion and Analysis (MD&A) dated February 25, 2008 should be read in conjunction with the audited Consolidated Financial Statements of TransCanada Corporation (TransCanada or the Company) and the notes thereto for the year ended December 31, 2007. This MD&A covers TransCanada's financial position and operations as at and for the year ended December 31, 2007. Amounts are stated in Canadian dollars unless otherwise indicated. Abbreviations and acronyms used in this MD&A are identified in the Glossary of Terms in the Company's 2007 Annual Report.

TRANSCANADA OVERVIEW

With more than 50 years experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure, including natural gas pipelines, power generation, natural gas storage facilities and projects related to oil pipelines and liquefied natural gas (LNG) facilities. TransCanada's network of wholly owned natural gas pipelines extends more than 59,000 kilometres (km), tapping into virtually all major gas supply basins in North America. TransCanada is one of the continent's largest providers of natural gas storage and related services with approximately 355 billion cubic feet (Bcf) of natural gas storage capacity. A growing independent power producer, TransCanada owns, or has interests in, approximately 7,700 megawatts (MW) of power generation in Canada and the United States (U.S.).

In addition to having total assets in excess of $30 billion, TransCanada plans to invest approximately $10 billion in a number of energy infrastructure projects in North America, with the expectation that a majority of these projects will be completed by 2010. Over the longer-term, TransCanada has a significant portfolio of large-scale infrastructure opportunities that will continue to be pursued and developed.

North America's demand for natural gas, oil and electricity is expected to continue to grow. By 2020, it is expected that demand for natural gas will grow by 15 billion cubic feet per day (Bcf/d), demand for crude oil will increase by 3 million barrels per day (Bbl/d) and demand for power will grow by 155 gigawatts.

Demand for natural gas in North America is expected to increase due primarily to a growing demand for electricity. The long lead times required to complete new coal and nuclear projects could slow the development and completion of new coal or nuclear generation facilities over the next five to ten years. As a result, North America is expected to continue to rely on natural gas-fired generation to satisfy a large portion of its growing electricity needs. North America has entered a period when it will no longer be able to rely solely on traditional sources of natural gas supply to meet its growing needs. This outlook for traditional sources of natural gas means that northern gas and offshore LNG could be required to fill the shortfall between supply and demand for natural gas. TransCanada is well positioned to capture related opportunities in natural gas transmission, LNG infrastructure and power generation.

TransCanada is also expanding into the crude oil transmission business with the development of a 590,000 Bbl/d crude oil pipeline from Hardisty, Alberta to refineries in U.S. midwest markets. TransCanada has partnered with ConocoPhillips, a global, integrated oil and gas producer and refiner to construct the Keystone oil pipeline to transport crude oil from Alberta to refineries in Illinois and Oklahoma. The partnership provides TransCanada with a platform for developing future crude oil pipeline opportunities. Significant oilsands development in Alberta is providing opportunities for new crude oil transmission infrastructure.

TransCanada has the financial strength and flexibility to build new infrastructure to support increased energy demand, to respond to shifting energy supply-demand dynamics and to replace aging North American infrastructure.

Pipelines Assets

TransCanada's natural gas pipeline assets link gas supplies from basins in Western Canada, the 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 and offshore LNG imports, to growing markets. With increasing production from the oilsands in Alberta and growing demand for secure, reliable sources of energy, TransCanada has identified opportunities to develop oil pipeline capacity.

TransCanada's Alberta System gathered 68 per cent of the natural gas produced in Western Canada or 16 per cent of total North American production in 2007. TransCanada exports 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, the GTN System and Foothills Pipe Lines Ltd. (Foothills).

American Natural Resources Company and ANR Storage Company (collectively, ANR) were acquired in February 2007. ANR Pipeline Company (ANR Pipeline), a subsidiary of American Natural Resources Company, transports natural gas from producing fields located primarily in Oklahoma, Texas, Louisiana and the Gulf of Mexico to markets located primarily in Wisconsin, Michigan, Illinois, Ohio and Indiana. ANR Pipeline 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 access to a variety of end-user markets in the midwestern and northeastern U.S.

As a result of the ANR acquisition, TransCanada owns and operates approximately 235 Bcf of regulated natural gas storage capacity in Michigan, making it one of North America's largest gas storage operators.

TransCanada also exports 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 Transmission Limited Partnership (Great Lakes), Iroquois Gas Transmission System, L.P. (Iroquois), Portland Natural Gas Transmission System (Portland), Trans Québec & Maritimes System (TQM), Northern Border Pipeline Company (Northern Border) and Tuscarora Gas Transmission Company (Tuscarora). Certain of these pipeline systems are held through the Company's 32.1 per cent interest in TC PipeLines, LP (PipeLines LP).

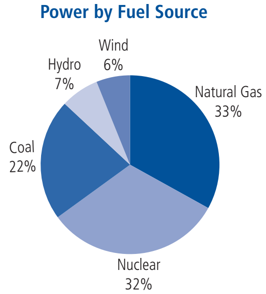
The Company also transports natural gas through the wholly owned TransCanada Pipeline Ventures Limited Partnership (Ventures LP) pipeline in Alberta, North Baja pipeline in the U.S. and Tamazunchale pipeline in Mexico, as well as the partially owned TransGas de Occidente S.A. (TransGas) pipeline in Columbia and Gasoducto del Pacifico S.A. (Gas Pacifico) pipeline in Argentina.

In addition, the Company has a 50 per cent ownership interest in each of TransCanada Keystone Pipeline Limited Partnership (Keystone Canada) and TransCanada Keystone Pipeline LP (Keystone U.S.), (collectively Keystone). Currently beginning its construction phase, Keystone will transport crude oil from Hardisty, Alberta, to U.S. Midwest markets at Wood River and Patoka in Illinois, and to Cushing, Oklahoma.

Energy Assets

TransCanada has built a substantial energy business over the past decade and has achieved a significant presence in power generation in selected regions of Canada and the U.S. TransCanada owns, or has rights or interests in, approximately 7,700 MW of power generation in Canada and the U.S. These assets are primarily low-cost, base-load generation and/or are assets backed by secure, long-term power sales agreements. More recently, TransCanada has also developed a significant non-regulated natural gas storage business in Alberta.

Power by Fuel Source



The Company's power assets are concentrated in two main regions: Western Power in Alberta and Eastern Power in the Eastern Canada and New England markets. TransCanada's portfolio of power supply is shown in the accompanying chart.

All of TransCanada's non-regulated natural gas storage assets are located in Alberta. TransCanada owns or has rights to 120 Bcf or approximately one-third of the natural gas storage capacity in the province.

Opportunities and developments in the Company's Pipelines and Energy businesses are discussed further in the "Pipelines" and "Energy" sections of this MD&A.

TRANSCANADA'S STRATEGY

TransCanada's vision is to be the leading energy infrastructure company in North America, with a strong focus on pipelines and power generation opportunities located in regions where the Company enjoys significant competitive advantages. Since 2000, TransCanada's key strategies have evolved with the Company's progression and the changing business environment. Today, TransCanada's corporate strategy consists of the following six components:

- Maximize the long-term value of the Company's natural gas transmission business;
- Grow the North American pipeline and related infrastructure business;
- Maximize the long-term value of existing power generation and power marketing and related businesses;
- Grow North American power and energy businesses;

- Drive for operational excellence; and
- Maximize TransCanada's competitive strength and enduring value.

Maximize the long-term value of the Company's natural gas transmission business
TransCanada continues to place a priority on maximizing the long-term value of its natural gas transmission business. There is a strong focus on connecting supply with markets through expansions, extensions, acquisitions and strategic relationships. The Company also aims to offer competitive rates and services to meet stakeholder needs and enhance the value of its natural gas pipeline assets.

Grow the North American pipeline and related infrastructure business
TransCanada is pursuing the development of greenfield and brownfield pipeline projects to grow its North American pipeline and related infrastructure business. These include frontier natural gas pipeline projects such as the Mackenzie Gas Pipeline (MGP) and the Alaska Pipeline as well as crude oil pipeline projects to meet the growing demand for transportation of Alberta oilsands production.

Other possible avenues of growth include:

- Acquiring synergistic natural gas transmission assets that complement TransCanada's existing core regions;
- Acquiring partners' interests in associated pipelines to enhance strategic control, profitability and value; and
- Acquiring stand-alone gas transmission enterprises in new regions of North America where critical mass and solid competitive advantage can be established.

The Company is also pursuing the development of natural gas pipeline infrastructure and associated LNG regasification terminals in Mexico and aims to grow pipeline earnings from PipeLines LP through acquisitions and organic growth.

Maximize the long-term value of existing power generation and power marketing and related businesses
TransCanada aims to maximize the long-term value of existing power generation and power marketing and related businesses, such as unregulated natural gas storage. The Company's approach involves engaging in marketing activities – guided by strategic criteria and defined risk boundaries – that optimize the value of owned assets, as well as exercising disciplined asset management and being actively involved in regulatory and market developments.

Grow North American power and energy businesses
The Company is focusing primarily on the core western and eastern regions to grow its North American power and energy businesses. Consideration will be given to new markets with attractive fundamentals where TransCanada can take advantage of its competencies to enhance its competitive strengths. There is a continued focus on low-cost, base-load power assets or assets backed by firm long-term contracts with reputable counterparties. The Company is also pursuing the development of LNG regasification terminals and associated natural gas pipeline infrastructure terminals to feed TransCanada's gas transmission grids in Eastern Canada and the U.S. Northeast, Pacific Northwest, and Gulf of Mexico. Greenfield development and acquisition of power generation, transmission and natural gas storage will be considered if they meet the Company's rigorous strategic and value creation criteria.

Drive for operational excellence
TransCanada maintains a commitment to provide safe, low-cost, reliable and responsible service to customers under its operational excellence business model. The Company will continue to focus efforts in this critical area on efficiencies, operational reliability, the environment and safety.

Maximize TransCanada's competitive strength and enduring value
In addition to the strategies discussed above, a number of other initiatives are being pursued in order to maximize TransCanada's competitive strength and enduring value. These include:

- Managing relationships with key stakeholder groups;
- Managing counterparty and commodity exposures within the Company's limits;
- Maintaining high standards in corporate governance practices;
- Enhancing strategic thinking, analysis and constructive debate that lead to astute investment decision-making;
- Attracting, retaining and engaging employees to maximize performance; and
- Maintaining access to abundant, low-cost capital in all market environments.

CONSOLIDATED FINANCIAL REVIEW

SELECTED THREE-YEAR CONSOLIDATED FINANCIAL DATA[1]
(millions of dollars, except per share amounts)

	2007	2006	2005
Income Statement			
Revenues	**8,828**	7,520	6,124
Net income			
Continuing operations	**1,223**	1,051	1,209
Discontinued operations	**–**	28	–
	1,223	1,079	1,209
Comparable earnings[2]	**1,107**	925	839
Per Common Share Data			
Net income – basic			
Continuing operations	**$2.31**	$2.15	$2.49
Discontinued operations	**–**	0.06	–
	$2.31	$2.21	$2.49
Net income – diluted			
Continuing operations	**$2.30**	$2.14	$2.47
Discontinued operations	**–**	0.06	–
	$2.30	$2.20	$2.47
Comparable earnings per share[2]	**$2.09**	$1.90	$1.72
Dividends declared	**$1.36**	$1.28	$1.22
Summarized Cash Flow			
Funds generated from operations[2]	**2,621**	2,378	1,951
Decrease/(increase) in operating working capital	**215**	(303)	(49)
Net cash provided by operations	**2,836**	2,075	1,902
Balance Sheet			
Total assets	**30,330**	25,909	24,113
Total long-term liabilities	**16,511**	14,464	13,012

(1) The selected three-year consolidated financial data is based on the Company's financial statements which are prepared in accordance with Canadian generally accepted accounting principles (GAAP).

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

HIGHLIGHTS

Net Income

- Net income and net income from continuing operations (net earnings) was $1,223 million or $2.31 per share in 2007 compared to net income of $1,079 million or $2.21 per share and net earnings of $1,051 million or $2.15 per share in 2006.

Comparable Earnings

- TransCanada's comparable earnings in 2007 excluded favourable income tax adjustments of $102 million and a gain of $14 million on sale of land. Comparable earnings increased $182 million to $1,107 million or $2.09 per share in 2007 compared to $925 million or $1.90 per share in 2006.

Cash from Operations

- Net cash provided by operations was $2,836 million in 2007, an increase of $761 million from 2006.
- Funds generated from operations were $2,621 million in 2007, an increase of $243 million from 2006, due primarily to increased earnings.

Investing Activities

- TransCanada invested approximately $5.9 billion in its Pipelines and Energy businesses in 2007, comprised primarily of the following:
  - The Company completed the acquisition, in February 2007, of ANR and acquired an additional 3.6 per cent interest in Great Lakes for a total of US$3.4 billion, subject to certain post-closing adjustments, including US$491 million of assumed long-term debt. The additional interest in Great Lakes increased TransCanada's direct ownership to 53.6 per cent.
  - PipeLines LP completed its acquisition in February 2007 of a 46.4 per cent interest in Great Lakes for US$942 million, subject to certain post-closing adjustments, including US$209 million of assumed long-term debt.

Financing Activities

- TransCanada issued approximately $2.6 billion of Long-Term Debt, US$1.0 billion of Junior Subordinated Notes and approximately $1.9 billion of Common Shares in 2007, comprised primarily of:
  - TransCanada issued US$1.0 billion of Senior Unsecured Notes in October 2007.
  - The Company entered into an agreement in February 2007 for a US$1.0-billion committed five-year term and revolving credit facility.
  - PipeLines LP increased the size of its revolving credit and term loan to US$950 million from US$410 million in February 2007.
  - TransCanada issued US$1.0 billion of Junior Subordinated Notes in April 2007.
  - The issue of 45.4 million common shares at $38.00 each in first-quarter 2007, resulted in gross proceeds of approximately $1.7 billion.
  - In accordance with its Dividend Reinvestment and Share Purchase Plan (DRP), TransCanada issued 4.1 million common shares from treasury in 2007 in lieu of making cash dividend payments totalling $157 million.
- PipeLines LP completed a private placement offering in February 2007 of 17.4 million common units at a price of US$34.57 per unit for gross proceeds of US$600 million. TransCanada acquired 50 per cent of the units for US$300 million and made an additional investment of approximately US$12 million to maintain its general partner interest, increasing its total ownership to 32.1 per cent from 13.4 per cent.
- The Company redeemed US$460 million of preferred securities in July 2007.
- The Company entered into an agreement in February 2007 for a US$2.2-billion one-year bridge loan facility.

Balance Sheet

- Total assets increased by $4.4 billion to $30.3 billion in 2007 compared with 2006, due primarily to the ANR and Great Lakes acquisitions.
- TransCanada's Shareholders' Equity increased by $2.1 billion to $9.8 billion in 2007 compared with the previous year.

Dividend

- On January 28, 2008, the Board of Directors of TransCanada increased the quarterly dividend on the Company's outstanding common shares for the quarter ending March 31, 2008 by six per cent to $0.36 per share from $0.34 per share. This was the eighth consecutive annual increase in the common share dividend.

Refer to "Results of Operations" below and to the "Liquidity and Capital Resources" section of this MD&A for further discussion of these highlights.

RESULTS OF OPERATIONS

Net income was $1,223 million or $2.31 per share in 2007 compared to $1,079 million or $2.21 per share in 2006 and $1,209 million or $2.49 per share in 2005. Results in 2006 included net income from discontinued operations of $28 million or $0.06 per share, reflecting bankruptcy settlements with Mirant Corporation and certain of its subsidiaries (Mirant) related to their transactions with TransCanada's Gas Marketing business. TransCanada divested its Gas Marketing business in 2001.

Net earnings were $1,223 million or $2.31 per share in 2007 compared to $1,051 million or $2.15 per share in 2006 and $1,209 million or $2.49 per share in 2005. Net earnings in 2007 included $102 million of favourable income tax adjustments and an after-tax gain of $14 million on the sale of land. Net earnings in 2006 included $95 million of favourable income tax adjustments, an $18-million after-tax bankruptcy settlement with Mirant and an after-tax gain of $13 million from the sale of TransCanada's general partner interest in Northern Border Partners, L.P. Net earnings of $1,209 million in 2005 included after-tax gains of $193 million on the sale of the Company's interest in TransCanada Power, L.P. (Power LP), $115 million on the sale of the Company's interest in P.T. Paiton Energy Company (Paiton Energy), $49 million on the sale of PipeLines LP units, and $13 million arising from a Canadian Mainline tolls settlement adjustment related to 2004 earnings.

Excluding the above-noted items, comparable earnings for the years 2007, 2006 and 2005 were $1,107 million ($2.09 per share), $925 million ($1.90 per share) and $839 million ($1.72 per share), respectively. Comparable earnings in 2007 increased $182 million or $0.19 per share compared to 2006 due primarily to additional earnings from the acquisition of ANR in February 2007 and the first full year of earnings from the Bécancour cogeneration plant and the Edson gas storage facility as well as positive impacts from rate case settlements for the GTN System and the Canadian Mainline. These increases were partially offset by a lower contribution by Bruce Power A L.P. (Bruce A) and Bruce Power L.P. (Bruce B) (collectively, Bruce Power) in 2007.

Comparable earnings increased $86 million or $0.18 per share in 2006 compared to 2005. The increase was due primarily to significantly higher operating income from Western Power, Eastern Power and the Company's investment in Bruce Power. The higher operating income was partially offset by decreased Pipelines results as net earnings from the Canadian Mainline and the Alberta System declined due to lower approved rates of return on common equity (ROE) and lower average investment bases in 2006. In addition, the Company's Other Pipelines businesses and the GTN System and North Baja (collectively, GTN) experienced lower earnings in 2006.

Results from each business segment 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. 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 other things, 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, regulatory processes and decisions, changes in environmental and other laws and regulations, competitive factors in the pipeline and energy industry sectors, construction and completion of capital projects, labour, equipment and material costs, access to capital markets, interest and currency exchange rates, technological developments and the current economic conditions in North America. By its nature, forward-looking information is subject to various risks and uncertainties, 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 to not 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 to not 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", "funds generated from operations" and "operating income" 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 are unlikely to be comparable to similar measures presented by other entities. Management of TransCanada uses non-GAAP measures to increase its ability to compare financial results between reporting periods and to enhance its understanding of operating performance, liquidity and ability to generate funds to finance operations. 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.

Comparable earnings comprise net earnings adjusted for specific items that are significant but not typical of the Company's operations. Specific items are subjective, however, management uses its best judgement and informed decision-making when identifying items to be excluded in calculating comparable earnings. Specific items may include but are not limited to certain income tax refunds and adjustments, gains or losses on sales of assets, legal settlements, and bankruptcy settlements with former customers. The table in the "Segment Results-at-a-Glance" section of this MD&A presents a reconciliation of comparable earnings to net income. Comparable earnings per share is calculated by dividing comparable earnings by the weighted average number of shares outstanding for the period.

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 "Liquidity and Capital Resources" section of this MD&A.

Operating Income is reported in the Company's Energy business segment and comprises revenues less operating expenses as shown on the consolidated income statement. A reconciliation of operating income to net earnings is presented in the Energy section of this MD&A.

OUTLOOK

The Company's net earnings and cash flow, combined with a strong balance sheet, are expected to continue to provide the financial flexibility TransCanada will need in 2008 and beyond to complete its current capital expenditure program and continue to pursue opportunities and create additional long-term value for its shareholders.

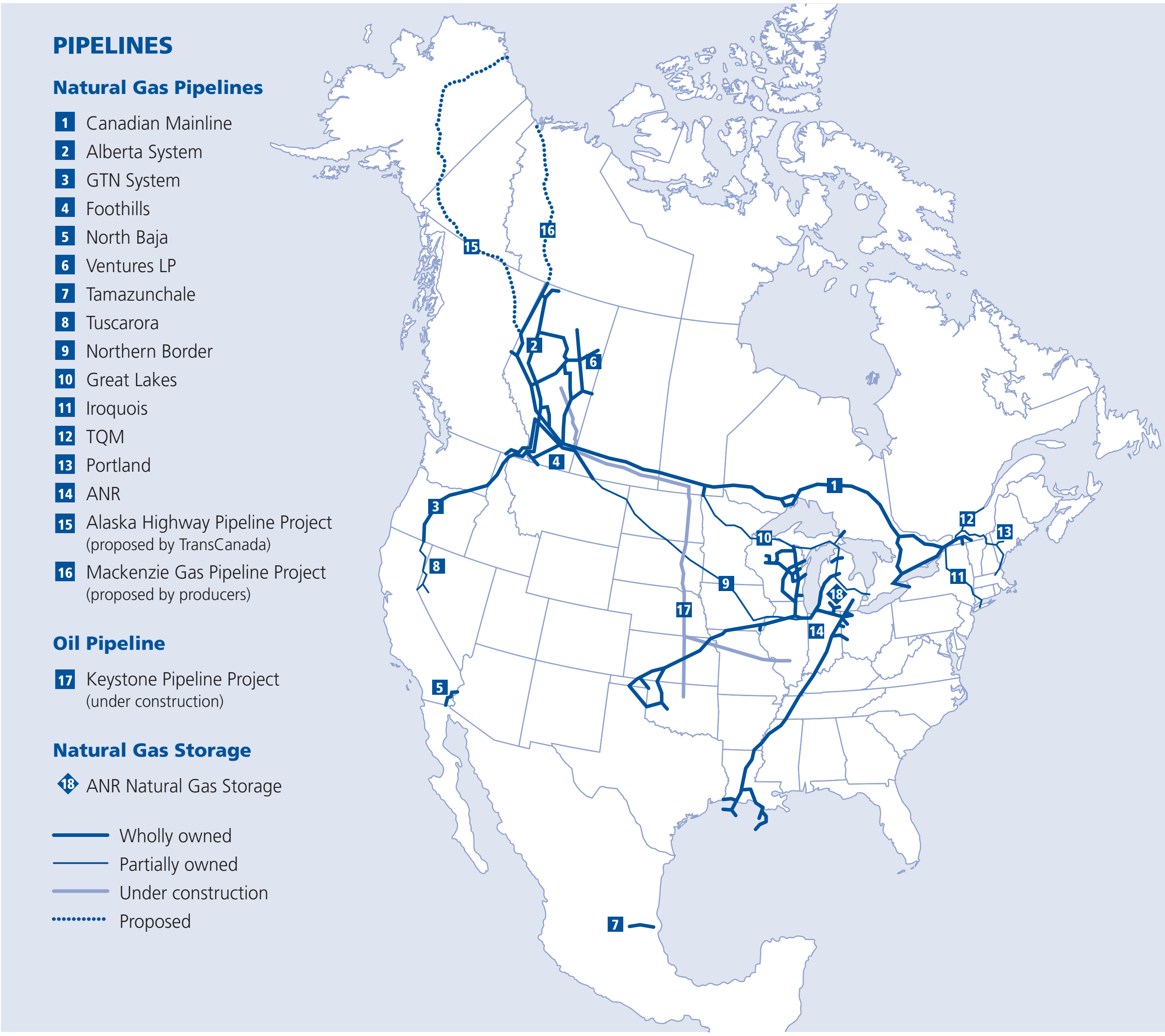
TransCanada views diligence and discipline as important elements of its strategy for long-term growth in its Pipelines and Energy businesses. In 2008, the Company will continue to implement its strategy and grow its Pipelines and Energy businesses as discussed in the "TransCanada's Strategy" section of this MD&A.

The Company's results in 2008 may be affected positively or negatively by a number of factors and developments as discussed throughout this MD&A, including in the "Forward-Looking Information" section. Refer to the "Pipelines – Outlook", "Energy – Outlook" and "Corporate – Outlook" sections of this MD&A for further discussion regarding outlook.

SEGMENT RESULTS-AT-A-GLANCE
Reconciliation of Comparable Earnings to Net Income

Year ended December 31 *(millions of dollars except per share amounts)*	**2007**	2006	2005
Pipelines			
Comparable earnings	**686**	529	617
Specific items:			
Bankruptcy settlement with Mirant	**–**	18	–
Gain on sale of Northern Border Partners, L.P. interest	**–**	13	–
Gain on sale of PipeLines LP units	**–**	–	49
Canadian Mainline NEB decision related to 2004	**–**	–	13
Net earnings	**686**	560	679
Energy			
Comparable earnings	**466**	429	258
Specific items:			
Income tax reassessments and adjustments	**34**	23	–
Gain on sale of land	**14**	–	–
Gain on sale of Power LP units	**–**	–	193
Gain on sale of Paiton Energy	**–**	–	115
Net earnings	**514**	452	566
Corporate			
Comparable expenses	**(45)**	(33)	(36)
Specific item:			
Income tax reassessments and adjustments	**68**	72	–
Net earnings	**23**	39	(36)
Net Income			
Continuing operations[1]	**1,223**	1,051	1,209
Discontinued operations	**–**	28	–
Net Income	**1,223**	1,079	1,209
Comparable Earnings[1]	**1,107**	925	839
Net Income per Share			
Continuing operations[2]	**$2.31**	$2.15	$2.49
Discontinued operations	**–**	0.06	–
Basic	**$2.31**	$2.21	$2.49
Comparable Earnings per Share[2]	**$2.09**	$1.90	$1.72

[1] **Comparable Earnings**	**1,107**	925	839
Specific items (net of tax, where applicable):			
Income tax reassessments and adjustments	**102**	95	–
Gain on sale of land	**14**	–	–
Bankruptcy settlement with Mirant	**–**	18	–
Gain on sale of Northern Border Partners, L.P. interest	**–**	13	–
Gain on sale of Power LP units	**–**	–	193
Gain on sale of Paiton Energy	**–**	–	115
Gain on sale of PipeLines LP units	**–**	–	49
Canadian Mainline NEB decision related to 2004			13
Net Income from Continuing Operations	**1,223**	1,051	1,209
[2] **Comparable Earnings Per Share**	**$2.09**	$1.90	$1.72
Specific items – per share:			
Income tax reassessments and adjustments	**0.19**	0.18	–
Gain on sale of land	**0.03**	–	–
Bankruptcy settlement with Mirant	**–**	0.04	–
Gain on sale of Northern Border Partners, L.P. interest	**–**	0.03	–
Gain on sale of Power LP units	**–**	–	0.40
Gain on sale of Paiton Energy	**–**	–	0.24
Gain on sale of PipeLines LP units	**–**	–	0.10
Canadian Mainline NEB decision related to 2004			0.03
Net Income per Share from Continuing Operations	**$2.31**	$2.15	$2.49



CANADIAN MAINLINE Owned 100 per cent by TransCanada, the Canadian Mainline is a 14,957-km natural gas transmission system in Canada that extends 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 Owned 100 per cent by TransCanada, the Alberta System is a 23,570-km natural gas transmission system in Alberta. One of the largest transmission systems in North America, it gathers natural gas for use within the province and delivers it to provincial boundary points for connection with the Company's Canadian Mainline and Foothills natural gas pipelines as well as the natural gas pipelines of other companies.

ANR Owned 100 per cent by TransCanada, the 17,000-km ANR transmission system transports natural gas from producing fields located primarily in Texas and Oklahoma on its southwest leg and in the Gulf of Mexico and Louisiana on its southeast leg. The system extends to markets located mainly in Wisconsin, Michigan, Illinois, Ohio and Indiana. ANR's natural gas pipeline also connects with other natural gas pipelines to give access to diverse sources of North American supply including Western Canada and the Rocky Mountain supply basin, and a variety of markets in the midwestern and northeastern U.S. ANR also owns and operates regulated underground natural gas storage facilities in Michigan with a total capacity of approximately 235 Bcf.

GTN SYSTEM Owned 100 per cent by TransCanada, the GTN System is a 2,174-km natural gas transmission system that links Foothills with Pacific Gas and Electric Company's California Gas Transmission System, with Williams Companies, Inc.'s Northwest Pipeline in Washington and Oregon, and with Tuscarora.

FOOTHILLS Owned 100 per cent by TransCanada, the 1,241-km Foothills transmission system in Western Canada carries 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. TransCanada's BC System was integrated into Foothills effective April 1, 2007.

NORTH BAJA Owned 100 per cent by TransCanada, the North Baja natural gas transmission system extends 129 km from Ehrenberg in southwestern Arizona to a point near Ogilby, California on the California/Mexico border and connects with the Gasoducto Bajanorte natural gas pipeline system in Mexico.

GREAT LAKES Owned 53.6 per cent by TransCanada and 46.4 per cent by PipeLines LP, the 3,404-km Great Lakes natural gas transmission system connects with the Canadian Mainline at Emerson, Manitoba, and serves markets in Central Canada and the midwestern U.S. TransCanada operates Great Lakes and effectively owns 68.5 per cent of the system through its 53.6 per cent direct ownership interest and its indirect ownership through its 32.1 per cent interest in PipeLines LP.

NORTHERN BORDER Owned 50 per cent by PipeLines LP, the 2,250-km Northern Border natural gas transmission system serves the U.S. Midwest from a connection with Foothills near Monchy, Saskatchewan. TransCanada operates Northern Border and effectively owns 16.1 per cent of the system through its 32.1 per cent interest in PipeLines LP.

TUSCARORA Owned 100 per cent by PipeLines LP, Tuscarora is a 491-km pipeline system transporting natural gas from the GTN System at Malin, Oregon, to Wadsworth, Nevada, with delivery points in northeastern California and northwestern Nevada. TransCanada operates Tuscarora and its 32.1 per cent interest in PipeLines LP gives TransCanada a 32.1 per cent ownership interest in the system.

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

TRANSGAS Owned 46.5 per cent by TransCanada, TransGas is a 344-km natural gas pipeline system extending from Mariquita in the central region of Colombia to Cali in southwestern Colombia.

PORTLAND Owned 61.7 per cent by TransCanada, Portland is a 474-km 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.

VENTURES LP Owned 100 per cent by TransCanada, Ventures LP has a 121-km pipeline and related facilities that supply natural gas to the oilsands region of northern Alberta as well as a 27-km pipeline that supplies natural gas to a petrochemical complex at Joffre, Alberta.

TAMAZUNCHALE Owned 100 per cent by TransCanada, the 130-km Tamazunchale natural gas pipeline in east central Mexico extends from the facilities of Pemex Gas near Naranjos, Veracruz, to an electricity generating station near Tamazunchale, San Luis Potosi. Tamazunchale went into service on December 1, 2006.

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

GAS PACIFICO/INNERGY Owned 30 per cent by TransCanada, Gas Pacifico is a 540-km 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.

KEYSTONE Owned 50 per cent by TransCanada, Keystone is a 3,456-km oil pipeline project under construction that is expected to transport crude oil from Hardisty, Alberta to U.S. midwest markets at Wood River and Patoka in Illinois, and to Cushing, Oklahoma.

PIPELINES – HIGHLIGHTS

Net Earnings

- Net earnings from Pipelines were $686 million in 2007, an increase of $126 million from $560 million in 2006. The growth was due primarily to the acquisitions of ANR and additional interest in Great Lakes, higher earnings as a result of the Canadian Mainline and GTN System rate settlements, and an increased ownership interest in PipeLines LP.

Expanding Asset Base

- TransCanada expanded its North American natural gas pipeline and storage operations through its US$3.4-billion acquisitions of ANR and additional interest in Great Lakes in 2007.
- At December 31, 2007, TransCanada has secured sufficient long-term contracts to underpin construction of the US$5.2-billion Keystone oil pipeline, including an extension to Cushing, Oklahoma, in which the Company holds a 50 per cent ownership interest.
- TransCanada applied to the Alberta Energy and Utilities Board (EUB) in late 2007 for approval to further expand its Alberta System by adding 300 km of natural gas pipeline at an estimated total capital cost of $983 million.
- TransCanada received approval from the EUB in 2007 to construct four new natural gas transmission facilities to serve the firm intra-Alberta delivery contract requirements of oilsands developers in the Fort McMurray, Alberta area. The capital cost of the four pipeline facilities, which total 150 km, together with a 15-MW compression facility, is expected to be $367 million.

Canadian Mainline

- The National Energy Board (NEB) approved a negotiated five-year settlement of Canadian Mainline tolls, which included a deemed common equity ratio of 40 per cent and certain performance-based and operating, maintenance and administration (OM&A) cost-saving incentive arrangements.

Alberta System

- The Alberta System operated under the terms of the 2005-2007 Revenue Requirement Settlement in 2007 and is currently negotiating a settlement with stakeholders for 2008.

GTN System

- The Federal Energy Regulatory Commission (FERC) approved in January 2008 the GTN System's uncontested rate case settlement. Under the settlement, the GTN System's rates increased by approximately 27 per cent, effective January 1, 2007.

Foothills

- After receiving NEB approval, the BC System was integrated into Foothills effective April 1, 2007.

Other Pipelines

- TransCanada acquired approximately eight million units of PipeLines LP in February 2007, increasing the Company's ownership interest to 32.1 per cent. Through its increased ownership interest in PipeLines LP, TransCanada increased its effective ownership in Great Lakes to 68.5 per cent.

PIPELINES RESULTS-AT-A-GLANCE
Year ended December 31 *(millions of dollars)*

	2007	2006	2005
Wholly Owned Pipelines			
Canadian Mainline	**273**	239	270
Alberta System	**138**	136	150
ANR[1]	**104**		
GTN	**58**	46	71
Foothills[2]	**26**	27	27
	599	448	518
Other Pipelines			
Great Lakes[3]	**47**	44	46
PipeLines LP[4]	**18**	4	9
Iroquois	**15**	15	17
TransGas	**15**	11	11
Portland	**11**	13	11
Ventures LP	**11**	12	12
Tamazunchale[5]	**10**	2	
TQM	**6**	7	7
Gas Pacifico/INNERGY[6]	**3**	8	6
Northern Development	**(7)**	(5)	(4)
General, administrative, support costs and other	**(42)**	(30)	(16)
	87	81	99
Comparable earnings[7]	**686**	529	617
Bankruptcy settlement with Mirant	**–**	18	–
Gain on sale of Northern Border Partners, L.P. interest	**–**	13	–
Gain on sale of PipeLines LP units	**–**	–	49
Canadian Mainline NEB decision related to 2004	**–**	–	13
Net earnings	**686**	560	679

(1) ANR was acquired February 22, 2007.

(2) Foothills' results reflect the combined operations of Foothills and the BC System.

(3) Great Lakes' results reflect TransCanada's 53.6 per cent ownership in Great Lakes since February 22, 2007, and 50 per cent ownership prior to this date.

(4) PipeLines LP's results include a 46.4 per cent ownership interest in Great Lakes since February 22, 2007, as well as an additional 20 per cent ownership of Northern Border since April 6, 2006, and an additional 49 per cent ownership of Tuscarora since December 19, 2006. PipeLines LP's results also reflect TransCanada's 32.1 per cent ownership since February 22, 2007.

(5) Tamazunchale's results include operations since December 1, 2006.

(6) INNERGY Holdings S.A.

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

Net earnings from the Pipelines business were $686 million in 2007 compared to $560 million in 2006 and $679 million in 2005. Net earnings in 2006 included the $18-million bankruptcy settlement with Mirant and the $13-million gain on sale of TransCanada's general partner interest in Northern Border Partners, L.P. Net earnings in 2005 included the $49-million gain on sale of PipeLines LP units. Net earnings in 2005 also included a $13-million positive adjustment related to 2004 as a result of the NEB's decision in 2005 to increase the deemed common equity ratio to 36 per cent from 33 per cent under the Canadian Mainline's 2004 Tolls and Tariff Application (Phase II).

Comparable earnings from the Pipelines business were $686 million in 2007, an increase of $157 million compared to $529 million in 2006. The increase was due primarily to the acquisitions of ANR and additional interest in Great Lakes, higher earnings as a result of the Canadian Mainline and GTN System rate settlements and an increased ownership in PipeLines LP.

Comparable earnings decreased $88 million to $529 million in 2006 compared to $617 million in 2005. The decline was due primarily to lower net earnings from the Canadian Mainline, the Alberta System, GTN and Other Pipelines.

PIPELINES – FINANCIAL ANALYSIS

Canadian Mainline

The Canadian Mainline is regulated by the NEB. The NEB sets tolls that provide TransCanada with the opportunity to recover its projected costs of transporting natural gas, including a return on the Canadian Mainline's average investment base. The NEB also approves new facilities before their construction begins. Net earnings of the Canadian Mainline are affected by changes in the investment base, the ROE, the level of deemed common equity and potential incentive earnings.

In February 2007, TransCanada reached a five-year tolls settlement effective January 1, 2007 to December 31, 2011 on the Canadian Mainline. In May 2007, the NEB approved TransCanada's application of the settlement as filed, including TransCanada's request that interim tolls be made final for 2007.

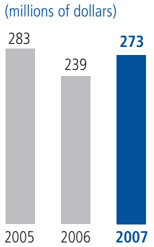
As part of the settlement, it was agreed that the cost of capital reflect an ROE on a deemed common equity ratio of 40 per cent, an increase from 36 per cent, as determined under the NEB's ROE formula. The remaining capital structure will consist of short- and long-term debt, following the agreed upon redemption of the US$460 million 8.25 per cent Preferred Securities that were included in the Canadian Mainline's capital structure.

The settlement also established certain elements of the Canadian Mainline's fixed OM&A costs for each year of the settlement. The variance between actual and agreed upon OM&A costs will accrue to TransCanada from 2007 to 2009, and will be shared equally between TransCanada and its customers in 2010 and 2011. The settlement also allows for performance-based incentive arrangements that will provide mutual benefits to both TransCanada and its customers.

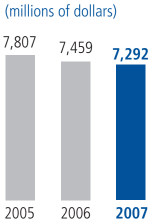
Net earnings of $273 million in 2007 were $34 million higher than 2006 net earnings of $239 million. The increase primarily reflected the positive impact of the increase in deemed common equity ratio in the Canadian Mainline tolls settlement, performance-based incentive arrangements and OM&A cost savings, partially offset by a lower allowed ROE of 8.46 per cent in 2007 (8.88 per cent in 2006), as determined under the NEB's formula, and a lower average investment base.

Canadian Mainline generated comparable earnings of $239 million in 2006, a decrease of $31 million from 2005. The decrease was due primarily to a combination of a lower allowed ROE and a lower average investment base in 2006

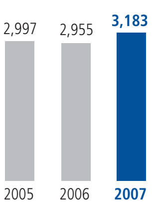
Canadian Mainline Net Earnings (millions of dollars)



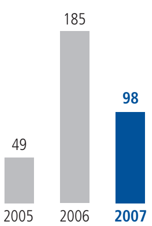
Canadian Mainline Average Investment Base (millions of dollars)



Canadian Mainline Throughput Volumes (Bcf)



Canadian Mainline Capital Expenditures (millions of dollars)



compared to 2005. Comparable earnings in 2005 excluded the $13-million positive adjustment from the NEB decision related to 2004. TransCanada reached a tolls settlement with its Canadian Mainline customers and other interested parties that included an NEB-allowed ROE of 8.88 per cent for 2006, which was determined under the NEB's return adjustment formula on a deemed common equity ratio of 36 per cent. The NEB-allowed ROE for 2005 was 9.46 per cent.

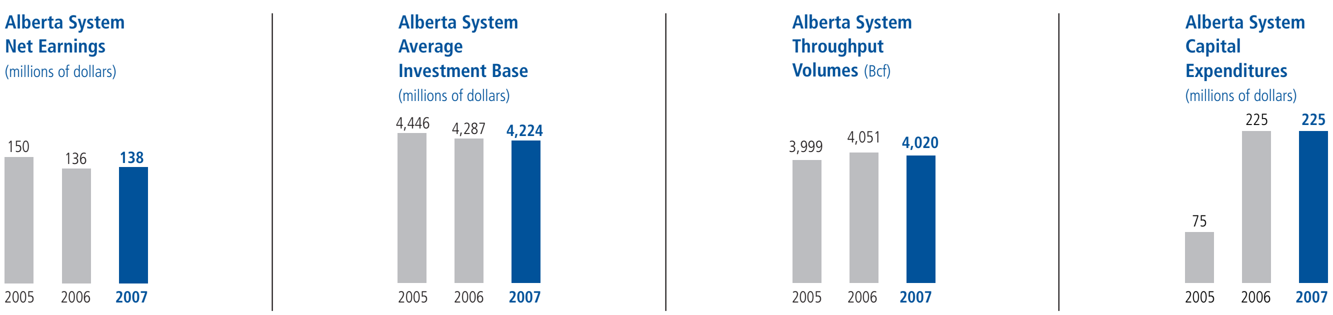
Alberta System

The EUB was reorganized into the Energy Resources Conservation Board and the Alberta Utilities Commission (AUC) effective January 1, 2008. The AUC regulates construction and operation of facilities and the terms and conditions of services, including rates, for the Alberta System, primarily under the provisions of the *Gas Utilities Act* and the *Pipeline Act*.

The Alberta System has been operating for the past three years under the 2005-2007 Revenue Requirement Settlement. The settlement addresses all elements of the Alberta System including OM&A costs, ROE, depreciation and income and municipal taxes. The settlement fixed OM&A costs at $207 million for 2007, $201 million for 2006, and $193 million for 2005. In each year, any variance between actual OM&A and other fixed costs and those agreed to in the settlement accrued to TransCanada. The majority of other cost elements of the 2005, 2006 and 2007 revenue requirements are treated on a flow-through basis.

Alberta System net earnings of $138 million in 2007 were $2 million higher than in 2006. The increase was due primarily to OM&A cost savings, partially offset by a lower allowed ROE and a lower investment base in 2007. The allowed ROE prescribed by the EUB was 8.51 per cent in 2007 compared with 8.93 per cent in 2006 on deemed common equity of 35 per cent.

Net earnings of $136 million in 2006 were $14 million lower than in 2005. The decrease was due primarily to a lower investment base and a lower allowed ROE in 2006. The allowed ROE prescribed by the EUB was 9.50 per cent in 2005 on deemed common equity of 35 per cent.



ANR

TransCanada completed the acquisition of ANR on February 22, 2007 and included its net earnings from this date. The operations of ANR are regulated primarily by the FERC. ANR provides natural gas transportation, storage and various capacity-related services to a variety of customers in both the U.S. and Canada. The transmission system has a peak-day capacity of 6.8 Bcf/d. ANR also owns and operates numerous underground natural gas storage facilities in Michigan. ANR's FERC-regulated natural gas storage and transportation services operate under current FERC-approved tariff rates. These tariffs include maximum and minimum rate levels for services and permit ANR to discount or negotiate rates on a non-discriminatory basis. ANR Pipeline's rates were established pursuant to a settlement approved by a FERC order issued in February 1998 and the settlement rates became effective November 1, 1997. ANR Storage Company's rates were established pursuant to a settlement approved by the FERC in April 1990 and these settlement rates became effective June 1, 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 revenues are derived primarily from its interstate natural gas transmission and storage, gathering and related services. Due to the seasonal nature of the business, ANR's volumes, revenues and net earnings are generally expected to be higher in the winter months. ANR's net earnings were $104 million from the date of its acquisition by TransCanada on February 22, 2007, to December 31, 2007 and were in line with the Company's expectations.

GTN

The FERC regulates GTN. Both of GTN's systems, the GTN System and North Baja, are subject to FERC-approved tariffs that establish maximum and minimum rates for various services. The systems are permitted to discount or negotiate these rates on a non-discriminatory basis. On October 31, 2007, the GTN System filed a Stipulation and Agreement with the FERC that comprises an uncontested settlement of all aspects of its 2006 General Rate Case. The settlement rates went into effect on an interim basis on November 1, 2007, in accordance with the FERC's Order dated November 16, 2007. The FERC approved the settlement on January 7, 2008, with settlement rates effective January 1, 2007. GTN's financial results in 2007 reflect the terms of the settlement. The net earnings of GTN are affected by variations in contracted volume levels, volumes delivered and prices charged under the various service types that are provided, as well as by variations in the costs of providing services.

GTN's comparable earnings increased $12 million in 2007, compared to 2006 due primarily to the positive impact of the rate case settlement, partially offset by lower long-term firm contracted volumes and a weaker U.S. dollar in 2007. In addition, comparable earnings in 2007 were negatively affected by a higher provision taken in 2007 for non-payment of contract revenues from a subsidiary of Calpine Corporation (Calpine) that filed for bankruptcy protection.

Net earnings were $46 million in 2006, a $25-million decrease from 2005. This decrease was due primarily to lower transportation revenues, higher operating costs, the impact of the weaker U.S. dollar and the provision for non-payment of contract revenues from the Calpine subsidiary.

Other Pipelines

TransCanada's direct and indirect investments in various natural gas pipelines and its project development activities relating to natural gas and oil transmission opportunities throughout North America are included in Other Pipelines.

TransCanada's comparable earnings from Other Pipelines were $87 million in 2007 compared to $81 million in 2006. The increase was due primarily to higher earnings in PipeLines LP, which were affected positively by TransCanada's increased ownership interests in PipeLines LP and Great Lakes, and Tamazunchale, which completed its first full year of operations in 2007. These increases were partially offset by higher project development and support costs associated with growing the Pipelines business, the effects of the weaker U.S. dollar in 2007, and proceeds of a bankruptcy settlement received by Portland in 2006.

Comparable earnings from Other Pipelines were $81 million in 2006, $18 million lower than in 2005. The decrease was due primarily to higher project development and support costs associated with growing the Pipelines business, reduced ownership in PipeLines LP, the effects of the weaker U.S. dollar, and proceeds of bankruptcy settlements received by Iroquois in 2005. These decreases were partially offset by higher net earnings from Portland due to the proceeds it received in 2006 from the bankruptcy settlement.

PIPELINES – OPPORTUNITIES AND DEVELOPMENTS

Keystone

Keystone is expected to extend 3,456 km and is designed to deliver 590,000 Bbl/d of crude oil from Hardisty, Alberta, to U.S. Midwest markets at Wood River and Patoka in Illinois, and to Cushing, Oklahoma. The Company has currently secured long-term contracts for a total of 495,000 Bbl/d with an average duration of 18 years. Deliveries to Patoka are expected to begin in late 2009.

TransCanada and Keystone Canada received regulatory approval from the NEB in 2007 to transfer a portion of TransCanada's Canadian Mainline natural gas transmission facilities to Keystone Canada, and to construct and operate new oil pipeline facilities in Canada. Keystone Canada filed an application with the NEB in November 2007 to add new pumping facilities to accommodate the increase in scope and scale of the project. An NEB oral hearing is scheduled to commence in April 2008.

Keystone U.S. received, from the U.S. Department of State in January 2008, the Final Environmental Impact Statement (FEIS) regarding construction of the Keystone U.S. pipeline and its Cushing extension. The FEIS stated the pipeline would result in limited adverse environmental impacts. The FEIS is a requirement to proceed with the Presidential Permit process, which governs the construction and operation of facilities at the U.S.-Canada border crossing. The Presidential Permit is expected to be issued in March 2008.

ConocoPhillips contributed $207 million to acquire a 50 per cent ownership interest in Keystone in December 2007. Affiliates of TransCanada will be responsible for constructing and operating Keystone, which is expected to have a capital cost of approximately US$5.2 billion.

Canadian Mainline

In July 2007, the NEB approved TransCanada's request to add a new LNG receipt point at Gros Cacouna, Québec, as well as its request to calculate tolls for service from this point on a rolled-in basis. The approvals will be effective on the date the facilities required to connect the Gros Cacouna receipt point are placed in service.

On November 29, 2007, the NEB announced that, pursuant to its formula, the 2008 allowed ROE for NEB-regulated pipelines, including the Canadian Mainline, will be 8.71 per cent, up from 8.46 per cent in 2007.

Alberta System

TransCanada received approval from the EUB in July 2007 to initiate negotiations on the Alberta System revenue requirement with the intent of reaching a settlement for a term of up to three years commencing January 1, 2008. Settlement negotiations with stakeholders are progressing. TransCanada has a requirement to file a 2008 General Rate application or a settlement in first-quarter 2008.

On November 30, 2007 the EUB finalized the Alberta System's 2008 allowed ROE at 8.75 per cent, compared to 8.51 per cent in 2007.

TransCanada received approval from the EUB in 2007 to construct four new natural gas transmission facilities to serve the firm intra-Alberta delivery contract requirements of oilsands developers in the Fort McMurray, Alberta area. The capital cost of the four pipeline facilities, which total 150 km, together with a 15-MW compression facility are expected to be $367 million.

TransCanada submitted an application to the EUB in November 2007 for a permit to construct the North Central Corridor expansion, which comprises a 300-km natural gas pipeline and associated facilities on the northern section of the Alberta System. The expansion, if approved, will connect the northwest portion of the Alberta System with the northeast portion of the system. The estimated capital cost of this expansion is $983 million. The project is expected to be completed in two stages, the first one beginning in late 2008 with an in-service date of April 1, 2009 and the second one with an in-service date of April 1, 2010.

ANR

As of December 31, 2007, ANR substantially completed a project that increased its saleable natural gas storage capacity by 13 Bcf, of which 10 Bcf was previously used for system operations. Construction has commenced on a second storage enhancement project, which is expected to increase ANR's natural gas storage capacity by 14 Bcf in 2008.

ANR is considering an additional storage expansion project, which, along with the utilization of other natural gas pipeline assets across TransCanada's system, is intended to allow customers to access additional storage and markets. ANR is also pursuing potential additions of supply on both its southwest and southeast legs. Supply on the southwest leg was increased in early 2008 as a result of an interconnect with the Rockies Express natural gas pipeline, which commenced service in January 2008. There is potential for new supply on the southeast leg from LNG additions, shale gas from the mid-continent, and a potential additional interconnect with the Rockies Express pipeline.

GTN

In August 2007, Gas Transmission Northwest Corporation (GTNC), a wholly owned subsidiary of TransCanada, and Northwest Natural Gas Company (NW Natural) formed an equally owned joint venture, Palomar Gas Transmission LLC (Palomar), to develop a 354-km (220 mile) natural gas pipeline to serve the Oregon, Pacific Northwest and Western U.S markets. The proposed Palomar pipeline would connect TransCanada's existing GTN System in central Oregon with NW Natural's distribution system near Molalla, Oregon, and could be extended to a proposed pipeline near the town of Wauna, Oregon. The Palomar pipeline is in the preliminary stages of the FERC permitting process.

North Baja

North Baja received a FERC expansion certificate in October 2007 authorizing modifications that would allow it to import natural gas from the Costa Azul LNG terminal in northwestern Mexico, which is nearing completion. The imported gas would serve markets in California and the U.S. Southwest. The FERC certificate authorizes phased expansion of North Baja. The first phase of the expansion includes system modifications to allow for bi-directional natural gas flow and the addition of a lateral natural gas pipeline to interconnect with a Southern California Gas Co. pipeline near Blythe, California. The first phase will also give North Baja the ability to import approximately 600 million cubic feet per day (mmcf/d) of natural gas from Mexico.

Foothills

TransCanada's BC System was integrated into Foothills in 2007. In first quarter 2007, the NEB approved the transfer of assets and finalized the revised tolls for 2007. Foothills will continue to be regulated on a complaint basis only.

Tamazunchale

The Company's Tamazunchale natural gas pipeline in Mexico is designed to transport initial volumes of 170 mmcf/d. The pipeline's capacity is expected to be expanded to approximately 430 mmcf/d, to meet the needs of two additional proposed power plants near Tamazunchale. The timing of the expansion will be driven by the Comisión Federal de Electricidad's requirements for the power plants.

Mackenzie Gas Pipeline Project

The MGP is a proposed 1,200-km natural gas pipeline to be constructed from a point near Inuvik, Northwest Territories to the northern border of Alberta, where it is expected to 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. Cumulative advances made by TransCanada in this respect totalled $137 million at December 31, 2007 and are included in Other Assets. These amounts constitute a loan to the APG, which becomes repayable only after the pipeline commences commercial operations. The total amount of the loan is expected to form part of the rate base of the pipeline and subsequently 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. Accordingly, TransCanada's ability to recover its investment is dependant upon a successful outcome of the project.

Under the terms of certain MGP agreements, TransCanada holds an option to acquire up to a five per cent equity ownership in the natural gas pipeline at the time of the decision to construct. 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.

TransCanada and the other co-venture companies involved in the MGP continue to pursue approval of the proposed project, focusing on the regulatory process and discussions with the Canadian government on fiscal framework. Project timing is uncertain and is conditional upon resolution of regulatory and fiscal matters.

Alaska Pipeline Project

TransCanada continued its discussions with Alaska North Slope producers and the State of Alaska in 2007 to advance the proposed Alaska Pipeline Project. TransCanada submitted an application in November 2007 for a license to construct the Alaska Pipeline Project under the *Alaska Gasline Inducement Act* (AGIA). The State of Alaska announced on January 4, 2008, that TransCanada had submitted a complete AGIA application and would be advancing to the Public Comment stage. No other applicant met all the AGIA requirements. If approved by the Alaska Administration and the Alaska Legislature, TransCanada could be granted the AGIA license by mid-2008. Upon receipt of the AGIA license, TransCanada will proceed with an open season to secure shipping commitments from shippers.

Foothills holds the priority right to build, own and operate the first natural gas pipeline through Canada for the transportation of Alaskan gas. This right was granted under the *Northern Pipeline Act of Canada* (NPA) following a lengthy competition hearing before the NEB in the late 1970s, which produced a decision in favour of Foothills. The NPA creates a single-window regulatory regime that is uniquely available to Foothills. It has been used by Foothills to construct facilities in Alberta, British Columbia (B.C.) and Saskatchewan that constitute a pre-build for the Alaska Pipeline Project, and to expand these facilities five times, the latest of which was in 1998. Continued development of the Alaska Pipeline Project under the NPA is expected to ensure the earliest in-service date for the project.

PIPELINES – BUSINESS RISKS

Supply, Markets and Competition

TransCanada faces competition at both the supply and market ends of its systems. This competition comes from other natural gas pipelines accessing the increasingly mature WCSB and markets served by TransCanada's pipelines. In addition, the continued expiration of long-term firm transportation (FT) contracts has resulted in significant reductions in long-term firm contracted capacity and shifts to short-term firm contracts on the Canadian Mainline, the Alberta System, Foothills and the GTN System.

TransCanada's primary source of natural gas supply is the WCSB. As of December 2006, the WCSB had remaining discovered natural gas reserves of approximately 57 trillion cubic feet and a reserves-to-production ratio of approximately nine years at current levels of production. Historically, sufficient additional reserves have been discovered on an ongoing basis to maintain the reserves-to-production ratio at close to nine years. However, gas supply is expected to decline due to a continued reduction in levels of drilling activity in the WCSB. The reduced drilling activity is a result of lower prices, higher supply costs, which include higher royalties, and the stronger Canadian dollar. TransCanada anticipates there will be excess natural gas pipeline capacity out of the WCSB in the foreseeable future as a result of capacity expansion on its wholly owned and partially owned natural gas pipelines over the past decade, competition from other pipelines, and significant growth in natural gas demand in 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. The primary areas of high activity have been deeper conventional drilling in western Alberta and in the foothills region of B.C., and coalbed methane development in central Alberta. The Alberta System has faced, and will continue to face, increasing competition from other natural gas pipelines. An emerging competitive issue for the Alberta System is the existence and access to natural gas liquids (NGL) contained in the natural gas transported by the pipeline system. In 2007, the EUB began a proceeding in relation to NGL extraction matters. The outcome of this proceeding may affect the way in which regulated natural gas pipelines compete within Alberta.

Historically, TransCanada's eastern natural gas pipeline system has been supplied by long-haul flows from the WCSB and by short-haul volumes received from storage fields and interconnecting pipelines in southwestern Ontario. Over the last few years, the Canadian Mainline has experienced reductions in long-haul flows, which have been partially offset by increases in short-haul volumes. This reflects the combined impact of new U.S. Midwest-to-Ontario pipeline capacity and lower supply available for export from the WCSB region.

Demand for natural gas in TransCanada's key eastern markets, which are served by the Canadian Mainline, is expected to continue to increase, particularly to meet the expected growth in natural gas-fired power generation. Although there are opportunities to increase market share in Canadian and U.S. export markets, TransCanada faces significant competition in these regions. 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 are now capable of receiving supplies from new natural gas pipelines that can source U.S. and Western and Atlantic Canadian supplies.

ANR's primary natural gas supply is sourced from the Gulf of Mexico and mid-continent U.S. regions, which are served by competing natural gas pipelines. ANR also has competition from other natural gas pipelines in its primary markets in the U.S. Midwest. The Gulf of Mexico region is extremely competitive given its extensive natural gas pipeline network. ANR is one of many interstate and intrastate pipelines in the region competing for new and existing production as well as for new supplies from LNG, from shale production in the mid-continent, and from the Rockies Express natural gas pipeline originating in the Rocky Mountain region. Several new natural gas pipelines are proposed or under construction to connect new supplies to the numerous pipelines in the Gulf of Mexico region. ANR competes with other natural gas pipelines in the region to attract supply to its pipeline for alternative markets and storage. The most recent changes in ANR's market region are the FERC-approved expansions of two competing pipelines, which will provide approximately 500 mmcf/d of incremental capacity into the Wisconsin market and approximately 200 mmcf/d of incremental capacity into the market extending from Chicago, Illinois, to Dawn, Ontario. The expanded transportation capacity competes directly with alternatives provided by ANR and Great Lakes, while incremental storage connections provide competitive alternatives to ANR's storage in Michigan.

The GTN System must compete with other pipelines to access natural gas supplies and markets. Transportation service capacity on the GTN System 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 the GTN System competes with the Rocky Mountain natural gas supply and with additional western Canadian supply transported by other natural gas pipelines. Historically, natural gas supplies from the WCSB have been competitively priced in relation to supplies from the other regions serving these markets. The GTN System experienced significant contract non-renewals in 2005 and 2006 as natural gas transported from the WCSB on the GTN System competed for the California and Nevada markets against supplies from the Rocky Mountain and southwestern U.S. supply basins. Recently, Pacific Gas and Electric Company, the GTN System's largest customer, filed an application with the California Public Utilities Commission (CPUC) requesting approval to commit to capacity on a proposed project out of the Rocky Mountain basin to the California border. This project has not yet been filed with the FERC and TransCanada is protesting the application filed with the CPUC.

Regulatory Financial Risk

Regulatory decisions continue to have a significant impact on the financial returns from existing investments in TransCanada's Canadian wholly owned pipelines and are expected to have a similarly significant impact on financial returns from future investments. TransCanada remains concerned that financial returns approved by regulators could potentially fail to be competitive with returns from assets with similar risk profiles. In recent years, TransCanada applied to the NEB and the EUB for an ROE of 11 per cent on 40 per cent deemed common equity for both the Canadian Mainline and the Alberta System, respectively. The NEB has reaffirmed its ROE formula and the EUB has established a generic ROE, which largely aligns with the NEB formula. Through rate applications and negotiated settlements, TransCanada has been able to improve the common equity components of its Canadian Mainline and Alberta System capital structures to the current 40 per cent and 35 per cent respectively.

TQM filed an application with the NEB in December 2007 requesting a fair return on capital, consisting of an ROE of 11 per cent on 40 per cent deemed common equity. The outcome of this proceeding may influence the regulators' view of fair financial returns on equity associated with TransCanada's other Canadian wholly owned pipelines.

Throughput Risk

As transportation contracts expire, TransCanada's U.S. natural gas pipelines are expected to be more exposed to the risk of reduced throughput and their revenues more likely to experience increased variability. Throughput risk is created by supply and market competition, gas basin pricing, economic activity, weather variability, natural gas pipeline competition and pricing of alternative fuels.

Execution and Capital Cost Risk

The construction of Keystone is subject to execution and capital cost risks, which is subject to a capital cost risk- and reward-sharing mechanism with its customers.

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

PIPELINES – OUTLOOK

Demand for natural gas and crude oil is expected to continue to grow across North America in 2008. TransCanada's Pipelines business will continue to focus on the delivery of natural gas to growing markets, connecting new supply, progressing development of new infrastructure to connect natural gas from the north and unconventional supplies such as coalbed methane and LNG, and development of the Keystone oil pipeline.

TransCanada expects producers will continue to explore and develop new fields in Western Canada, particularly in northeastern B.C. and the west central foothills regions of Alberta. There is also expected to be significant activity aimed at unconventional resources such as coalbed methane, which will be further incented starting in 2009 due to the new royalty structure in Alberta benefiting lower productivity wells.

Most of TransCanada's current expansion plans in Canadian natural gas transmission are focused on the Alberta System. New facilities are expected to be needed to expand the integrated Alberta System to reflect changes in the distribution of supply and market within Alberta, connect new discrete supply sources, as well as new delivery points, primarily in the Alberta oilsands region and the central Alberta industrial heartland.

In the U.S., TransCanada expects unconventional production will continue to be developed from the coalbed methane and tight gas sands of the Rocky Mountain region, as well as from shale plays in east Texas, southwestern Oklahoma and Arkansas. In addition, incremental supplies are anticipated from LNG imports into the U.S. Significant infrastructure is being built in the U.S. to accommodate these supply sources. The resulting growth in supply from LNG and the unconventional supply sources is likely to offer additional commercial 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 production to midwestern and eastern U.S. markets, including interconnections with ANR. The southeast leg of ANR has the capacity to transport additional volumes of LNG and mid-continent shale production as these supplies develop.

Producers continue to develop new oil supply in the WCSB. In 2008, there are several new oilsands projects that will begin production, along with growth at existing projects. Oilsands production is expected to grow from 1.2 million Bbl/d in 2007 to 3.0 million Bbl/d in 2015, while total WCSB oil supply is projected to grow from 2.5 million Bbl/d to 3.9 million Bbl/d over the same period. The primary market for this new oilsands production is the U.S., extending from the U.S. Midwest to the Gulf of Mexico region, which contains a number of very large refineries, well equipped to handle Canadian heavy crude oil blends. WCSB crude oil is expected to replace declining U.S. imports of heavy crude oil from other countries.

This increase in WCSB crude oil exports requires new pipeline capacity, including Keystone, and further expansions to the Gulf of Mexico. TransCanada will continue to pursue additional opportunities to move crude oil from the Alberta oilsands to U.S. markets.

TransCanada will continue to focus on operational excellence and on collaborative efforts with all stakeholders to achieve negotiated settlements and service options that will increase the value of the Company's business to customers and shareholders.

Earnings

The Company expects continued growth on its Alberta System. The Company anticipates a modest level of investment in its other existing Canadian natural gas pipelines, resulting in an expected continued net decline in the average investment base due to annual depreciation. A net decline in the average investment base has the effect of reducing year-over-year earnings from these assets. However, this impact will be partially mitigated in 2008 by a slight increase in the formula-based regulated ROEs. Additionally, a settlement resulting from the current negotiations on the Alberta System may provide the opportunity for additional earnings contribution in 2008. 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.

Reduced FT contract volumes due to customer defaults, reduced 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. Earnings from Pipelines' foreign operations are impacted by changes in foreign currency exchange rates. Pipelines' earnings in 2008 are expected to be positively impacted by a full year of operations from ANR and the additional interests in Great Lakes.

Certain subsidiaries of Calpine filed for bankruptcy protection in both Canada and the U.S. in 2005. Portland and GTNC have reached agreements with Calpine for allowed unsecured claims of US$125 million and US$192.5 million, respectively, in the Calpine bankruptcy. Creditors will receive shares in the re-organized Calpine and these shares will be subject to market price fluctuations as the new Calpine shares begin to trade. In February 2008, Portland and GTNC received initial distributions of 6.1 million shares and 9.4 million shares, respectively, which are expected to result in a significant increase in TransCanada's net earnings in first-quarter 2008.

Claims by NOVA Gas Transmission Limited and Foothills Pipe Lines (South B.C.) Ltd. for $31.6 million and $44.4 million, respectively, were received in cash in January 2008 and will be passed on to shippers on these systems.

Capital Expenditures

Excluding the cost of acquiring ANR and additional interests in Great Lakes, total capital spending for the wholly owned pipelines in 2007 was $487 million. Capital spending for the wholly owned pipelines in 2008 is expected to be approximately $1.0 billion. In addition, capital spending for TransCanada's 50 per cent share of constructing the Keystone pipeline is expected to be approximately $800 million.

NATURAL GAS THROUGHPUT VOLUMES

(Bcf)

	2007	2006	2005
Canadian Mainline[(1)]	**3,183**	2,955	2,997
Alberta System[(2)]	**4,015**	4,051	3,999
ANR[(3)]	**1,210**		
GTN System	**827**	790	777
Foothills[(4)]	**1,441**	1,403	1,372
North Baja	**90**	95	84
Great Lakes	**829**	816	850
Northern Border	**800**	799	808
Iroquois	**394**	384	394
TQM	**207**	158	166
Ventures LP	**178**	179	138
Gas Pacifico	**71**	52	34
Portland	**58**	52	62
Tamazunchale[(5)]	**29**	–	
Tuscarora	**28**	28	25
TransGas	**24**	22	19

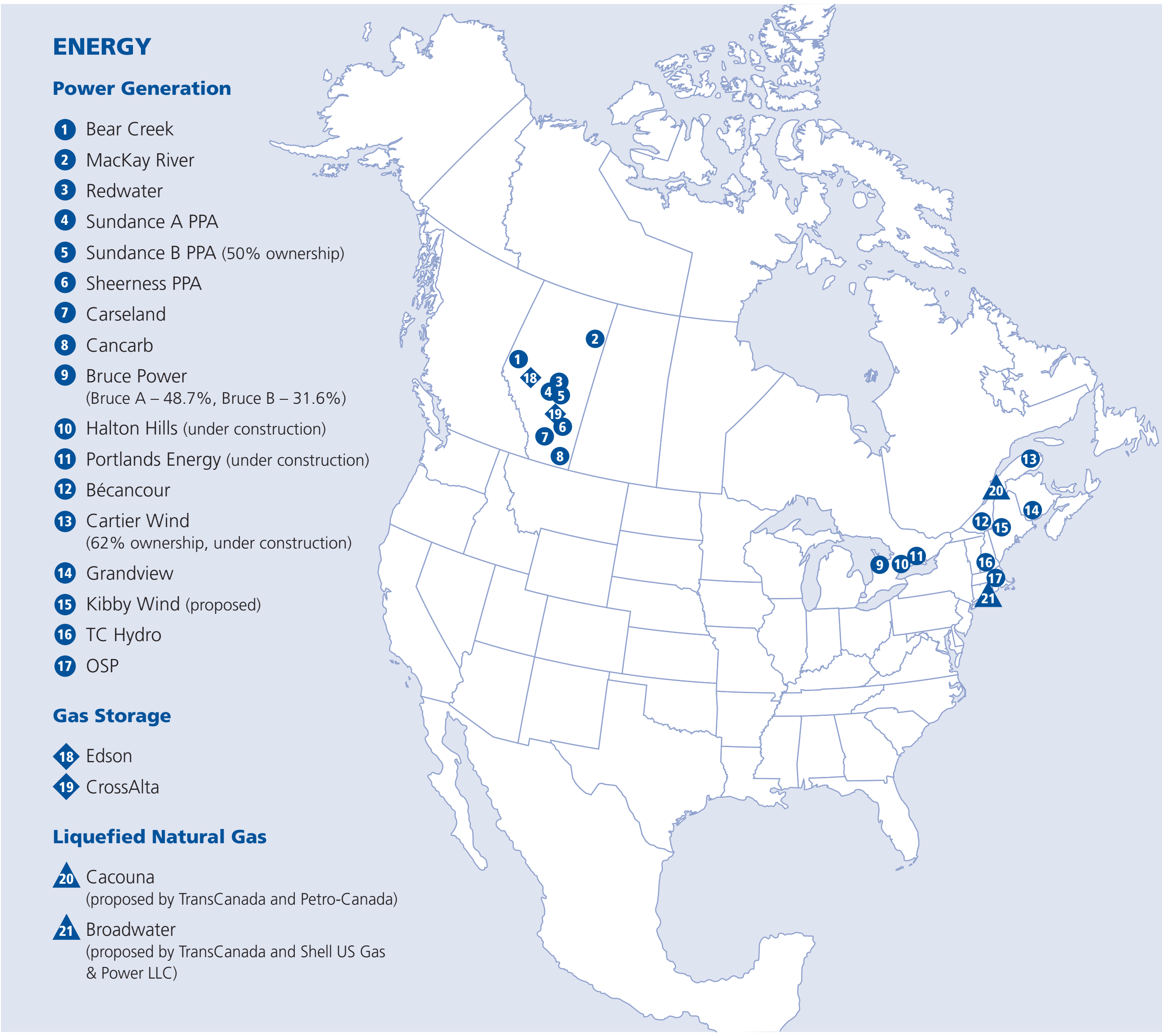
(1) Canadian Mainline deliveries originating at the Alberta border and in Saskatchewan in 2007 were 2,199 Bcf (2006 – 2,224 Bcf; 2005 – 2,215 Bcf).

(2) Field receipt volumes for the Alberta System in 2007 were 4,047 Bcf (2006 – 4,160 Bcf, 2005 – 4,034 Bcf).

(3) ANR was acquired February 22, 2007 and its volumes are included from this date.

(4) Foothills volumes reflects the combined operations of Foothills and the BC System.

(5) Tamazunchale's results include volumes since December 1, 2006.



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

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

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

SUNDANCE A&B The largest coal-fired electric power generating facility in Western Canada, Sundance is located in south-central Alberta. TransCanada has the rights to 100 per cent of the generating capacity of the 560-MW Sundance A facility under a power purchase arrangement (PPA), which 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, which expires in 2020.

SHEERNESS Consisting of two 390-MW coal-fired thermal power generating units, the Sheerness plant is located in southeastern Alberta. TransCanada has the rights to 756 MW of generating capacity from the Sheerness PPA, which expires in 2020.

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

CANCARB A 27-MW facility fuelled by waste heat from TransCanada's adjacent thermal carbon black facility, Cancarb is located in Medicine Hat, Alberta.

BRUCE POWER Consisting of two generating stations, Bruce A with approximately 3,000 MW of generating capacity and Bruce B with approximately 3,200 MW of generating capacity, Bruce Power is located in Ontario. TransCanada owns 48.7 per cent of Bruce A, which has four power generating units, two of which have been idled for refurbishing and are expected to restart in 2010. TransCanada owns 31.6 per cent of Bruce B, which also has four power generating units.

HALTON HILLS A 683-MW natural gas-fired power plant, Halton Hills is under construction near the town of Halton Hills, Ontario, and is expected to be in service in third-quarter 2010.

PORTLANDS ENERGY A 550-MW high-efficiency, combined-cycle natural gas generation power plant, Portlands Energy is under construction near downtown Toronto, Ontario. The plant is 50 per cent owned by TransCanada and is expected to be operational in simple-cycle mode, delivering 340 MW of electricity to the City of Toronto, beginning in June 2008. It is expected to be fully commissioned in its combined-cycle mode, delivering 550 MW of power, in second-quarter 2009.

BÉCANCOUR A 550-MW natural gas-fired cogeneration power plant, Bécancour is located near Trois-Rivières, Québec. The entire power output is supplied to Hydro-Québec under a 20-year power purchase contract. Steam is also sold to an industrial customer for use in commercial processes.

CARTIER WIND The 740-MW Cartier wind farm project consists of six wind power projects located in Québec. Cartier Wind is 62 per cent owned by TransCanada. Baie-des-Sables, with a generation capacity of 110 MW, and Anse-á-Valleau, with a generation capacity of 101 MW, were placed into service in November 2006 and November 2007, respectively. Construction of a third project, the 110-MW Carleton wind farm, began in late 2007. Planning and construction of the remaining three projects will continue, subject to future approvals.

GRANDVIEW A 90-MW natural gas-fired cogeneration power plant, Grandview is located in Saint John, New Brunswick. Irving Oil Limited receives 100 per cent of the plant's heat and electricity output under a 20-year tolling agreement.

KIBBY WIND A 132-MW wind power project, the proposed Kibby Wind includes 44 turbines located in Kibby and Skinner Townships in northwestern Franklin County, Maine. Subject to U.S. federal and state approvals, construction could begin in early 2008 and the new facilities could go into service in 2009–2010.

TC HYDRO With a total generating capacity of 583 MW, TC Hydro comprises 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, OSP is located in Rhode Island.

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

CROSSALTA An underground natural gas storage facility, CrossAlta is connected to the Alberta System and is located near Crossfield, Alberta. TransCanada owns 60 per cent of CrossAlta, which has a working natural gas capacity of 54 Bcf with a maximum deliverability capability of 480 mmcf/d.

CACOUNA A proposed LNG project at Gros Cacouna Harbour on the St. Lawrence River in Québec, Cacouna would be capable of receiving, storing and regasifying imported LNG with an average send-out capacity of approximately 500 mmcf/d of natural gas. TransCanada has a 50 per cent ownership interest in Cacouna.

BROADWATER A proposed offshore LNG project located in the New York waters of Long Island Sound, Broadwater would be capable of receiving, storing and regasifying imported LNG with an average send-out capacity of approximately 1 Bcf/d of natural gas. TransCanada has a 50 per cent ownership interest in Broadwater.

ENERGY – HIGHLIGHTS

Net Earnings

- Energy's net earnings were $514 million in 2007, an increase of $62 million from $452 million in 2006.
- Energy's comparable earnings were $466 million in 2007, up $37 million from $429 million in 2006. Comparable earnings excluded positive income tax adjustments in 2007 and 2006 and a gain on sale of land in 2007, and increased primarily due to higher operating income from Eastern Power and Natural Gas Storage.
- Results in 2007 included the first full year of earnings from the Bécancour cogeneration plant, the Baie-des-Sables Cartier Wind project, and the Edson natural gas storage facility.

Expanding Asset Base

- Approximately 2,000 MW of additional generation capacity was under construction at December 31, 2007, with an anticipated capital cost of more than $4.2 billion.
- Since 1999, TransCanada's Energy business has grown its nominal generating capacity by approximately 5,300 MW, excluding 2,000 MW currently under construction, representing an investment of more than $5 billion to the end of 2007.
- The Anse-á-Valleau Cartier Wind project was completed and placed into service in November 2007.
- Construction continued in 2007 on the Bruce A refurbishment and restart project, which includes restart of the currently idle power generating Units 1 and 2, and replacement of the steam generators and installation of new fuel channels on Units 3 and 4.

Plant Availability

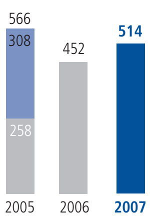
- Weighted average power plant availability was 91 per cent in 2007, which was consistent with 2006.
- Weighted average power plant availability, excluding Bruce, was 93 per cent in 2007, which was consistent with 2006.

ENERGY RESULTS-AT-A-GLANCE
Year ended December 31 *(millions of dollars)*

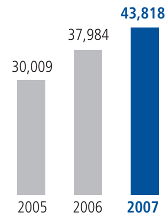
	2007	2006	2005
Western Power	**308**	297	123
Eastern Power	**255**	187	137
Bruce Power	**167**	235	195
Natural Gas Storage	**146**	93	32
Power LP Investment	**–**	–	29
General, administrative, support costs and other	**(158)**	(144)	(129)
Operating income	**718**	668	387
Financial charges	**(22)**	(23)	(11)
Interest income and other	**10**	5	5
Income taxes	**(240)**	(221)	(123)
Comparable earnings[(1)]	**466**	429	258
Income tax adjustments	**34**	23	–
Gain on sale of land	**14**	–	–
Gain on sale of Paiton Energy	**–**	–	193
Gain on sale of Power LP units	**–**	–	115
Net earnings	**514**	452	566

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

Energy Net Earnings (millions of dollars)



Power Sales Volumes (GWh)



Energy's net earnings in 2007 were $514 million compared to $452 million in 2006. Comparable earnings were $466 million in 2007, an increase of $37 million from 2006. Comparable earnings exclude the $14-million gain on sale of land and the $34-million favourable income tax adjustments in 2007 as well as the $23-million favourable impact in 2006 from future income taxes as a result of reductions in Canadian federal and provincial corporate income tax rates. The increase was due primarily to higher operating income in Eastern Power, Natural Gas Storage and Western Power, partially offset by a reduced contribution from Bruce Power.

Energy's net earnings in 2006 were $452 million compared to $566 million in 2005. The decrease was due primarily to the inclusion in 2005 net earnings of gains related to the disposal of TransCanada's investments in Paiton Energy and Power LP. In 2005, TransCanada sold its interest of approximately 11 per cent in Paiton Energy resulting in an after-tax gain of $115 million and sold its ownership interest in Power LP resulting in an after-tax gain of $193 million.

Energy's comparable earnings, which exclude the $23-million favourable impact on future income taxes in 2006 and the Power LP and Paiton Energy gains in 2005, were $429 million in 2006, an increase of $171 million from $258 million in 2005. The increase was due primarily to higher contributions from each of Energy's existing businesses, including a full year of earnings from TC Hydro, partially offset by the loss of operating income associated with the sale of the Power LP interest in 2005.

POWER PLANTS – NOMINAL GENERATING CAPACITY AND FUEL TYPE

	MW	Fuel Type
Western Power		
Sheerness(1)	756	Coal
Sundance A(2)	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
	2,061	
Eastern Power		
Halton Hills(3)	683	Natural gas
TC Hydro(4)	583	Hydro
OSP	560	Natural gas
Bécancour(5)	550	Natural gas
Cartier Wind(6)	458	Wind
Portlands Energy(7)	275	Natural gas
Grandview(8)	90	Natural gas
	3,199	
Bruce Power(9)	2,474	Nuclear
Total nominal generating capacity	7,734	

(1) TransCanada has sole access to 756 MW from Sheerness through a long-term PPA lease.

(2) TransCanada directly or indirectly has the rights to 560 MW from Sundance A and 353 MW from Sundance B through long-term PPAs, which represents 100 per cent of the Sundance A and 50 per cent of the Sundance B power plant output.

(3) Currently under construction.

(4) Acquired in second-quarter 2005.

(5) Placed in service in third-quarter 2006.

(6) Represents TransCanada's 62 per cent share of the total 740-MW project. Two of six wind farms were placed in service, one in November 2006 and the other in November 2007, with a combined generating capacity of 211 MW.

(7) Represents TransCanada's 50 per cent share of this 550-MW facility, which is currently under construction.

(8) Placed in service in first-quarter 2005.

(9) Represents TransCanada's 48.7 per cent proportionate interest in Bruce A and 31.6 per cent proportionate interest in Bruce B. Bruce A consists of four 750-MW reactors, two of which are currently being refurbished and are expected to restart in 2010. Bruce B consists of four reactors, which are currently in operation and have a combined capacity of approximately 3,200 MW.

ENERGY – FINANCIAL ANALYSIS

Western Power

As at December 31, 2007, Western Power owns or has the rights to approximately 2,100 MW of power supply in Alberta from its three long-term PPAs and five natural gas-fired cogeneration facilities. The power supply portfolio of Western Power 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 is among the lowest-cost, most competitive generation in the Alberta market area. On December 31, 2005, $585 million was paid to the Alberta Balancing Pool for the remaining rights of the Sheerness PPA, which has a remaining term of approximately 13 years. The Sundance A and B PPAs have remaining terms of 10 years and 13 years, respectively.

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 from the PPAs, markets uncommitted volumes from the cogeneration facilities, and purchases and resells power and gas to maximize the value of the cogeneration facilities. The marketing function is integral to optimizing Energy's return from its portfolio of power supply and to managing risks associated with uncontracted volumes. A portion of its power is sold into the spot market for operational reasons and the amount of supply volumes eventually sold into the spot market 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 its exposure to spot market prices on uncontracted volumes, Western Power had, as at December 31, 2007, fixed-price power sales contracts to sell approximately 9,200 gigawatt hours (GWh) in 2008 and 6,800 GWh in 2009.

Plant operations consist of five natural gas-fired cogeneration power plants located in Alberta with an approximate combined output capacity of 400 MW ranging from 27 MW to 165 MW per facility. A portion of the expected output is sold under long-term contracts and the remaining output is subject to fluctuations in the price of power and gas. Market heat rate is an economic measure for natural gas-fired power plants and is determined by dividing the average price of power per megawatt hour (MWh) by the average price of natural gas per gigajoule (GJ) for a given period. To the extent power is not sold under long-term contracts and plant fuel gas has not been purchased under long-term contracts, the profitability of a natural gas-fired generating facility rises in proportion to increases in the market heat rate, and, conversely, declines in proportion to decreases in the market heat rate. Market heat rates in Alberta decreased in 2007 by approximately 16 per cent as a result of a decrease in average power prices, while spot market natural gas prices remained relatively unchanged. Market heat rates averaged approximately 11.4 GJ/MWh in 2007 compared to approximately 13.5 GJ/MWh in 2006.

All plants in Western Power operated with an average plant availability of approximately 90 per cent in 2007 compared to 88 per cent in 2006.

Western Power Results-at-a-Glance
Year ended December 31 *(millions of dollars)*

	2007	2006	2005
Revenues			
Power	**1,045**	1,185	715
Other[1]	**89**	169	158
	1,134	1,354	873
Commodity purchases resold			
Power	**(608)**	(767)	(476)
Other[2]	**(65)**	(135)	(104)
	(673)	(902)	(580)
Plant operating costs and other	**(135)**	(135)	(149)
Depreciation	**(18)**	(20)	(21)
Operating income	**308**	297	123

(1) Includes natural gas sold and Cancarb Thermax, the thermal carbon black facility adjacent to Cancarb.

(2) Includes the cost of natural gas sold.

Western Power Sales Volumes
Year ended December 31 *(GWh)*

	2007	2006	2005
Supply			
Generation	**2,154**	2,259	2,245
Purchased			
Sundance A & B and Sheerness PPAs	**12,199**	12,712	6,974
Other purchases	**1,433**	1,905	2,687
	15,786	16,876	11,906
Contracted vs. Spot			
Contracted	**11,998**	12,750	10,374
Spot	**3,788**	4,126	1,532
	15,786	16,876	11,906

Operating income was $308 million in 2007, an increase of $11 million from $297 million in 2006. The increase was due primarily to lower PPA costs, partially offset by slightly lower overall realized power prices. Revenues decreased in 2007 compared to 2006 due mainly to the lower overall power sales prices realized in 2007 as well as lower volumes purchased and generated. Commodity purchases resold decreased in 2007 compared to 2006 due primarily to lower PPA costs, a decrease in volumes purchased and the expiry of certain retail contracts. Purchased power volumes in 2007 decreased compared to 2006 mainly as a result of an increase in outage hours at the Sundance A facility and the expiry of certain retail contracts. Approximately 24 per cent of power sales volumes were sold in to the spot market in 2007, which was consistent with 2006.

Operating income was $297 million in 2006, an increase of $174 million from $123 million in 2005. The increase was due primarily to incremental earnings from the acquisition of the Sheerness PPA on December 31, 2005, and increased margins from a combination of higher overall realized power prices and higher market heat rates on uncontracted volumes of power sold. Revenues and commodity purchases resold increased in 2006 compared to 2005 due mainly to the acquisition of the Sheerness PPA as well as higher realized power prices. Plant operating costs and other, which includes fuel gas consumed in power generation, decreased due to lower natural gas prices. Purchased power volumes in 2006 increased compared to 2005 due primarily to the acquisition of the Sheerness PPA. Approximately 24 per cent of power sales volumes were sold into the spot market in 2006 compared to 13 per cent in 2005.

Eastern Power

Eastern Power owns approximately 3,200 MW of power generation capacity, including facilities under construction or in the development phase. Eastern Power's current operating power generation assets are TC Hydro, Ocean State Power (OSP), Bécancour and Grandview, and the Baie-des-Sables and Anse-á-Valleau wind farms. The TC Hydro assets include 13 hydroelectric stations housing 39 hydroelectric generating units in New Hampshire, Vermont and Massachusetts.

Eastern Power conducts its business primarily in the deregulated New England power market and in Eastern Canada. In the New England market, TransCanada has established a successful marketing operation through its wholly owned subsidiary, TransCanada Power Marketing Ltd. (TCPM), located in Westborough, Massachusetts. To reduce exposure to spot market prices on uncontracted volumes, Eastern Power had, as at December 31, 2007, fixed price sales contracts to sell forward approximately 8,200 GWh in 2008 and 9,900 GWh in 2009. Fixed price sales contracts in 2008 exclude approximately 4,200 GWh of generation from the Bécancour power plant as a result of the request from Hydro-Québec to suspend electricity generation, beginning January 1, 2008.

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. In 2007, TCPM continued to expand its marketing presence and customer base.

In June 2006, the FERC approved a settlement agreement to implement a newly-designed Forward Capacity Market (FCM) for power generation in the New England power markets. The FCM design is intended to promote investment in new and existing power resources needed to meet growing consumer demand and maintain a reliable power system. The settlement agreement provides for a multi-year transition period beginning in December 2006 and ending in May 2010, whereby fixed payments ranging from US$3.05 to US$4.10 per kilowatt-month, will be made to owners of existing installed capacity. Eastern Power's OSP plant and TC Hydro generation facilities are eligible to receive payments during the transition period. Under the new FCM design, Independent System Operator New England will project the needs of the power system three years in advance, following which it will hold an annual auction to purchase power resources to satisfy a region's future needs. Suppliers will receive payments pursuant to the FCM auction mechanism commencing June 1, 2010.

Eastern Power Results-at-a-Glance[1]
Year ended December 31 *(millions of dollars)*

	2007	2006	2005
Revenues			
Power	**1,481**	789	505
Other[2]	**239**	292	412
	1,720	1,081	917
Commodity purchases resold			
Power	**(755)**	(379)	(215)
Other[2]	**(208)**	(257)	(373)
	(963)	(636)	(588)
Plant operating costs and other	**(454)**	(226)	(167)
Depreciation	**(48)**	(32)	(25)
Operating income	**255**	187	137

(1) Includes Bécancour, Baie-des-Sables and Anse-à-Valleau, effective September 17, 2006, November 21, 2006 and November 10, 2007, respectively.

(2) Other includes natural gas sales and purchases.

Eastern Power Sales Volumes[1]
Year ended December 31 *(GWh)*

	2007	2006	2005
Supply			
Generation	**8,095**	4,700	2,879
Purchased	**6,986**	3,091	2,627
	15,081	7,791	5,506
Contracted vs. Spot			
Contracted	**14,505**	7,374	4,919
Spot	**576**	417	587
	15,081	7,791	5,506

(1) Includes Bécancour, Baie-des-Sables and Anse-à-Valleau, effective September 17, 2006, November 21, 2006 and November 10, 2007, respectively.

Operating income was $255 million in 2007, $68 million higher than the $187 million earned in 2006. The increase was due primarily to incremental income from the first full year of operation of the Bécancour facility and the Baie-des-Sables wind farm, and from the start-up of the Anse-à-Valleau wind farm in November 2007. Also contributing to the increase were payments received under the start-up of the FCM in New England and higher sales volumes to commercial and industrial customers in 2007. Partially offsetting these increases was the impact of reduced water flows from the TC Hydro generation assets in 2007, compared to the above-average water flows experienced in 2006 following higher precipitation in the surrounding area.

Eastern Power's revenues from power were $1,481 million in 2007, an increase of $692 million from $789 million in 2006. The substantial growth was driven primarily by the first full year of revenue from the Bécancour facility and the

Baie-des-Sables wind farm, which went into service in September and November 2006, respectively, as well as by increased sales volumes to commercial and industrial customers, and higher realized prices. Other revenue and other commodity purchases resold decreased year-over-year as a result of a reduction in the quantity of natural gas purchased and resold under OSP's natural gas supply contracts. Power commodity purchases resold and purchased power volumes were higher in 2007 due to the impact of increased purchases to supply higher sales volumes to wholesale, commercial and industrial customers. The increase in purchased power volumes was partially offset by additional power generation from the OSP plant, which reduced the requirement to purchase power to fulfill contractual sales obligations. Plant operating costs and other, which includes fuel gas consumed in generation, were higher in 2007 due primarily to the full year of operations of the Bécancour facility and increased power generation from the OSP plant.

Operating income was $187 million in 2006, an increase of $50 million from $137 million earned in 2005. The increase was due mainly to incremental income from the full year of ownership of the TC Hydro assets, the start-up of the Bécancour facility, a $10-million after-tax one-time restructuring payment in first-quarter 2005 from OSP to its natural gas fuel suppliers, and higher overall margins on power sales volumes in 2006.

Bruce Power

In 2005, Bruce Power and the Ontario Power Authority (OPA) completed a long-term agreement whereby Bruce A committed to refurbish and restart the currently idle Units 1 and 2, extend the operating life of Unit 3 by replacing its steam generators and fuel channels when required, and replace the steam generators on Unit 4. An amendment to this agreement in 2007 is described further in the "Energy – Opportunities and Developments" section of this MD&A. As a result of an agreement between Bruce Power and the OPA, and Cameco Corporation's (Cameco) decision not to participate in the refurbishment and restart program, the Bruce A partnership was formed by TransCanada and BPC Generation Infrastructure Trust (BPC), with each owning a 48.7 per cent interest in Bruce A at December 31, 2007 (2006 – 48.7 per cent; 2005 – 47.9 per cent). TransCanada and BPC each incurred a net cash outlay of approximately $100 million in 2005 to acquire Cameco's interest. The remaining 2.6 per cent interest in Bruce A is owned by BPC, a trust established by the Ontario Municipal Employees Retirement System, the Power Worker's Union and The Society of Energy Professionals. The Bruce A partnership subleases Bruce A Units 1 to 4 from Bruce B. TransCanada continues to own 31.6 per cent of Bruce B, which consists of Units 5 to 8.

Upon reorganization, both Bruce A and Bruce B became jointly controlled entities and TransCanada proportionately consolidated these investments on a prospective basis from October 31, 2005. The following Bruce Power financial results reflect the operations of six of the eight Bruce Power units in all periods.

Bruce Power Results-at-a-Glance Year ended December 31 *(millions of dollars)*	**2007**	2006	2005
Bruce Power (100 per cent basis)			
Revenues			
Power	**1,920**	1,861	1,907
Other(1)	**113**	71	35
	2,033	1,932	1,942
Operating expenses			
Operations and maintenance(2)	**(1,051)**	(912)	(871)
Fuel	**(104)**	(96)	(77)
Supplemental rent(2)	**(170)**	(170)	(164)
Depreciation and amortization	**(151)**	(134)	(198)
	(1,476)	(1,312)	(1,310)
Revenues, net of operating expenses	**557**	620	632
Financial charges under equity accounting(3)	**–**	–	(58)
	557	620	574
TransCanada's proportionate share – Bruce A	**24**	91	22
TransCanada's proportionate share – Bruce B	**161**	137	166
TransCanada's proportionate share	**185**	228	188
Adjustments	**(18)**	7	7
TransCanada's operating income from Bruce Power(3)	**167**	235	195
Bruce Power – Other Information			
Plant availability			
Bruce A	**78%**	81%	94%
Bruce B	**89%**	91%	79%
Combined Bruce Power	**86%**	88%	80%
Planned outage days			
Bruce A	**121**	81	106
Bruce B	**93**	65	153
Unplanned outage days			
Bruce A	**17**	37	30
Bruce B	**32**	31	104
Sales volumes (GWh)			
Bruce A – 100 per cent	**10,180**	10,650	2,100
Bruce A – TransCanada's proportionate share	**4,959**	5,158	999
Bruce B – 100 per cent	**25,290**	25,820	30,800
Bruce B – TransCanada's proportionate share	**7,992**	8,159	9,733
Combined Bruce Power – 100 per cent	**35,470**	36,470	32,900
TransCanada's proportionate share	**12,951**	13,317	10,732
Results per MWh			
Bruce A power revenues	**$59**	$58	$57
Bruce B power revenues	**$52**	$48	$58
Combined Bruce Power revenues	**$55**	$51	$58
Combined Bruce Power fuel	**$3**	$3	$2
Combined Bruce Power total operating expenses(4)	**$41**	$35	$40
Percentage of output sold to spot market	**45%**	35%	49%

(1) Includes fuel cost recoveries of $35 million for Bruce A in 2007 (2006 – $30 million; November 1 to December 31, 2005 – $4 million). Includes changes in fair value of held-for-trading derivatives of $47 million in 2007 (2006 – nil; 2005 – nil).

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

(3) TransCanada's consolidated equity income in 2005 includes $168 million which represents TransCanada's 31.6 per cent share of Bruce Power earnings for the ten months ended October 31, 2005.

(4) Net of fuel cost recoveries.

TransCanada's operating income from its investment in Bruce Power was $167 million in 2007 compared to $235 million in 2006. TransCanada's proportionate share of operating income in Bruce B increased $24 million to $161 million in 2007 compared with 2006 due primarily to higher realized power prices, partially offset by higher operating costs associated with an increase in planned outage days in 2007. TransCanada's proportionate share of operating income in Bruce A decreased $67 million to $24 million in 2007 compared with 2006 due primarily to lower output and higher operating costs associated with an increase in planned outage days in 2007. Higher post-employment benefit costs and lower positive purchase price amortizations related to the expiry of power sales agreements also contributed to the decrease in TransCanada's operating income from its combined investment in Bruce power in 2007 compared to 2006.

Combined Bruce Power prices (excluding other revenues) were $55 per MWh in 2007 compared to $51 per MWh in 2006, reflecting higher prices on both contracted volumes and uncontracted volumes sold into the spot market. Bruce Power's combined operating expenses (net of fuel cost recoveries) increased to $41 per MWh in 2007 from $35 per MWh in 2006 due primarily to higher operating costs and decreased output in 2007.

The Bruce units ran at a combined average availability of 86 per cent in 2007, compared to an 88 per cent average availability in 2006. The lower availability in 2007 was the result of more planned maintenance outage days, partially offset by fewer unplanned outage days in 2007.

TransCanada's operating income from its combined investment in Bruce Power was $235 million in 2006 compared to $195 million in 2005. The increase of $40 million was due primarily to an increased ownership interest in the Bruce A facilities and higher sales volumes resulting from increased plant availability, partially offset by lower overall realized prices.

Adjustments to TransCanada's combined interest in Bruce Power's income before income taxes were lower in 2007 than in 2006 and 2005 due primarily to lower positive purchase price amortizations related to the expiry of power sales agreements.

Income from Bruce B is directly affected by fluctuations in wholesale spot market prices for electricity. Income from both Bruce A and Bruce B is affected by overall plant availability, which in turn is affected by planned and unplanned maintenance. As a result of a contract with the OPA, all of the output from Bruce A is sold at a fixed price per MWh, adjusted for inflation annually on April 1, and before recovery of fuel costs from the OPA. Per the 2007 amendment of the contract with the OPA, discussed in the "Energy – Opportunities and Developments" section, effective April 1, 2008, the fixed price for output from Bruce A will also increase by $2.11 per MWh, subject to inflation adjustments from October 31, 2005.

	per MWh
April 1, 2007 – March 31, 2008	$59.69
April 1, 2006 – March 31, 2007	$58.63
October 31, 2005 – March 31, 2006	$57.37

Payments received pursuant to the fixed-price contract are capped at $575 million for the period ending on the commercial in-service date of the later of the restarted Unit 1 and Unit 2. Post-refurbishment prices will also be adjusted for capital cost variances associated with the refurbishment and restart projects.

As part of this contract, sales from the Bruce B Units 5 to 8 are subject to a floor price adjusted annually for inflation on April 1.

	per MWh
April 1, 2007 – March 31, 2008	$46.82
April 1, 2006 – March 31, 2007	$45.99
October 31, 2005 – March 31, 2006	$45.00

Payments received pursuant to the Bruce B floor price mechanism may be subject to a recapture payment dependent on annual spot prices over the term of the contract. Bruce B net earnings to date do not include any amounts received pursuant to this floor mechanism. To further reduce its exposure to spot market prices, Bruce B entered into fixed price sales contracts as at December 31, 2007, to sell forward approximately 10,200 GWh in 2008 and 4,900 GWh in 2009.

The overall plant availability percentage in 2008 is expected to be in the low 90s for the four Bruce B units and the low 80s for the two operating Bruce A units. A planned maintenance outage of Bruce B Unit 7 began at the end of January 2008 and the unit is expected to be back in service in March 2008. A planned maintenance outage of Bruce B Unit 5 is scheduled to begin in early May 2008 and the unit is expected to return to service in late second-quarter 2008. A one-month maintenance outage of Bruce A Unit 4 is scheduled to start in late March 2008 and a two-month outage of Bruce A Unit 3 is expected to commence mid-September 2008.

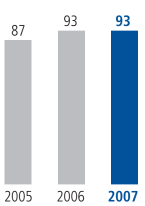
The Bruce partners have agreed that all excess cash from both Bruce A and Bruce B will be distributed on a monthly basis and that separate cash calls will be made for major capital projects, including the Bruce A refurbishment and restart project.

Power LP Divestiture

TransCanada sold all of its interest in Power LP to EPCOR Utilities Inc. in August 2005 for net proceeds of $523 million, resulting in an after-tax gain of $193 million. TransCanada's investment in Power LP generated operating income of $29 million in 2005.

Plant Availability

Power Plant Availability (excluding Bruce Power)
(per cent)



Weighted average power plant availability for all plants, excluding Bruce Power, was 93 per cent in 2007 and 2006, compared to 87 per cent in 2005. Plant availability represents the percentage of time in a year that the plant is available to generate power whether actually running or not, reduced by planned and unplanned outages. Western Power's plant availability was affected negatively in 2006 and 2005 by an unplanned outage at Bear Creek, which returned to service in August 2006. A planned outage was taken in 2005 at the MacKay River facility, further decreasing Western Power's plant availability in 2005. Eastern Power achieved plant availability of 96 per cent in 2007, which was consistent with 2006. Availability was lower in 2005 as a result of OSP experiencing two significant outages.

Weighted Average Plant Availability[1]
Year ended December 31

	2007	2006	2005
Western Power[2]	**90%**	88%	85%
Eastern Power[3]	**96%**	95%	83%
Bruce Power	**86%**	88%	80%
Power LP investment[4]	**–**	–	94%
All plants, excluding Bruce Power investment	**93%**	93%	87%
All plants	**91%**	91%	84%

(1) Plant availability represents the percentage of time in a year that the plant is available to generate power, whether actually running or not, reduced by planned and unplanned outages.

(2) The Sheerness PPA is included in Western Power, effective December 31, 2005.

(3) TC Hydro, Bécancour, Baie-des-Sables and Anse-á-Valleau are included in Eastern Power effective April 1, 2005, September 17, 2006, November 21, 2006 and November 10, 2007, respectively.

(4) Power LP is included to August 31, 2005.

Natural Gas Storage

TransCanada became one of the largest natural gas storage providers in Western Canada when the Edson storage facility was placed in service on December 31, 2006, with a final commissioning date of April 1, 2007. TransCanada owns or has rights to 120 Bcf of natural gas storage capacity in Alberta, including a 60 per cent ownership interest in CrossAlta Gas Storage & Services Ltd. (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 and include mutual 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)	32	288
Third-party storage	38	630
	120	1,643

(1) Represents TransCanada's 60 per cent ownership interest in CrossAlta, a 54-Bcf, 480-mmcf/d facility.

TransCanada believes the market fundamentals for natural gas storage remain strong. The Company's additional gas storage capacity is expected to help balance seasonal and short-term supply and demand, and bring flexibility to the supply of natural gas to 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 should northern gas be connected to North American markets. Energy's natural gas storage business operates independently from TransCanada's regulated natural gas transmission business and ANR's regulated storage business, which is included in TransCanada's Pipelines segment.

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

In Alberta, TransCanada offers a broad range of injection and withdrawal storage alternatives specific to customer needs in multi-year contracts. Market volatility frequently creates arbitrage opportunities and TransCanada's storage operations offer solutions to capture value from these short-term price movements. Products consist of short-term deliver-redeliver contracts, parking, peak-day supply and other related services. Earnings from third-party storage capacity leases are recognized over the term of the lease. At December 31, 2007, TransCanada had contracted approximately 74 per cent of the total 120 Bcf of working gas storage capacity in 2008 and 50 per cent of storage capacity in 2009.

TransCanada adopted an accounting policy to record proprietary natural gas inventory held in storage at its fair value using the one-month forward price for natural gas, effective April 1, 2007. Changes in the fair value of inventory are recorded in Net Income.

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 a margin, thereby effectively eliminating its exposure to the price movements of natural gas. 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 values based on the forward market prices for the contracted month of delivery. Changes in the fair value of these contracts are recorded in Net Income. In 2007, operating income included a $10-million net unrealized gain for the changes in fair value of the proprietary natural gas inventory and forward purchase and sales contracts.

Natural Gas Storage operating income was $146 million in 2007, an increase of $53 million compared to 2006. The increase was due primarily to income earned from the first full year of operations of the Edson facility.

Natural Gas Storage operating income was $93 million in 2006, an increase of $61 million compared to 2005. The increase was due primarily to higher contributions from CrossAlta as a result of increased utilization and higher natural gas storage spreads as well as income from contracted third-party natural gas storage capacity. The Edson facility did not contribute to earnings in 2006 as it went into service on December 31, 2006.

ENERGY – OPPORTUNITIES AND DEVELOPMENTS

Portlands Energy Construction continued in 2007 on the Portlands Energy Centre L.P. (Portlands Energy) project. The capital cost is expected to be approximately $730 million and the facility is expected to be operational in single-cycle mode beginning June 2008. Upon final completion of the combined-cycle mode planned for second-quarter 2009, the plant is expected to provide power under a 20-year Accelerated Clean Energy Supply contract with the OPA.

Halton Hills Site preparation and construction began in 2007 on the Halton Hills Generating Station (Halton Hills). The project includes the construction and operation of a natural gas-fired power plant near the town of Halton Hills, Ontario. TransCanada expects to invest approximately $670 million in the project, which is anticipated to be in service in third-quarter 2010. Power from the facility will be sold to the OPA under a 20-year Clean Energy Supply contract.

Cartier Wind The Anse-à-Valleau wind farm went into commercial operation in November 2007, providing up to 101 MW of power to the Hydro Québec grid, and construction began in 2007 on the Carleton wind farm with a generation capacity of 110 MW. Carleton is expected to enter commercial service in fourth-quarter 2008. Anse-à-Valleau and Carleton are the second and third phases, respectively, of the six-phase, multi-year Cartier Wind project, located in the Gaspé region of Québec. The first phase, Baie-des-Sables, went into service in November 2006, generating up to 110 MW of power. The remaining phases of Cartier Wind are expected to be constructed through 2012, subject to the necessary approvals. Capacity is expected to total 740 MW when all six phases are complete.

Kibby Wind In January 2008, Maine's Land Use Regulation Commission voted to recommend the approval of the zoning changes and preliminary development plan submitted by TransCanada to build, own and operate a wind farm in Maine. Subject to U.S. federal and state approvals, construction of the new facilities could begin in 2008, with the project being commissioned in 2009-2010.

Bécancour TransCanada entered into an agreement with Hydro-Québec in November 2007 to temporarily suspend all electricity generation from the Bécancour power plant during 2008. The agreement, which was requested by Hydro-Québec as a result of its excess electricity supply, was approved by Québec's Régie de l'énergie in December 2007. The agreement also provides Hydro-Québec the option to extend the suspension to 2009. TransCanada will receive payments under the agreement similar to those that would have been received under the normal course of operation.

Bruce Power Bruce Power and the OPA amended their Bruce A refurbishment agreement in 2007 to allow for the installation of 480 new fuel channels in Unit 4. Under the original plan, Bruce Power intended to install new steam generators in all four Bruce A units and replace the fuel channels in Units 1, 2 and 3. By replacing the fuel channels in Unit 4, Bruce Power will extend the expected operational life of the unit to 2036 from 2017. Under the amended agreement, the OPA may elect prior to April 1, 2008 to proceed with a three-unit refurbishment and restart program.

The amended refurbishment capital program was originally expected to cost $5.25 billion with $2.75 billion being attributed to refurbishing and restarting Units 1 and 2 and $2.5 billion being attributed to refurbishing Units 3 and 4. In January 2008, a milestone in the Bruce A Units 1 and 2 refurbishment and restart project was completed when the sixteenth and final new steam generator was installed. With the completion of this stage of the project, the authorized funding for Units 1 and 2 was increased to approximately $3.0 billion from $2.75 billion. Bruce Power is currently preparing a comprehensive estimate of the cost to complete the Unit 1 and 2 restart. This process is expected to result in a further increase in the total project cost. Project cost increases are subject to the capital cost risk- and reward-sharing mechanism under the agreement with the OPA. Bruce A Units 1 and 2 are expected to produce an additional 1,500 MW of power when completed in 2010.

As at December 31, 2007, Bruce A had incurred $1.9 billion in costs with respect to the refurbishment and restart of Units 1 and 2 and approximately $0.2 billion for the refurbishment of Units 3 and 4.

LNG Projects
TransCanada continues to pursue proposals to build, own and operate LNG facilities, including the Broadwater LNG project (Broadwater) and the Cacouna LNG project (Cacouna).

Broadwater Broadwater, a joint venture with Shell US Gas & Power LLC in which TransCanada holds a 50 per cent interest, is a proposed LNG facility in New York State waters in Long Island Sound. The Broadwater terminal would be capable of receiving, storing, and regasifying imported LNG with an average send-out capacity of approximately 1 Bcf/d of natural gas. Coincident with the FERC process, Broadwater applied to the New York Department of State for a determination that the project is consistent with New York's coastal zone policies. The state's decision is expected in second-quarter 2008. In January 2008, the FERC issued the FEIS, which confirmed project need, supported the location of the project with acknowledgement of its target market and delivery goals, and found safety and security risks to be limited and acceptable. The FEIS also concluded that with adherence to federal and state permit requirements and regulations, Broadwater's proposed mitigation measures and the FERC's recommendations, the project will not result in a significant impact on the environment. At December 31, 2007, the Company had capitalized $40 million related to Broadwater.

Cacouna Cacouna, a joint venture with Petro-Canada in which TransCanada holds a 50 per cent interest, is a proposed LNG project at the Gros Cacouna Harbour on the St. Lawrence River in Québec. The proposed terminal would be capable of receiving, storing, and regasifying imported LNG with an average throughput capacity of approximately 500 mmcf/d of natural gas. Following public hearings in 2006, the Québec government granted a provincial decree in June 2007 approving the Cacouna terminal. Also in June 2007, the project received federal approvals pursuant to the *Canadian Environmental Assessment Act*. A delay to 2012 from 2010 in the planned in-service date for the regasification terminal was announced in September 2007. This delay resulted from a need to assess the impacts of permit conditions, to review the facility design in light of escalating costs and to align the schedule with potential LNG supply facilities. In February 2008, the potential anchor LNG supplier for the Cacouna terminal announced it would no longer be pursuing the development of its LNG supply as originally planned. As a result of this announcement, TransCanada and Petro-Canada are currently reviewing their strategy for the 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 market forces such as fluctuating supply and demand, which are greatly affected by weather events. 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.

Uncontracted Volumes
Energy has certain uncontracted power sales volumes in Western Power and Eastern Power and through its investment in Bruce Power. Sale of uncontracted power volumes into the spot market is subject to market price volatility, which directly impacts earnings. Bruce B has a significant amount of uncontracted volumes sold into the wholesale power spot market while 100 per cent of the Bruce A output is sold into the Ontario wholesale power spot market under fixed contract price terms with the OPA. The 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 commitments containing varying 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 and the duration of outages could result in lower plant output and sales revenue, reduced 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 demand for power and natural gas. These same 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 the Cartier Wind assets in Québec.

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 and Capital Cost

Energy's new construction programs in Ontario and Québec, including its investment in Bruce Power, are subject to execution and capital cost risks. At Bruce Power, Bruce A's four unit refurbishment and restart project is also subject to a capital cost risk- and reward-sharing mechanism with the OPA.

Asset Commissioning

Although all of TransCanada's newly constructed assets go 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.

Power Regulatory

TransCanada operates in both regulated and deregulated power markets. As electricity markets evolve across North America, there is the potential for regulatory bodies to implement new rules that could negatively impact 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 or attempts to control the wholesale market by encouraging new plant construction. TransCanada continues to monitor regulatory issues and regulatory reform and participate in and lead discussions around these topics.

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

ENERGY – OUTLOOK

Although TransCanada has sold forward significant output from its Alberta PPAs and power plants and capacity from its natural gas storage facilities, operating income in 2008 can be affected by changes in the spot market price of power, market heat rates, hydrology, natural gas storage spreads and unplanned outages. Operating income from Energy's foreign operations is impacted by changes in foreign currency exchange rates. TransCanada's operating income from its investment in Bruce B can be significantly affected by the impact on uncontracted output of changes in spot market prices for power. Bruce Power's operating income is expected to be impacted by higher projected generation volumes and lower outage costs resulting from a decrease in planned outages in 2008 compared to 2007.

Other factors such as plant availability, regulatory changes, weather, currency movements, and overall stability of the energy industry can also impact 2008 operating income. Refer to the "Energy – Business Risks" section of this MD&A for a complete discussion of these factors.

Capital Expenditures
Total capital expenditures for Energy in 2007 were $1.1 billlion. Energy's overall capital spending in 2008 is expected to be approximately $1.1 billion and includes cash calls for the Bruce A refurbishment and restart project as well as continued construction at Halton Hills, Portlands Energy and Cartier Wind.

CORPORATE

CORPORATE RESULTS-AT-A-GLANCE
Year ended December 31 *(millions of dollars)*

	2007	2006	2005
Indirect financial charges and non-controlling interests	**248**	136	130
Interest income and other	**(83)**	(31)	(29)
Income taxes	**(120)**	(72)	(65)
Comparable expenses[1]	**45**	33	36
Income tax reassessments and adjustments	**(68)**	(72)	–
Net (earnings)/expenses, after income taxes	**(23)**	(39)	36

[1] Refer to the "Non-GAAP Measures" section of this MD&A for further discussion of comparable earnings.

Corporate reflects net expenses not allocated to specific business segments, including:

- *Indirect Financial Charges and Non-Controlling Interests* Direct financial charges are reported in their respective business segments and are associated primarily with debt and preferred securities related to the Company's wholly owned natural gas pipelines. Indirect financial charges, including the related foreign exchange impacts, reside mainly in Corporate. These costs are influenced directly by the amount of debt that TransCanada maintains and the degree to which the Company is affected by fluctuations in interest and foreign exchange rates.
- *Interest Income and Other* Interest income includes interest earned on invested cash balances and income tax refunds. Gains and losses on foreign exchange related to hedges of the Company's U.S.-dollar net income and of working capital are also included in Interest Income and Other.
- *Income Taxes* Income tax recoveries includes income taxes calculated on Corporate's net expenses as well as income tax refunds, reassessments and adjustments that have not been excluded for comparable earnings purposes.

CORPORATE – FINANCIAL RESULTS

Net earnings in Corporate were $23 million in 2007 compared to net earnings of $39 million in 2006 and net expenses of $36 million in 2005.

Corporate's net earnings included favourable income tax reassessments and adjustments of $68 million and $72 million in 2007 and 2006, respectively. Excluding these income tax adjustments, Corporate had comparable expenses of $45 million in 2007, an increase of $12 million from comparable expenses of $33 million in 2006. Gains on derivatives used to manage the Company's exposure to foreign exchange rate fluctuations and the impact of positive tax rate differentials were more than offset by higher financial charges resulting primarily from financing the acquisitions of ANR and additional interest in Great Lakes.

The increase in Corporate's net earnings in 2006 compared with 2005 was due mainly to the $72 million of favourable income tax legislative changes, reassessments and adjustments and the positive impact of the weaker U.S. dollar.

CORPORATE – OUTLOOK

Corporate's net expenses in 2007 included certain favourable income tax reassessments and adjustments that are not expected to recur in 2008. Financing costs associated with debt issued in 2007 and new debt expected to be issued in 2008 to partially finance the Company's capital programs are expected to increase net expenses in Corporate in 2008, which will be partially offset by capitalized interest for projects under construction. Corporate's results could also be affected by debt levels, interest rates, foreign exchange and income tax refunds and adjustments. The performance of the Canadian dollar relative to the U.S. dollar will influence Corporate's results, although this impact is mitigated by offsetting U.S.-dollar exposures in certain of TransCanada's other businesses and by the Company's hedging activities.

DISCONTINUED OPERATIONS

TransCanada did not have income from discontinued operations in 2007 and 2005. Income from discontinued operations was $28 million in 2006, reflecting bankruptcy settlements with Mirant related to TransCanada's Gas Marketing business, which the Company divested in 2001.

LIQUIDITY AND CAPITAL RESOURCES

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

	2007	2006	2005
Funds generated from operations	**2,621**	2,378	1,951
Decrease/(increase) in operating working capital	**215**	(303)	(49)
Net cash provided by operations	**2,836**	2,075	1,902

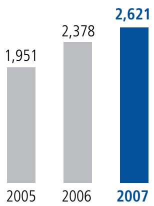
HIGHLIGHTS

Investing Activities
- Capital expenditures and acquisitions, including assumed debt, totalled approximately $11.0 billion over the three-year period ending December 31, 2007.

Dividend
- TransCanada's Board of Directors declared a $0.36 per common share dividend for the quarter ending March 31, 2008, an increase of six per cent over the previous dividend amount.

Funds Generated from Operations

Funds Generated from Operations (millions of dollars)



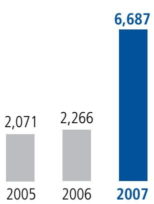
Funds Generated from Operations were $2.6 billion in 2007 compared to $2.4 billion and $2.0 billion, in 2006 and 2005, respectively. The increase in 2007 compared to 2006 was mainly a result of higher earnings. The Pipelines business was the primary source of the increase in Funds Generated from Operations in each of the three years. Growth in Energy's operations also caused an increase in Funds Generated from Operations in 2007 compared to the two prior years.

At December 31, 2007, TransCanada's ability to generate adequate amounts of cash in the short term and the long term when needed and to maintain financial capacity and flexibility to provide for planned growth was consistent with recent years.

Investing Activities

Capital expenditures totalled $1,651 million in 2007 compared to $1,572 million in 2006 and $754 million in 2005. Expenditures in 2007 were related primarily to construction of new power plants in Canada, the development of new pipelines, including Keystone, and maintenance and capacity projects in the Pipelines business in Canada and the U.S. Expenditures in 2006 and 2005 were related primarily to construction of new power plants and natural gas storage facilities in Canada and maintenance and capacity projects in the Pipelines business.

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



TransCanada acquired, from El Paso Corporation, 100 per cent of ANR and an additional 3.6 per cent interest in Great Lakes for US$3.4 billion in 2007, subject to certain post-closing adjustments, including approximately US$491 million of assumed long-term debt. The additional interest in Great Lakes increased TransCanada's ownership to 53.6 per cent. PipeLines LP acquired, from El Paso Corporation, the remaining 46.4 per cent of Great Lakes for US$942 million, subject to certain post-closing adjustments, including US$209 million of assumed long-term debt.

In December 2007, PipeLines LP purchased, from Sierra Pacific Resources, a one per cent ownership interest in Tuscarora for approximately $2 million. In a separate transaction, PipeLines LP also purchased TransCanada's one per cent ownership interest in Tuscarora for approximately $2 million. As a result of these transactions, PipeLines LP owns 100 per cent of Tuscarora. At December 31, 2007, TransCanada held a 32.1 per cent interest in PipeLines LP.

In fourth-quarter 2007, the Company's Energy segment sold land in Ontario that had been previously held for development, generating net proceeds of $38 million.

In 2006, PipeLines LP acquired an additional 49 per cent interest in Tuscarora for US$100 million, subject to closing adjustments, in addition to indirectly assuming US$37 million of debt. PipeLines LP also acquired an additional 20 per cent general partnership interest in Northern Border for US$307 million, in addition to indirectly assuming US$122 million of debt. TransCanada sold its 17.5 per cent general partner interest in Northern Border Partners, L.P. for proceeds of $35 million, net of current tax.

In 2005, TransCanada obtained the remaining rights to full generating capacity under the Sheerness PPA for $585 million, invested $100 million in Bruce A as part of the Bruce Power reorganization, purchased the TC Hydro assets from USGen New England, Inc. for US$503 million and acquired an additional 3.52 per cent ownership interest in Iroquois for US$14 million. TransCanada sold its ownership interest in Power LP for proceeds of $444 million, net of current tax, and also sold its ownership interest of approximately 11 per cent in Paiton Energy for proceeds of $125 million, net of current tax, and PipeLines LP units for proceeds of $102 million, net of current tax.

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. In February 2007, the Company established a US$2.2-billion, committed, unsecured, one-year bridge loan facility and utilized $1.5 billion and US$700 million to partially finance its acquisition of ANR and its increased ownership in Great Lakes. At December 31, 2007, US$370 million remained outstanding on this facility.

At December 31, 2007, total unsecured revolving and demand credit facilities of $2.9 billion were available to support the Company's commercial paper program and for general corporate purposes. These credit facilities include the following:

- in December 2007, the $1.5 billion committed five-year term syndicated credit facility was increased to $2.0 billion and extended to December 2012. The cost to maintain the credit facility was $2 million in 2007 (2006 – $2 million).
- at December 31, 2007, a US$300 million five-year, extendible revolving facility was available, which is part of the US$1.0 billion TransCanada PipeLine USA Ltd. credit facility discussed below in the section "2007 Long-Term Debt Financing Activities".
- the Company also has in place $600 million of demand lines, which support the issuance of letters of credit and provide additional liquidity. The Company had used approximately $334 million of its total lines of credit for letters of credit at December 31, 2007. 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.

2007 Long-Term Debt Financing Activities

In March 2007, the Company filed debt shelf prospectuses in Canada and the U.S. qualifying for issuance $1.5 billion of Medium-Term Notes and US$1.5 billion of debt securities, respectively. At December 31, 2007, the Company had issued no Medium-Term Notes under the Canadian prospectus and, in September 2007, replaced the March 2007 U.S. debt shelf prospectus with a new US$2.5-billion U.S. debt shelf prospectus. In October 2007, TransCanada issued US$1.0 billion of Senior Unsecured Notes under the US$2.5-billion U.S. debt shelf prospectus. These notes mature on October 15, 2037 and bear interest at a rate of 6.20 per cent. US$1.5 billion remains available under the U.S. debt shelf at December 31, 2007.

In July 2007, TransCanada 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 part of the settlement on 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, TransCanada PipeLines Limited (TCPL) issued US$1.0 billion of Junior Subordinated Notes, maturing in 2067 and bearing interest of 6.35 per cent per year until May 15, 2017, when interest will convert to a floating rate, reset quarterly to the three-month London Interbank Offered Rate (LIBOR) 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. The Company would be prohibited from paying dividends during any 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 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 at the Company's option, in whole or in part, 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 formula in accordance with the terms of the Junior Subordinated Notes. The Junior Subordinated Notes were issued under the U.S. 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 on May 1, 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, which became effective April 12, 2007, ANR Pipeline deregistered these securities with the SEC.

In February 2007, the Company established a US$1.0 billion committed, unsecured credit facility, consisting of a US$700-million five-year term loan and a US$300-million five-year, extendible revolving facility. 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. At December 31, 2007, US$860 million remained outstanding on the committed facility and the demand line had been fully repaid.

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, 2007, US$507 million remained outstanding on the facility.

In January 2008, the Company retired $105 million of 6.0 per cent Medium-Term Notes. 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.

2006 Long-Term Debt Financing Activities

In 2006, TransCanada reduced its Long-Term Debt by $729 million, its Notes Payable by $495 million and its proportionate share of the Long-Term Debt of Joint Ventures by a net amount of $14 million. In January 2006, the Company issued $300 million of 4.3 per cent five-year Medium-Term Notes due 2011. In March 2006, the Company issued US$500 million of 5.85 per cent 30-year Senior Unsecured Notes due 2036. In October 2006, TransCanada issued $400 million of 4.65 per cent ten-year Medium-Term Notes due 2016.

In April 2006, PipeLines LP borrowed US$307 million under its unsecured credit facility to finance the cash portion of its acquisition of an additional 20 per cent interest in Northern Border. In December 2006, the credit facility was repaid in full and replaced with a US$410-million syndicated revolving credit and term loan agreement, of which US$397 million was drawn as at December 31, 2006, a portion of which was utilized to finance the acquisition of additional interests in Tuscarora. In February 2007, PipeLines LP increased the size of this facility, as discussed above.

2005 Long-Term Debt Financing Activities

In 2005, TransCanada reduced its Long-Term Debt by $1,113 million and increased its Notes Payable by $416 million. Financing activities included a net reduction in the Company's proportionate share of Long-Term Debt of Joint Ventures of $42 million. In June 2005, GTNC redeemed all of its outstanding US$150-million 7.8 per cent Senior Unsecured Debentures and US$250-million 7.1 per cent Senior Unsecured Notes. Following an application by GTNC, it no longer has any securities registered under U.S. securities laws. In June 2005, GTNC also completed a US$400-million multi-tranche private placement of senior debt with a weighted average interest rate of 5.28 per cent and weighted average life of approximately 18 years. In 2005, TransCanada also issued $300 million of 5.1 per cent Medium-Term Notes due 2017 under the Company's Canadian shelf prospectus.

2007 Equity Financing Activities

In January 2007, TransCanada filed a short form shelf prospectus with securities regulators in Canada and the U.S. to allow for the offering of up to $3.0 billion of common shares, preferred shares and/or subscription receipts in Canada and the U.S. until February 2009. In February and March 2007, the Company issued 45,390,500 common shares under the short form shelf prospectus, at a price of $38.00 each, resulting in gross proceeds of approximately $1.7 billion, which were used towards financing the ANR acquisition and increased ownership in Great Lakes.

In 2007, TransCanada's Board of Directors authorized the issuance of common shares from treasury at a discount of two per cent to participants in the Company's DRP. Under this plan, eligible shareholders may reinvest their dividends and make optional cash payments to obtain additional TransCanada common shares. Commencing with the dividend payable in April 2007, the DRP shares were provided to the participants at a two per cent discount to the average market price in the five days before dividend payment. Dividends of $157 million were paid in 2007 through the issuance of 4.1 million common shares issued from treasury in accordance with the DRP.

In February 2007, PipeLines LP completed a private placement offering of 17,356,086 common units at a price of US$34.57 per unit, of which 50 per cent were acquired by TransCanada for US$300 million. TransCanada also invested an additional US$12 million to maintain its general partnership ownership interest in PipeLines LP. As a result of these additional investments, TransCanada's ownership in PipeLines LP increased to 32.1 per cent on February 22, 2007. The total private placement together with TransCanada's additional general partnership investment resulted in gross proceeds to PipeLines LP of US$612 million, which were used to partially finance its acquisition of a 46.4 per cent ownership interest in Great Lakes.

Dividends

Cash dividends on common shares amounting to $546 million were paid in 2007 compared to cash dividends amounting to $617 million in 2006 and $586 million in 2005. The reduction in 2007 compared to 2006 reflected the Company's issuance of $157 million of common shares under the DRP, in lieu of cash dividends.

In January 2008, TransCanada's Board of Directors approved an increase in the quarterly common share dividend payment to $0.36 per share from $0.34 per share for the quarter ending March 31, 2008. This was the eighth consecutive year of dividend increase beginning with the dividend of $0.20 per share declared in fourth-quarter 2000 and represents an 80 per cent increase in the dividend over this period.

Issuer Ratings

TransCanada's issuer rating assigned by Moody's Investors Service (Moody's) is A3 with a stable outlook. TCPL's senior unsecured debt is rated A with a stable outlook by DBRS, A2 with a stable outlook by Moody's, and A− with a stable outlook by Standard and Poor's.

CONTRACTUAL OBLIGATIONS

Obligations and Commitments

At December 31, 2007, the Company had total long-term debt of $12.9 billion and $1.0 billion of Junior Subordinated Notes, compared to long-term debt of $11.5 billion at December 31, 2006. TransCanada's share of the total debt of joint ventures, including capital lease obligations, was $903 million at December 31, 2007, compared to $1.3 billion at December 31, 2006. Total notes payable, including TransCanada's proportionate share of the notes payable of joint ventures, were $421 million at December 31, 2007, compared to $467 million at December 31, 2006. The security provided by each joint venture, except for the capital lease obligation at Bruce Power, is limited to the rights and assets of the joint venture and does not extend to the rights and assets of TransCanada, but does extend to the Company's investment. TransCanada has provided certain pro-rata guarantees related to the capital lease obligations of Bruce Power and to the 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]	14,568	577	1,965	2,182	9,844
Capital lease obligations	243	9	23	33	178
Operating leases[2]	1,081	49	91	106	835
Purchase obligations	11,694	3,414	2,657	1,635	3,988
Other long-term liabilities reflected on the balance sheet	372	10	24	29	309
Total contractual obligations	27,958	4,059	4,760	3,985	15,154

(1) Includes Junior Subordinated Notes.

(2) Represents future annual payments, net of sub-lease receipts, for various premises, services, equipment and a natural gas storage facility. The operating lease agreements for premises expire at various dates through 2021, with an option to renew certain lease agreements for one to ten years. The operating lease agreement for the natural gas storage facility expires in 2030. The lessee has the right to terminate the agreement on anniversary dates five years apart commencing in 2010, and the lessor has the right to terminate the agreement on the same schedule commencing in 2015.

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 things. The amount of power purchased under the PPAs in 2007 was $440 million (2006 – $499 million; 2005 – $230 million).

At December 31, 2007, 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 follow:

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	12,933	556	1,619	2,051	8,707
Junior subordinated notes	975	–	–	–	975
Long-term debt of joint ventures	660	21	346	131	162
Total principal repayments	14,568	577	1,965	2,182	9,844

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
Interest payments on long-term debt	10,978	832	1,511	1,339	7,296
Interest payments on junior subordinated notes	588	63	125	125	275
Interest payments on long-term debt of joint ventures	332	55	85	53	139
Total interest payments	11,898	950	1,721	1,517	7,710

At December 31, 2007, the Company's approximate future purchase obligations were as follow:

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]	719	197	283	133	106
Capital expenditures[3][4]	1,677	1,107	567	3	–
Other	153	55	46	46	6
Energy					
Commodity purchases[5]	7,381	1,134	1,278	1,225	3,744
Capital expenditures[3][6]	1,293	723	354	168	48
Other[7]	377	175	83	42	77
Corporate					
Information technology and other	94	23	46	18	7
Total purchase obligations	11,694	3,414	2,657	1,635	3,988

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

(2) Rates are based on known 2008 levels. Beyond 2008, demand rates are subject to change. The contract 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 these projects with cash from operations and, if necessary, new debt.

(4) Primarily consists of capital expenditures related to TransCanada's share of the construction costs for Keystone 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) Primarily consists of capital expenditures related to TransCanada's share of the construction costs for Halton Hills, Portlands Energy and the remaining Cartier Wind projects.

(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 expects to make funding contributions to the Company's pension plans and other benefit plans in the amount of approximately $60 million and $14 million, respectively, in 2008. The expected increase in total pension and post-retirement benefits funding in 2008, from $61 million in 2007, is attributed primarily to a decline in the actual return on plan assets compared to investment performance expectations for 2007 and plan experience being different than expected. TransCanada's proportionate share of funding contributions expected to be made by joint ventures to their respective pension plans and other benefit plans in 2008 is approximately $31 million and $3 million, respectively.

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 to third-party suppliers related to refurbishing and restarting Units 1 and 2 and refurbishing Units 3 and 4 to extend their operating life. TransCanada's share of these signed commitments, which extend over the four-year period ending December 31, 2011, are as follow:

Year ended December 31 *(millions of dollars)*	
2008	360
2009	151
2010	69
2011	14
	594

Aboriginal Pipeline Group

On June 18, 2003, the Mackenzie Delta gas producers, the APG and TransCanada reached an agreement governing TransCanada's role in the MGP project to build a natural gas pipeline from Inuvik, Northwest Territories, to the northern border of Alberta, where it would connect with the Company's Alberta System. Under the agreement, TransCanada agreed to finance the APG for its one-third share of project pre-development costs. These costs are currently forecasted to be between $150 million and $200 million, depending on the pace of project development. As at December 31, 2007, the Company had advanced $137 million of this total.

TransCanada and the other co-venture companies involved in the MGP continue to pursue approval of the proposed project, focusing on the regulatory process and discussions with the Canadian government on the fiscal framework. Project timing is uncertain and is conditional upon resolution of regulatory and fiscal matters. TransCanada's ability to recover its investment depends on the successful outcome of the project.

Contingencies

The Canadian Alliance of Pipeline Landowners' Associations (CAPLA) and two individual landowners commenced an action in 2003 against TransCanada and Enbridge Inc. under Ontario's *Class Proceedings Act, 1992* for damages of $500 million. The damages are alleged to have arisen from the creation of a control zone within 30 metres of a pipeline pursuant to Section 112 of the *National Energy Board Act*. In November 2006, TransCanada and Enbridge Inc. were granted a dismissal of the case but CAPLA appealed the decision. The Ontario Court of Appeal heard the appeal on December 18, 2007, and reserved its decision. The Company continues to believe the claim is without merit and will vigorously defend the action. The Company has made no provision for any potential liability. A liability, if any, would be dealt with through the regulatory process.

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 and BPC have each severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, operator licenses, a lease agreement and contractor services. The guarantees have terms ranging from one year ending in 2008 to perpetuity.

TransCanada and BPC have each 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 part of the reorganization of Bruce Power in 2005 and have terms ending in 2019 to 2036. TransCanada's share of the potential exposure under these Bruce Power guarantees was estimated at December 31, 2007, to range from $711 million to a maximum of $750 million. The fair value of these guarantees is estimated to be $12 million.

The Company and its partners in certain jointly owned entities have severally and joint and severally guaranteed the performance of these entities related primarily to construction projects, 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, 2007 to range from $699 million to a maximum of $1,210 million. 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. Deferred Amounts includes $7 million for the fair value of these joint and several guarantees.

TransCanada has guaranteed a subsidiary's equity undertaking that supports the payment, under certain conditions, of principal and interest on US$75 million of the public debt obligations of TransGas. The Company has a 46.5 per cent interest in TransGas. Under the terms of a shareholder agreement, TransCanada and another major multinational company may be required to severally fund more than their proportionate share of debt obligations of TransGas in the event that the minority shareholders fail to contribute. Any payments made by TransCanada under this agreement convert into share capital of TransGas. The Company's potential exposure is contingent on the impact any change of law would have on the ability of TransGas to service the debt. There has been no change in applicable law since the issuance of debt in 1995 and, thus, no exposure for TransCanada. The debt matures in 2010. The Company has made no provision related to this guarantee.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

FINANCIAL RISKS

Risk Management Overview

TransCanada has exposure to market, counterparty credit and liquidity risk. The risk management function assists in managing these risks. TransCanada's primary risk management objective is to protect earnings and 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 established by the Company's Board of Directors, implemented by senior management and monitored by risk management personnel. TransCanada's Audit Committee oversees how management monitors compliance with risk management policies and procedures, and 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 commodities, issues short- 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 policy to manage exposures to market risk that result from these activities.

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, for 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.
- Heat rate contracts – contracts for the purchase or sale of power that are priced based on a natural gas index.

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 power and natural gas. A number of strategies are used to mitigate these exposures, including the following:

- The Company enters into offsetting or back-to-back physical positions and derivative financial instruments to manage market risk exposures created by certain fixed and variable pricing arrangements at different pricing indices and delivery points.
- Subject to the Company's overall risk management policies, the Company commits a significant portion of its power supply to medium- or long-term sales contracts, while reserving an amount of unsold supply to maintain operational flexibility in the overall management of its asset portfolio.
- The Company purchases a portion of the natural gas required for its gas-fired cogeneration plants or enters into heat-rate 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 requirements is purchased with forward contracts or fulfilled through power generation, thereby reducing the Company's exposure to fluctuating commodity prices.

The Company assesses its commodity contracts and derivative instruments used to manage energy commodity risk to determine the appropriate accounting treatment. Contracts, with the exception of leases, have been assessed to determine whether they meet the definition of a derivative. Certain commodity purchase and sale contracts are derivatives but are not within the scope of 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 normal purchases and normal sales exemption. 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 hedging storage capacity with a portfolio of third-party storage capacity leases and proprietary natural gas purchases and sales. By matching purchase and sale volumes, TransCanada locks in a margin on a back-to-back basis and thereby effectively eliminates its exposure to natural gas market price fluctuations.

Natural Gas Inventory Price Risk

Effective April 1, 2007, TransCanada began valuing its proprietary natural gas inventory held in storage at fair value, as measured by the one-month forward price for natural gas. At December 31, 2007, $190 million of proprietary natural gas inventory was included in Inventories. The amount recorded in 2007 in Revenues for the net change in the fair value of proprietary natural gas held in inventory was insignificant. A gain of $10 million was recorded in 2007 in Revenues for the net change in fair value of the forward proprietary natural gas purchase and sales contracts.

Foreign Exchange and Interest Rate Risk

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

A portion of TransCanada's earnings from its Pipelines and Energy operations outside of Canada is generated primarily in U.S. dollars and is subject to currency fluctuations. The performance of the Canadian dollar relative to the U.S. dollar could positively or negatively affect TransCanada's earnings. This foreign exchange impact is offset by exposures in certain of TransCanada's businesses and by the Company's hedging activities. Due to its growing operations in the U.S., including the acquisitions of ANR and additional interests in Great Lakes and PipeLines LP, TransCanada expects to have a greater exposure to U.S. dollar fluctuations than in prior years.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to its U.S. dollar-denominated debt and other transactions, as well as to manage the interest rate exposures of the Canadian Mainline, Alberta System and Foothills. 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.

The Company has fixed-rate long-term debt, which subjects it to interest rate price risk, and has floating interest rate debt, which subjects it to interest rate cash flow risk. The Company uses a combination of forwards, interest rate swaps and options to manage its exposure to these risks.

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, forward contracts, cross-currency interest rate swaps and options. The Company had designated U.S. dollar-denominated debt with a carrying value of $4.7 billion (US$4.7 billion) and a fair value of $4.8 billion (US$4.8 billion) as a net investment hedge at December 31, 2007. The forwards, swaps and options are recorded at their fair value and are included in Other Assets.

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

Asset/(Liability)	**2007**		2006	
December 31 (millions of dollars)	**Fair Value[(1)]**	**Notional or Principal Amount**	Fair Value[(1)]	Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2009 to 2014)	**77**	**U.S. 350**	58	U.S. 400
U.S. dollar options (maturing 2008)	**3**	**U.S. 600**	(6)	U.S. 500
U.S. dollar forward foreign exchange contracts (maturing 2008)	**(4)**	**U.S. 150**	(7)	U.S. 390
	76	**U.S. 1,100**	45	U.S. 1,290

(1) Other Comprehensive Income in 2007 included unrealized foreign currency translation losses of $350 million (2006 – gains of $6 million; 2005 – losses of $34 million) related to the change in value of investments in foreign operations. Other Comprehensive Income also included unrealized gains of $79 million (2006 – losses of $6 million; 2005 – gains of $15 million) for changes in fair value of hedges of investments in foreign operations.

VaR Analysis

TransCanada uses a Value-at-Risk methodology (VaR) to estimate the potential impact resulting from its exposure to market risk. 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 the 95 per cent probability that the daily change resulting from normal market fluctuations in its liquid positions will not exceed the reported VaR. VaR methodology is a statistically-defined, probability-based approach that takes into consideration market volatilities as well as risk diversification by recognizing offsetting positions and correlations between products and markets. Risks are measured across all products and markets, and risk measures can be 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 and limits TransCanada's ability to manage these risks. The Company'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 less than $10 million at December 31, 2007.

Counterparty Credit Risk

Counterparty credit risk represents the financial loss that the Company would experience if a counterparty to a financial instrument, in which the Company has an amount owing from the counterparty, failed to meet its obligations in accordance with the terms and conditions of its contracts with the Company.

Counterparty credit risk is mitigated 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, utilizing 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.

TransCanada's maximum counterparty credit exposure at the balance sheet date consists primarily of the carrying amount of non-derivative financial assets as well as the fair value of derivative financial assets.

The Company has contracts for the sale of non-financial items. Many of these contracts do not meet the definition of a financial instrument since the underlying volumes are physically delivered during the Company's normal course of business. Exposure to counterparty credit risk on these non-financial contracts results from the potential of a counterparty defaulting on invoiced amounts owing to TransCanada. These invoiced amounts are included in the Accounts Receivable and Other Assets amounts disclosed in the Non-Derivative Financial Instruments Summary table presented later in this section. Some of these non-financial contracts do meet the definition of a derivative and are recorded at fair value.

The carrying amounts and fair values of financial assets and non-financial derivatives are disclosed in the Non-Derivative Financial Instruments Summary and the Derivative Financial Instruments Summary tables presented later in this section.

The Company does not have any significant concentrations of counterparty credit risk and the majority of the counterparty credit exposure is with counterparties who are investment grade.

The Company has reached agreements for allowed unsecured claims with certain subsidiaries of Calpine, former shippers on TransCanada's pipeline systems that have filed for bankruptcy protection, as discussed in the "Pipelines – Outlook" section of this MD&A.

Liquidity Risk

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

Management typically forecasts cash flows for a period of 12 months to identify financing requirements. These requirements are then addressed through a combination of committed and demand credit facilities, and through access to capital markets.

Fair Values

The fair value of Cash and Cash Equivalents and Notes Payable approximates their carrying amounts due to the short time period 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 heat rate derivatives has been calculated using estimated forward prices for the relevant period.

Fair values of financial instruments are determined by reference to quoted bid or asking price, as appropriate, in active markets at period-end dates. In the absence of an active market, the Company determines fair value by using valuation techniques that refer to observable market data or estimated market prices. These include comparisons with similar instruments that have observable market prices, option pricing models and other valuation techniques commonly used by market participants. Fair values determined using valuation models require the use of assumptions about the amount and timing of estimated future cash flows and discount rates. In making these assumptions, the Company looks primarily to readily observable external market input factors such as interest rate yield curves, currency rates, and price and rate volatilities as applicable.

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, by discounting future payments of interest and principal at estimated interest rates that were made available to the Company at December 31, 2007.

Non-Derivative Financial Instruments Summary

The carrying and fair values of non-derivative financial instruments were as follow:

December 31, 2007 *(millions of dollars)*	Carrying Amount	Fair Value
Financial Assets[1]		
Cash and cash equivalents	**504**	**504**
Accounts receivable and other assets[2][3]	**1,231**	**1,231**
Available-for-sale assets[2]	**17**	**17**
	1,752	**1,752**
Financial Liabilities[1][3]		
Notes payable	**421**	**421**
Accounts payable and deferred amounts[4]	**1,454**	**1,454**
Long-term debt and junior subordinated notes	**13,908**	**15,340**
Long-term debt of joint ventures	**903**	**937**
Other long-term liabilities of joint ventures[4]	**60**	**60**
	16,746	**18,212**

(1) Consolidated Net Income in 2007 included unrealized gains or losses of nil for the fair value adjustments to each of these financial instruments.

(2) The Consolidated Balance Sheet included financial assets of $1,018 million in Accounts Receivable and $230 million in Other Assets at December 31, 2007.

(3) Recorded at amortized cost, except for Long-Term Debt of $150 million and US$200 million adjusted to fair value.

(4) The Consolidated Balance Sheet included financial liabilities of $1,436 million in Accounts Payable and $78 million in Deferred Amounts at December 31, 2007.

Derivative Financial Instruments Summary

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

	2007			
December 31 (all amounts in millions unless otherwise indicated)	**Power**	**Natural Gas**	**Foreign Exchange**	**Interest**
Derivative Financial Instruments Held for Trading				
Fair Values[1]				
Assets	$55	$43	$11	$23
Liabilities	$(44)	$(19)	$(79)	$(18)
Notional Values				
Volumes[2]				
Purchases	3,774	47	–	–
Sales	4,469	64	–	–
Canadian dollars	–	–	–	615
U.S. dollars	–	–	U.S. 484	U.S. 550
Japanese yen (in billions)	–	–	JPY 9.7	–
Cross-currency	–	–	227/U.S. 157	–
Unrealized gains/(losses) in the period[3]	$16	$(10)	$8	$(5)
Realized (losses)/gains in the period[3]	$(8)	$47	$39	$5
Maturity dates	2008 - 2016	2008 - 2010	2008 - 2012	2008 - 2016
Derivative Financial Instruments in Hedging Relationships[4][5][6]				
Fair Values[1]				
Assets	$135	$19	$ –	$2
Liabilities	$(104)	$(7)	$(62)	$(16)
Notional Values				
Volumes[2]				
Purchases	7,362	28	–	–
Sales	16,367	4	–	–
Canadian dollars	–	–	–	150
U.S. dollars	–	–	U.S. 113	U.S. 875
Cross-currency	–	–	136/U.S. 100	–
Realized (losses)/gains in the period[3]	$(29)	$18	$ –	$3
Maturity dates	2008 - 2013	2008 - 2010	2008 - 2013	2008 - 2013

(1) Fair value is equal to the carrying value of these derivatives.

(2) Volumes for power and natural gas derivatives are in gigawatt hours and billion cubic feet, respectively.

(3) All realized and unrealized gains and losses are included in Net Income. Realized gains are included in Net Income after the financial instrument has been settled.

(4) All hedging relationships are designated as cash flow hedges except for $2 million of interest-rate derivative financial instruments designated as fair value hedges.

(5) Net Income in 2007 included gains of $7 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. Net Income in 2007 included a loss of $4 million for the changes in fair value of an interest-rate cash flow hedge that was reclassified as a result of discontinuance of cash flow hedge accounting. The cash flow hedge accounting was discontinued when the anticipated transaction was not probable of occurring by the end of the originally specified time period.

(6) Other Comprehensive Income in 2007 included unrealized gains of $42 million for the change in fair value of cash flow hedges.

Balance Sheet Presentation of Derivative Financial Instruments
The fair values of the derivative financial instruments in the Company's Balance Sheet were as follow:

December 31 (millions of dollars)	**2007**
Current	
Other Current Assets	**160**
Accounts Payable	**(144)**
Long-term	
Other Assets	**204**
Deferred Amounts	**(205)**

OTHER RISKS

Development Projects and Acquisitions
TransCanada continues to focus on growing its Pipelines and Energy operations through greenfield projects and acquisitions. TransCanada capitalizes costs incurred on certain of its greenfield development projects during the 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 would be expensed at the time it is discontinued. There is a risk with respect to TransCanada's acquisition of existing assets and operations that certain commercial opportunities and operational synergies may not materialize as expected.

Health, Safety and Environment Risk Management
TransCanada is committed to providing a safe and healthy environment for its employees, contractors and the public, and to protecting the environment. Health, safety and environment (HS&E) is a priority in all of TransCanada's operations and the Company is committed to ensuring it is in conformance with its internal policies and regulated requirements, and is an industry leader. The HS&E Committee of TransCanada's Board of Directors monitors conformance with TransCanada's HS&E corporate policy through regular reporting. TransCanada's HS&E management system is modeled to the elements of the International Organization of Standardization (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 regularly advised of all important HS&E operational issues and initiatives by way of formal reporting processes. TransCanada's HS&E management system and performance are assessed by an independent outside firm every three years or more often if requested by the HS&E Committee. The most recent assessment was conducted in November 2006. These assessments involve senior management and employee interviews, review of policies, procedures, objectives, performance measurement and reporting.

Health and Safety
In 2007, employee and contractor health and safety performance continued to improve relative to previous years and benchmarked within the top level of industry peers. The Company's assets were highly reliable in 2007 and there were no incidents that were material to the Company's operations.

Under the approved regulatory models in Canada, pipeline integrity expenditures on NEB-and AUC-regulated pipelines are treated on a flow-through basis and, as a result, have no impact on TransCanada's earnings. The Company expects to spend approximately $120 million in 2008 for pipeline integrity on its wholly owned pipelines, which is slightly higher than the amount spent in 2007, reflecting the acquisition of ANR and slightly increased spending in Canada. Spending associated with public safety on the Energy assets is focused primarily on hydro dams and associated equipment, and is consistent with previous years.

Environment

TransCanada's operations are subject to various environmental laws and regulations that establish compliance and remediation obligations. There are no outstanding orders, material 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. The Company believes that it has established appropriate reserves, where required, for environmental liabilities.

Environmental risks from TransCanada's facilities typically include air emissions such as nitrogen oxides (NOx), particulate matter and greenhouse gases, potential land impacts, including land reclamation following construction, releases, chemical and hydrocarbon storage, and waste management control to minimize hazardous wastes, and water impacts such as water discharge. TransCanada utilizes a risk-based environmental assessment approach. All businesses are assessed annually and specific facilities, installations and activities are reviewed on a one- to three-year cycle, depending on the Company's assessment of risk. Business and/or facility inspections are completed on a monthly, quarterly or annual basis, depending on the entity and the assessment of risk. There were no materially significant environmental matters arising from these assessments conducted during 2007.

Climate change policy continues to evolve at regional, national and international levels. Under the Specified Gas Emitters Regulation, as of July 1, 2007, industrial facilities in Alberta are required to reduce their greenhouse gas emissions intensities by 12 per cent. TransCanada's Alberta-based facilities are subject to this regulation, which also extends to the Sundance and Sheerness facilities with which the Company has PPAs. Plans have been developed to manage the costs of compliance incurred by these assets. The regulation is not expected to have a material impact on the Company's results. Compliance costs related to the Alberta System are expected to be recovered through tolls paid by customers. Recovery of compliance costs related to the Company's power generation facilities in Alberta is dependent ultimately on market prices for electricity. The Company recorded a charge of $14 million for the period from July 1, 2007 to December 31, 2007 related to the new Alberta environmental regulation.

A hydrocarbon royalty tax took effect in Québec on October 1, 2007 and is expected to affect mainly the Bécancour power generation facility. A regulatory proceeding is under way to determine the method of collecting the tax. The Company recorded a charge of $2 million for the period October 1, 2007 to December 31, 2007 for Québec royalties.

British Columbia recently announced a carbon tax, with an effective date of July 2008, which is expected to be applied to fuel usage at the Company's pipeline compressor facilities in that province. The specifics of the application of the tax are still being assessed. Compliance costs related to this tax are anticipated to be recovered through tolls paid by customers.

The Government of Canada released in April 2007 the Regulatory Framework for Air Emissions (Framework). The Framework outlines short-, medium- and long-term objectives for managing both greenhouse gas emissions and air pollutants in Canada. The Company expects a number of its facilities will be affected by pending Federal climate change regulations that will be put in place to meet the Framework's objectives. It is unknown at this time whether the impacts from the pending regulations will be material as the final form of compliance options is still evolving.

Climate change legislation is evolving at both the federal and state levels in the U.S. The Company expects a number of its facilities could be affected by these legislative initiatives, but timing and specific policy objectives remain uncertain.

The Company continues to be involved in discussions with governments in jurisdictions where TransCanada has operations and where climate change policy is under development. TransCanada is also continuing its programs to manage greenhouse gas emissions from its facilities and to evaluate new processes and technologies that result in improved efficiencies and lower greenhouse gas emission rates. The Company also incorporates compliance costs associated with environmental regulations as part of its normal assessment of existing operations and new growth opportunities.

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, 2007, an evaluation was carried out under the supervision of and with the participation of management, including the President and Chief Executive Officer and Chief Financial Officer, 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. 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, 2007.

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. In 2007, the Company acquired ANR and began consolidating the operations of ANR into the Company. Management excluded this business from its evaluation of the effectiveness of the Company's internal control over financial reporting as at December 31, 2007. The net income attributable to this business represented approximately nine per cent of the Company's consolidated net income in 2007, and its aggregate total assets represented approximately 12 per cent of the Company's consolidated total assets as at December 31, 2007.

Based on this evaluation, management concluded that internal control over financial reporting is effective as at December 31, 2007, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

In 2007, 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 has provided the New York Stock Exchange with the annual CEO certification for 2007 regarding TransCanada's compliance with the New York Stock Exchange's corporate governance listing standards applicable to foreign issuers. In addition, 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 2007 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. The Company uses the most current information available and exercises careful judgment in making these estimates and assumptions.

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 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 will be 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 that 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, in order to appropriately reflect the economic impact of the regulators' decisions regarding the Company's revenues and tolls, and to thereby achieve a proper matching of revenues and expenses, the timing of recognition of certain expenses and revenues in the regulated businesses may differ from that otherwise expected under GAAP.

Financial Instruments
Effective January 1, 2007, the Company adopted the new Canadian Institute of Chartered Accountants (CICA) Handbook accounting requirements for Section 3855 "Financial Instruments – Recognition and Measurement" and Section 3865 "Hedges". The CICA Handbook requirements for Section 3862 "Financial Instruments – Disclosure" and Section 3863 "Financial Instruments – Presentation" are effective January 1, 2008, however the Company chose to adopt these standards effective December 31, 2007.

These standards are described further in the "Risk Management and Financial Instruments" and "Accounting Changes" sections 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. Pipeline and compression equipment are depreciated at annual rates ranging from two per cent to six 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 amortized on a straight-line basis over the shorter of their useful life and the remaining terms of their lease. Other 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 to 20 per cent.

Depreciation expense in 2007 was $1,179 million (2006 – $1,059 million) and primarily affects the Pipelines and Energy segments of the Company. In Pipelines, depreciation rates are approved by regulators where applicable and depreciation expense is recoverable based on the cost of providing the services or products. If regulators permit recovery through rates, a change in the estimate of the useful lives of plant, property and equipment in the Pipelines segment would have no material impact on TransCanada's net income but would directly affect funds generated from operations.

ACCOUNTING CHANGES

Changes in Accounting Policies for 2007
Effective January 1, 2007, the Company adopted the CICA Handbook accounting requirements for Sections 1506 "Accounting Changes", 1530 "Comprehensive Income", 3251 "Equity", 3855 "Financial Instruments – Recognition and

Measurement", and 3865 "Hedges". In addition, the Company chose to adopt the accounting requirements for Sections 3862 "Financial Instruments – Disclosure", 3863 "Financial Instruments – Presentation" and 1535 "Capital Disclosures" at December 31, 2007, as well as the accounting requirements for Section 3031 "Inventories" at April 1, 2007. Adjustments to the consolidated financial statements for 2007 have been made in accordance with the transitional provisions for these new standards.

Comprehensive Income and Equity

The Company's financial statements include statements of Consolidated Comprehensive Income and Consolidated Accumulated Other Comprehensive Income. In addition, as required in CICA Handbook Section 3251, the Company now presents separately, in the Consolidated Shareholders' Equity statement, the changes for each of its components of Shareholders' Equity, including Accumulated Other Comprehensive Income.

Financial Instruments

All financial instruments must initially be included 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 financial assets and liabilities consist of swaps, options, forwards and futures, and are entered into with the intention of generating a profit. A financial asset or liability that does not meet this criterion may also be designated as held for trading. Power and natural gas held-for-trading 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 held-for-trading instruments are recorded in Financial Charges and in Interest Income and Other, respectively. The Company had not designated any financial assets or liabilities as held for trading at December 31, 2007.

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. TransCanada's available-for-sale financial instruments include fixed-income securities held for self-insurance. These instruments are initially accounted for 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 will be included in Interest Income and Other.

Held-to-maturity financial assets are accounted for at their amortized cost using the effective interest method. The Company did not have any held-to-maturity financial assets at December 31, 2007.

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 net of any impairment. Loans and receivables include primarily trade accounts receivable and non-interest-bearing third-party loans 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. Interest expense is included in Financial Charges and in Financial Charges of Joint Ventures. Items in this financial instrument category are recognized at amortized cost using the effective interest method.

All derivatives are recorded on the balance sheet at fair value, with the exception of those 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 (normal purchase and normal sale exemption). Changes in the 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 under the heading Hedges in this section.

Derivatives embedded in other financial instruments or contracts (the 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 derivates that are recorded separately are included in Revenues. The Company used January 1, 2003 as the transition date for embedded derivatives.

Transaction costs are incremental costs that are directly attributable to the acquisition, issue or disposal of a financial instrument. Effective January 1, 2007, the Company began offsetting long-term debt transaction costs against the associated debt and began amortizing these costs using the effective interest method. Previously, these costs were amortized on a straight-line basis over the life of the debt. There was no material impact on the Company's financial statements as a result of this change in policy. In 2007, the impact on Net Income for the amortization of transaction costs using the effective interest method was nominal.

The Company records the fair values of material joint and several guarantees. These fair values cannot be readily obtained from an open market and therefore, 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 in Deferred Amounts.

Hedges

Section 3865 specifies the criteria that must be satisfied in order to apply hedge accounting and the accounting for each of the permitted hedging strategies, including: fair value hedges, cash flow hedges and hedges of foreign currency exposures of net investments in self-sustaining foreign operations. Hedge accounting is discontinued prospectively when the derivative no longer qualifies as an effective hedge or is terminated or sold, or upon the sale or early termination of the hedged item.

Documentation must be prepared at the inception of the hedging arrangement in order to qualify for hedge accounting treatment. In addition, the Company must perform an assessment of effectiveness at inception of the contract and at each reporting date.

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 is also recorded in Net Income. Changes in the fair value of foreign exchange and interest rate hedges are recorded in Interest Income and Other and Financial Charges, 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 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 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. The gains and losses arising from the changes in 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 recognized in Net Income in the event the Company settles or otherwise reduces its investment.

Net Effect of Accounting Policy Changes

The net effect of the preceding accounting policy changes on the Company's financial statements at January 1, 2007 was as follows:

Increases/(decreases) *(millions of dollars)*	
Other current assets	(127)
Other assets	(203)
Accounts payable	(29)
Deferred amounts	(75)
Future income taxes	(42)
Long-term debt	(85)
Long-term debt of joint ventures	(7)
Accumulated other comprehensive income	(96)
Retained earnings	4

The primary changes in 2007 to the Company's accounting policies for financial instruments related to the requirements to record certain non-financial contracts at their fair value and to offset transaction costs against long-term debt.

Section 3862 Financial Instruments – Disclosures and Section 3863 Financial Instruments – Presentation

CICA Handbook Sections 3862 "Financial Instruments – Disclosure" and 3863 "Financial Instruments – Presentation", which replaced Section 3861 "Financial Instruments – Disclosure and Presentation", are effective January 1, 2008. However, the Company chose to adopt these standards effective December 31, 2007. The Company's December 31, 2007 financial statements provided the additional disclosure necessary to comply with these standards.

Section 1535 Capital Disclosures

CICA Handbook Section 1535 "Capital Disclosures" is effective for fiscal years beginning on or after October 1, 2007, however, TransCanada chose to adopt this standard effective December 31, 2007. The Company has provided qualitative disclosure regarding objectives, policies and processes for managing capital as well as quantitative data of capital as of December 31, 2007 in the "Risk Management and Financial Instruments" section of this MD&A.

Proprietary Natural Gas Inventories and Revenue Recognition

CICA Handbook Section 3031 "Inventories" is effective January 1, 2008. However, the Company chose to adopt this standard effective April 1, 2007, and began valuing its proprietary natural gas inventory held in storage at fair value, as measured by the one-month forward price for natural gas. 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. TransCanada did not have any proprietary natural gas inventory prior to April 1, 2007. The Company records its proprietary natural gas storage results in Revenues net of Commodity Purchases Resold. All changes in the fair value of the proprietary natural gas inventories are reflected in Inventories and Revenues.

Future Accounting Changes

Rate-Regulated Operations

Effective January 1, 2009, the temporary exemption from CICA Handbook Section 1100, "Generally Accepted Accounting Principles", which permits the recognition and measurement of assets and liabilities arising from rate regulation, will be withdrawn. In addition, Section 3465 "Income Taxes" was amended to require the recognition of future income tax liabilities and assets. As a result of the changes, TransCanada will be required to recognize future income tax liabilities and assets instead of using the taxes payable method, and will record an offsetting adjustment to regulatory assets and liabilities. If the liability method of accounting had been used at December 31, 2007, additional future income tax liabilities in the amount of $1,138 million would have been recorded and would have been recoverable from future revenue. These changes will be applied prospectively beginning January 1, 2009.

International Financial Reporting Standards

The CICA's Accounting Standards Board (AcSB) announced that Canadian publicly accountable enterprises will adopt International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. IFRS will require increased financial statement disclosure. Although IFRS uses a conceptual framework similar to Canadian GAAP, differences in accounting policies will need to be addressed. TransCanada is currently assessing the impact of this AcSB announcement on its financial statements.

Intangible Assets

The CICA Handbook implemented revisions to standards dealing with Intangible Assets effective for fiscal years beginning on or after October 1, 2008. The revisions are intended to align the definition of an Intangible Asset in Canadian GAAP with that in IFRS and U.S. GAAP. Section 1000 "Financial Statement Concepts" was revised to remove material that permitted the recognition of assets that might not otherwise meet the definition of an asset and to add guidance from the IASB's "Framework for the Preparation and Presentation of Financial Statements" that will help distinguish assets from expenses. Section 3064 "Goodwill and Intangible Assets", which replaced Section 3062 "Goodwill and Other Intangible Assets", gives guidance on the recognition of intangible assets as well as the recognition and measurement of internally developed intangible assets. Section 3450 "Research and Development Costs" will be withdrawn from the Handbook. The Company does not expect these changes to have a material effect on its financial statements.

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA[(1)]

	2007			
(millions of dollars except per share amounts)	**Fourth**	**Third**	**Second**	**First**
Revenues	**2,189**	**2,187**	**2,208**	**2,244**
Net Income				
Continuing operations	**377**	**324**	**257**	**265**
Discontinued operations	**–**	**–**	**–**	**–**
	377	**324**	**257**	**265**
Share Statistics				
Net income per share – Basic				
Continuing operations	**$0.70**	**$0.60**	**$0.48**	**$0.52**
Discontinued operations	**–**	**–**	**–**	**–**
	$0.70	**$0.60**	**$0.48**	**$0.52**
Net income per share – Diluted				
Continuing operations	**$0.70**	**$0.60**	**$0.48**	**$0.52**
Discontinued operations	**–**	**–**	**–**	**–**
	$0.70	**$0.60**	**$0.48**	**$0.52**
Dividend declared per common share	**$0.34**	**$0.34**	**$0.34**	**$0.34**

	2006			
(millions of dollars except per share amounts)	Fourth	Third	Second	First
Revenues	2,091	1,850	1,685	1,894
Net Income				
Continuing operations	269	293	244	245
Discontinued operations	–	–	–	28
	269	293	244	273
Share Statistics				
Net income per share – Basic				
Continuing operations	$0.55	$0.60	$0.50	$0.50
Discontinued operations	–	–	–	0.06
	$0.55	$0.60	$0.50	$0.56
Net income per share – Diluted				
Continuing operations	$0.54	$0.60	$0.50	$0.50
Discontinued operations	–	–	–	0.06
	$0.54	$0.60	$0.50	$0.56
Dividend declared per common share	$0.32	$0.32	$0.32	$0.32

(1) The selected quarterly consolidated financial data has been prepared in accordance with Canadian GAAP. Certain comparative figures have been reclassified to conform with the current year's presentation.

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 earnings fluctuate over the long term based on regulators' decisions and negotiated settlements with shippers. Generally, quarter-over-quarter revenues and net earnings 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 earnings are affected by seasonal weather conditions, customer demand, market prices, planned and unplanned plant outages, acquisitions and divestitures, and developments outside of the normal course of operations.

Significant developments that affected quarterly net earnings in 2007 and 2006 were as follow:

- First-quarter 2006 net earnings included proceeds of $18-million after tax ($29-million pre-tax) from a bankruptcy settlement with a former shipper on the GTN System.
- Second-quarter 2006 net earnings included $33 million of future income tax benefits as a result of reductions in Canadian federal and provincial corporate income tax rates. Net earnings also included a $13-million after-tax gain related to the sale of the Company's interest in Northern Border Partners, L.P.
- Third-quarter 2006 net earnings included an income tax benefit of approximately $50 million as a result of the resolution of certain income tax matters with taxation authorities and changes in estimates.
- Fourth-quarter 2006 net earnings included approximately $12 million related to income tax refunds and related interest.
- First-quarter 2007 net earnings included $15 million related to positive income tax adjustments. In addition, Pipelines' net earnings included contributions from the February 22, 2007, acquisition of ANR and an additional ownership interest in Great Lakes. Energy's net earnings included earnings from the Edson natural gas facility, which was placed in service on December 31, 2006.
- Second-quarter 2007 net earnings included $16 million ($4 million in Energy and $12 million in Corporate) related to positive income tax adjustments resulting from reductions in Canadian federal income tax rates. Pipeline's net earnings increased as a result of a settlement reached on the Canadian Mainline, which was approved by the NEB in May 2007.
- Third-quarter 2007 net earnings included $15 million of favourable income tax reassessments and associated interest income relating to prior years.
- Fourth-quarter 2007 net earnings included $56 million ($30 million in Energy and $26 million in Corporate) of favourable income tax adjustments resulting from reductions in Canadian federal income tax rates and other legislative changes, and a $14-million ($16 million pre-tax) gain on sale of land previously held for development. Pipelines' net earnings increased as a result of recording incremental earnings related to the rate case settlement reached for the GTN System, effective January 1, 2007.

FOURTH-QUARTER 2007 HIGHLIGHTS

CONSOLIDATED RESULTS OF OPERATIONS
Reconciliation of Comparable Earnings to Net Income

(millions of dollars except per share amounts)	**2007**	2006
Pipelines Net Earnings	**202**	126
Energy Net Earnings		
Comparable earnings[1]	**114**	132
Specific items:		
Income tax reassessments and adjustments	**30**	–
Gain on sale of land	**14**	–
Net earnings	**158**	132
Corporate Net Earnings		
Comparable earnings[1]	**(9)**	(1)
Specific item:		
Income tax reassessments and adjustments	**26**	12
Net earnings	**17**	11
Net Income	**377**	269
Net Income per Share		
Basic	**$0.70**	$0.55
Diluted	**$0.70**	$0.54
Comparable Earnings[1]	**307**	257
Specific items (net of tax, where applicable):		
Income tax reassessments and adjustments	**56**	12
Gain on sale of land	**14**	–
Net Income	**377**	269
Comparable Earnings per Share[1]	**$0.57**	$0.53
Specific items – per share:		
Income tax reassessments and adjustments	**0.10**	0.02
Gain on sale of land	**0.03**	–
Net Income per Share	**$0.70**	$0.55

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

TransCanada's net income and net earnings in fourth-quarter 2007 were $377 million or $0.70 per share compared to $269 million or $0.55 per share in fourth-quarter 2006, an increase of $108 million or $0.15 per share. The increase reflected the impact of favourable income tax adjustments of $56 million in fourth-quarter 2007 as a result of changes in Canadian federal income tax legislation compared to income tax refunds and related interest of $12 million in fourth-quarter 2006. The increase was also due to additional earnings from the acquisition of ANR in February 2007 and the start-up of the Edson facility in December 2006, the positive impact of the rate case settlements on both the GTN System and the Canadian Mainline, a $14-million after-tax ($16 million pre-tax) gain on the sale of land and lower operating costs on the Alberta System. Lower realized power prices in Alberta and a lower contribution from Bruce Power partially offset these increases to net earnings in fourth-quarter 2007 compared to fourth-quarter 2006. The per-share net income increase of $0.15 in fourth-quarter 2007 was achieved despite an increased number of shares outstanding following the Company's share issuances in 2007.

Comparable earnings in fourth-quarter 2007 were $307 million or $0.57 per share, compared to $257 million or $0.53 per share in the same period in 2006. Comparable earnings excluded the $56-million and $12-million positive income tax adjustments in fourth-quarter 2007 and fourth-quarter 2006, respectively, as well as the $14-million gain on sale of land in fourth-quarter 2007.

In Pipelines, net earnings were $202 million in fourth-quarter 2007, an increase of $76 million from $126 million in the same period in 2006. Additional income from the acquisition of ANR, the positive impact of the rate case settlements on both the Canadian Mainline and the GTN System, and lower operating costs on the Alberta System contributed to higher earnings.

Canadian Mainline's net earnings in fourth-quarter 2007 were $72 million, an increase of $12 million from the corresponding period in 2006. The increase reflected the impact of the five-year rate case settlement on the Canadian Mainline, effective January 1, 2007 to December 31, 2011. Canadian Mainline's net earnings increased due to certain performance-based incentive arrangements and OM&A cost savings in addition to the positive impact of the increase in deemed common equity ratio in the settlement. Partially offsetting these increases were the negative impacts of a lower allowed ROE of 8.46 per cent in 2007 (2006 – 8.88 per cent) and a lower average investment base.

Alberta System's net earnings in fourth-quarter 2007 were $41 million, an increase of $7 million from the same quarter of 2006. The increase was due mainly to OM&A cost savings, partially offset by a lower investment base as well as a lower allowed ROE in 2007. Earnings in 2007 reflected an ROE of 8.51 per cent compared to 8.93 per cent in 2006, both on deemed common equity of 35 per cent.

GTN's comparable earnings in fourth-quarter 2007 were $32 million, an increase of $25 million from the same period in 2006 due primarily to the positive impact of the rate case settlement. GTN recorded the full-year impact of the rate case settlement in fourth-quarter 2007 upon receipt of FERC approval in January 2008. The positive impact of the rate case settlement on net earnings was partially offset by the impacts of lower long-term firm contracted volumes and a weaker U.S. dollar in 2007 as well as a higher provision taken in 2007 for non-payment of contract revenues from a subsidiary of Calpine that filed for bankruptcy protection.

In Energy, fourth-quarter 2007 net earnings were $158 million, an increase of $26 million from $132 million in the same period in 2006. Net earnings in fourth-quarter 2007 included $30 million of positive income tax reassessments and adjustments, a $14-million after-tax ($16 million pre-tax) gain on sale of land, higher prices and volumes at Bruce B, and revenue from the Edson facility, which commenced operation in December 2006. These gains were partially offset by lower overall realized power prices in Western Power as well as lower volumes and increased outage days and related costs at Bruce A.

Western Power's operating income in fourth-quarter 2007 was $58 million, a decrease of $51 million from fourth-quarter 2006. This decrease was due primarily to lower overall realized power prices and lower market heat rates on higher uncontracted volumes of power sold, partially offset by lower PPA costs. Average spot market power prices in Alberta decreased 47 per cent, or $55 per MWh, in fourth-quarter 2007 compared to fourth-quarter 2006. The power price decrease was also the main contributor to a decrease of approximately 43 per cent in market heat rates, partially offset by an 11 per cent, or $0.73 per GJ, decrease in average spot market natural gas prices in Alberta in fourth-quarter 2007 compared to the same quarter in 2006.

Eastern Power's operating income in fourth-quarter 2007 was $66 million, an increase of $11 million from the same period in 2006. The increase was due primarily to payments received under the newly-designed FCM in New England and increased earnings from higher sales volumes to commercial and industrial customers. These positive impacts were partially offset by decreased power generation from the TC Hydro facilities compared with fourth-quarter 2006 when water flows were above normal.

Operating income from Bruce Power in fourth-quarter 2007 was $43 million, a decrease of $16 million from fourth-quarter 2006. The decrease was due to lower power generation volumes and higher operating costs related to the significant increase in planned outage days at Bruce A as well as higher post-employment benefit costs and lower positive purchase price amortizations related to the expiry of power sales agreements. These negative impacts were partially offset by higher realized prices, higher power generation volumes and lower operating costs as a result of fewer planned outage days at Bruce B.

Natural Gas Storage operating income in fourth-quarter 2007 was $57 million, an increase of $27 million from fourth-quarter 2006 due primarily to income earned from the Edson facility, which commenced operation in December 2006. Operating income in fourth-quarter 2007 included a $15-million net unrealized gain from the changes in fair value of proprietary natural gas inventory, forward purchase contracts and forward sale contracts.

Corporate net earnings in fourth-quarter 2007 were $17 million compared to $11 million in the same period in 2006. The increase was due primarily to $26 million of favourable income tax adjustments arising from legislated Canadian corporate income tax changes in fourth-quarter 2007, compared to $12 million in income tax refunds and related interest in the same period in 2006. Gains on derivatives used to manage the Company's exposure to foreign exchange rate fluctuations and the impact of positive tax rate differentials also contributed to higher net earnings. However, these gains were more than offset by higher financial charges, resulting primarily from financing the acquisitions of ANR and additional interest in Great Lakes. Corporate's comparable expenses were $9 million in fourth-quarter 2007 compared with $1 million in the same period in 2006, excluding the favourable income tax adjustments in the two periods.

SHARE INFORMATION

At February 25, 2008, TransCanada had 541.4 million issued and outstanding common shares. In addition, there were 9.2 million outstanding options to purchase common shares, of which 6.2 million were exercisable as at February 25, 2008.

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 the years 2000 to 2007 is found under the heading "Eight-Year Financial Highlights" in the Supplementary Information section of the Company's Annual Report.

GLOSSARY OF TERMS

AGIA	Alaska Gasline Inducement Act
ANR	American Natural Resources Company and ANR Storage Company, collectively
ANR Pipeline	ANR Pipeline Company
APG	Aboriginal Pipeline Group
AUC	Alberta Utilities Commission
B.C.	British Columbia
Bbl/d	Barrels per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
BPC	BPC Generation Infrastructure Trust
Broadwater	Broadwater LNG project
Bruce A	Bruce Power A L.P.
Bruce B	Bruce Power L.P.
Bruce Power	Bruce A and Bruce B, collectively
Cacouna	Cacouna LNG project
Calpine	Calpine Corporation
Cameco	Cameco Corporation
CAPLA	Canadian Alliance of Pipeline Landowners' Associations
CPUC	California Public Utilities Commision
CrossAlta	CrossAlta Gas Storage & Services Ltd.
DRP	Dividend Reinvestment and Share Purchase Plan
EPCOR	EPCOR Utilities Inc.
EUB	Alberta Energy and Utilities Board
FCM	Forward Capacity Market
FEIS	Final Environmental Impact Statement
FERC	Federal Energy Regulatory Commission
Foothills	Foothills Pipe Lines Ltd.
FT	Firm transportation
GAAP	Generally accepted accounting principles
Gas Pacifico	Gasoducto del Pacifico S.A.
GJ	Gigajoule
GRA	General Rate Application
Great Lakes	Great Lakes Gas Transmission Limited Partnership
GTN	GTN System and North Baja, collectively
GTNC	Gas Transmission Northwest Corporation
GWh	Gigawatt hours
Halton Hills	Halton Hills Generating Station
INNERGY	INNERGY Holdings S.A.
Iroquois	Iroquois Gas Transmission System, L.P.
Keystone	Keystone Canada and Keystone U.S., collectively
Keystone Canada	TransCanada Keystone Pipeline Limited Partnership
Keystone U.S.	TransCanada Keystone Pipeline LP
km	Kilometres
LIBOR	London Interbank Offered Rate
LNG	Liquefied natural gas
MD&A	Management's Discussion and Analysis
MGP	Mackenzie Gas Pipeline
Mirant	Mirant Corporation and certain of its subsidiaries
mmcf/d	Million cubic feet per day
Moody's	Moody's Investors Service
MW	Megawatt
MWh	Megawatt hours
NEB	National Energy Board
Net earnings	Net income from continuing operations
NGL	Natural gas liquid
NGTL	NOVA Gas Transmission Ltd.
Northern Border	Northern Border Pipeline Company
NPA	Northern Pipeline Act of Canada
NW Natural	Northwest Natural Gas Company
OM&A	Operating, maintenance and administration
OPA	Ontario Power Authority
OSP	Ocean State Power
Paiton Energy	P.T. Paiton Energy Company
Palomar	Palomar Gas Transmission LLC
PG&E	Pacific Gas & Electric Company
PipeLines LP	TC PipeLines, LP
Portland	Portland Natural Gas Transmission System
Portlands Energy	Portlands Energy Centre L.P.
Power LP	TransCanada Power, L.P.
PPA	Power purchase arrangement
ROE	Rate of return on common equity
SEC	U.S. Securities and Exchange Commission
TCPL	TransCanada PipeLines Limited
TCPM	TransCanada Power Marketing Ltd.
TQM	Trans Québec & Maritimes System
TransCanada or the Company	TransCanada Corporation
TransGas	TransGas de Occidente S.A.
Tuscarora	Tuscarora Gas Transmission Company
U.S.	United States
Ventures LP	TransCanada Pipeline Ventures Limited Partnership
WCSB	Western Canada Sedimentary Basin

Report of Management

The consolidated financial statements included in this Annual Report are the responsibility of TransCanada Corporation's management 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 judgments. 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 Canadian GAAP. It compares the Company's financial performance in 2007 to that in 2006 and should be read in conjunction with the consolidated financial statements and accompanying notes. In addition, it highlights significant changes between 2006 and 2005.

Management has designed and maintains a system of internal accounting controls, including a program of internal audits. Management believes that these controls provide reasonable assurance that financial records are reliable and form a proper basis for preparation of financial statements. The internal accounting control process includes 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 control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. TransCanada acquired American Natural Resources Company and ANR Storage Company (collectively, ANR) in 2007 and began consolidating the operations of ANR into the Company. Management has excluded this business from its evaluation of the effectiveness of the Company's internal control over financial reporting as of December 31, 2007. The net income attributable to this business represented approximately nine per cent of the Company's consolidated net income for the year ended December 31, 2007, and their aggregate total assets represented approximately 12 per cent of the Company's consolidated total assets as at December 31, 2007.

Based on their evaluation, management concluded that internal control over financial reporting is effective as of December 31, 2007 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 unrelated, non-management directors. The Audit Committee meets at least six times a year with management and meets independently with each of 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 as set out in the Annual Information Form. The Audit Committee reviews 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 external auditors have free access to the Audit Committee without obtaining 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 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 Canadian 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 25, 2008

Auditors' Report

To the Shareholders of TransCanada Corporation

We have audited the consolidated balance sheets of TransCanada Corporation as at December 31, 2007 and 2006, 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, 2007. 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. With respect to the consolidated financial statements for the years ended December 31, 2007 and 2006, we also conducted our audits 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, 2007 and 2006 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2007 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada

February 25, 2008

TRANSCANADA CORPORATION
CONSOLIDATED INCOME

Year ended December 31 *(millions of dollars except per share amounts)*	**2007**	2006	2005
Revenues	**8,828**	7,520	6,124
Operating Expenses			
Plant operating costs and other	**3,030**	2,411	1,825
Commodity purchases resold	**1,959**	1,707	1,232
Depreciation	**1,179**	1,059	1,017
	6,168	5,177	4,074
	2,660	2,343	2,050
Other Expenses/(Income)			
Financial charges (Note 9)	**943**	825	836
Financial charges of joint ventures (Note 10)	**75**	92	66
Income from equity investments (Note 7)	**(17)**	(33)	(247)
Interest income and other	**(135)**	(123)	(63)
Gains on sales of assets (Note 8)	**(16)**	(23)	(445)
	850	738	147
Income from Continuing Operations before Income Taxes and Non-Controlling Interests	**1,810**	1,605	1,903
Income Taxes (Note 18)			
Current	**432**	301	550
Future	**58**	175	60
	490	476	610
Non-Controlling Interests (Note 15)	**97**	78	84
Net Income from Continuing Operations	**1,223**	1,051	1,209
Net Income from Discontinued Operations (Note 24)	**–**	28	–
Net Income	**1,223**	1,079	1,209
Net Income per Share (Note 16)			
Basic			
Continuing operations	**$2.31**	$2.15	$2.49
Discontinued operations	**–**	0.06	–
	$2.31	$2.21	$2.49
Diluted			
Continuing operations	**$2.30**	$2.14	$2.47
Discontinued operations	**–**	0.06	–
	$2.30	$2.20	$2.47

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)*	**2007**	2006	2005
Cash Generated from Operations			
Net income	**1,223**	1,079	1,209
Depreciation	**1,179**	1,059	1,017
Income from equity investments in excess of distributions received (Note 7)	**(1)**	(9)	(71)
Future income taxes (Note 18)	**58**	175	60
Non-controlling interests (Note 15)	**97**	78	84
Employee future benefits funding lower than/(in excess of) expense (Note 21)	**43**	(31)	(9)
Gains on sales of assets, net of current income taxes (Note 8)	**(14)**	(11)	(318)
Other	**36**	38	(21)
	2,621	2,378	1,951
Decrease/(increase) in operating working capital (Note 22)	**215**	(303)	(49)
Net cash provided by operations	**2,836**	2,075	1,902
Investing Activities			
Capital expenditures	**(1,651)**	(1,572)	(754)
Acquisitions, net of cash acquired (Note 8)	**(4,223)**	(470)	(1,317)
Disposition of assets, net of current income taxes (Note 8)	**35**	23	671
Deferred amounts and other	**(368)**	(97)	64
Net cash used in investing activities	**(6,207)**	(2,116)	(1,336)
Financing Activities			
Dividends on common shares (Note 16)	**(546)**	(617)	(586)
Distributions paid to non-controlling interests	**(88)**	(72)	(74)
Notes payable (repaid)/issued, net	**(46)**	(495)	416
Long-term debt issued	**2,631**	2,107	799
Reduction of long-term debt	**(1,088)**	(729)	(1,113)
Long-term debt of joint ventures issued	**142**	56	38
Reduction of long-term debt of joint ventures	**(157)**	(70)	(80)
Junior subordinated notes issued	**1,107**	–	–
Preferred securities redeemed	**(488)**	–	–
Common shares issued, net of issue costs (Note 16)	**1,711**	39	44
Partnership units of subsidiary issued (Note 8)	**348**	–	–
Net cash provided by/(used in) financing activities	**3,526**	219	(556)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(50)**	9	11
Increase in Cash and Cash Equivalents	**105**	187	21
Cash and Cash Equivalents			
Beginning of year	**399**	212	191
Cash and Cash Equivalents			
End of year	**504**	399	212

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)*	**2007**	2006
ASSETS		
Current Assets		
Cash and cash equivalents	**504**	399
Accounts receivable	**1,116**	1,004
Inventories	**497**	392
Other	**188**	297
	2,305	2,092
Long-Term Investments (Note 7)	**63**	71
Plant, Property and Equipment (Note 4)	**23,452**	21,487
Goodwill	**2,633**	281
Other Assets (Note 5)	**1,877**	1,978
	30,330	25,909
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable (Note 19)	**421**	467
Accounts payable	**1,767**	1,500
Accrued interest	**261**	264
Current portion of long-term debt (Note 9)	**556**	616
Current portion of long-term debt of joint ventures (Note 10)	**30**	142
	3,035	2,989
Deferred Amounts (Note 12)	**1,107**	1,029
Future Income Taxes (Note 18)	**1,179**	876
Long-Term Debt (Note 9)	**12,377**	10,887
Long-Term Debt of Joint Ventures (Note 10)	**873**	1,136
Junior Subordinated Notes (Note 11)	**975**	
Preferred Securities (Note 14)	**–**	536
	19,546	17,453
Non-Controlling Interests (Note 15)	**999**	755
Shareholders' Equity		
Common shares (Note 16)	**6,662**	4,794
Contributed surplus	**276**	273
Retained earnings	**3,220**	2,724
Accumulated other comprehensive income	**(373)**	(90)
	2,847	2,634
	9,785	7,701
Commitments, Contingencies and Guarantees (Note 23)		
Subsequent Events (Note 25)		
	30,330	25,909

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

On behalf of the Board:

Harold N. Kvisle
Director

Kevin E. Benson
Director

TRANSCANADA CORPORATION
CONSOLIDATED COMPREHENSIVE INCOME

Year ended December 31 *(millions of dollars)*	**2007**	2006	2005
Net Income	**1,223**	1,079	1,209
Other Comprehensive Income/(Loss), net of income taxes			
Change in foreign currency translation gains and losses on investments in foreign operations(1)	**(350)**	6	(34)
Change in gains and losses on hedges of investments in foreign operations(2)	**79**	(6)	15
Change in gains and losses on derivative instruments designated as cash flow hedges(3)	**42**	–	–
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods(4)	**42**	–	–
Other comprehensive income/(loss)	**(187)**	–	(19)
Comprehensive Income	**1,036**	1,079	1,190

(1) Net of income tax expense of $101 million in 2007 (2006 – $3-million expense; 2005 – $13-million expense).

(2) Net of income tax expense of $41 million in 2007 (2006 – $3-million recovery; 2005 – $8-million expense).

(3) Net of income tax expense of $27 million in 2007.

(4) Net of income tax expense of $23 million in 2007.

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 Adjustment	Cash Flow Hedges	Total
Balance at December 31, 2004	(71)	–	(71)
Change in foreign currency translation gains and losses on investments in foreign operations[1]	(34)	–	(34)
Change in gains and losses on hedges of investments in foreign operations[2]	15	–	15
Balance at December 31, 2005	(90)	–	(90)
Change in foreign currency translation gains and losses on investments in foreign operations[1]	6	–	6
Change in gains and losses on hedges of investments in foreign operations[2]	(6)	–	(6)
Balance at December 31, 2006	(90)	–	(90)
Transition adjustment resulting from adopting new financial instruments standards[3]	–	**(96)**	**(96)**
Change in foreign currency translation gains and losses on investments in foreign operations[1]	**(350)**	**–**	**(350)**
Change in gains and losses on hedges of investments in foreign operations[2]	**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][6]	**–**	**42**	**42**
Balance at December 31, 2007	**(361)**	**(12)**	**(373)**

(1) Net of income tax expense of $101 million in 2007 (2006 – $3-million expense; 2005 – $13-million expense).

(2) Net of income tax expense of $41 million in 2007 (2006 – $3-million recovery; 2005 – $8-million expense).

(3) Net of income tax expense of $44 million in 2007.

(4) Net of income tax expense of $27 million in 2007.

(5) Net of income tax expense of $23 million in 2007.

(6) The amount of gains and losses related to cash flow hedges reported in accumulated other comprehensive income that will be reclassified to net income in 2008 is not expected to be significant.

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)*	**2007**	2006	2005
Common Shares			
Balance at beginning of year	**4,794**	4,755	4,711
Proceeds from shares issued under public offering (Note 16)	**1,683**	–	–
Shares issued under dividend reinvestment plan (Note 16)	**157**	–	–
Proceeds from shares issued on exercise of stock options (Note 16)	**28**	39	44
Balance at end of year	**6,662**	4,794	4,755
Contributed Surplus			
Balance at beginning of year	**273**	272	270
Issuance of stock options (Note 16)	**3**	1	2
Balance at end of year	**276**	273	272
Retained Earnings			
Balance at beginning of year	**2,724**	2,269	1,655
Transition adjustment resulting from adopting new financial instruments accounting standards (Note 2)	**4**		
Net income	**1,223**	1,079	1,209
Common share dividends	**(731)**	(624)	(595)
Balance at end of year	**3,220**	2,724	2,269
Accumulated Other Comprehensive Income, Net of Income Taxes			
Balance at beginning of year	**(90)**	(90)	(71)
Transition adjustment resulting from adopting new financial instruments accounting standards (Note 2)	**(96)**		
Other comprehensive income/(loss)	**(187)**	–	(19)
Balance at end of year	**(373)**	(90)	(90)
Total Shareholders' Equity	**9,785**	7,701	7,206

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

TRANSCANADA CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

TransCanada Corporation (the Company or TransCanada) 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 owns and operates the following:

- a natural gas transmission system extending from the Alberta 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 Oklahoma, Texas, Louisiana and the Gulf of Mexico to markets located primarily in Wisconsin, Michigan, Illinois, Ohio and Indiana, and regulated natural gas storage facilities in Michigan (ANR);
- a natural gas transmission system extending from the British Columbia/Idaho border to the Oregon/California border, traversing Idaho, Washington and Oregon (GTN System);
- a natural gas transmission system extending from central Alberta to the British Columbia (B.C.)/United States border and to the Saskatchewan/U.S. border, and from the Alberta border west into southeastern B.C. (Foothills);
- a natural gas transmission system extending from a point near Ehrenberg, Arizona to the Baja California, Mexico/California border (North Baja);
- 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 (Ventures LP);
- a natural gas transmission system in Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi (Tamazunchale);
- a 53.6 per cent interest in a natural gas transmission system that connects to the Canadian Mainline and serves markets in Eastern Canada and northeastern and midwestern U.S. (Great Lakes);
- 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 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 32.1 per cent interest in TC PipeLines, LP (PipeLines LP), which owns the following:
  - a 46.4 per cent interest in Great Lakes, in which TransCanada has a 68.5 per cent effective ownership through PipeLines LP and direct interests;
  - 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), which TransCanada began operating in April 2007 and in which it has a 16.1 per cent effective ownership interest through PipeLines LP; and
  - 100 per cent of a natural gas transmission system extending from Malin, Oregon to Wadsworth, Nevada, (Tuscarora), which TransCanada operates and in which it has a 32.1 per cent effective ownership interest through PipeLines LP.

Pipelines also holds the Company's investments in other pipelines and pipeline projects including the following:

- 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, which extends from Mariquita in the central region of Colombia to Cali in the southwest of Colombia (TransGas);
- 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); and
- a 50 per cent interest in a pipeline under construction that will transport crude oil from Hardisty, Alberta, to U.S. Midwest markets at Wood River and Patoka in Illinois, and to Cushing, Oklahoma (Keystone).

Energy
The Energy segment builds, owns and operates electrical power generation plants, and sells electricity. Energy also holds investments in other electrical power generation plants, non-regulated natural gas storage facilities and interests in liquefied natural gas (LNG) regasification projects in North America. This business operates in Canada and the U.S. as follows:

Through its Energy segment, TransCanada owns and operates:

- 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);
- natural gas-fired cogeneration plants in Alberta at Carseland, Redwater, Bear Creek and MacKay River;
- a natural gas-fired cogeneration plant near Saint John, New Brunswick (Grandview);
- a waste-heat fuelled power plant at the Cancarb facility in Medicine Hat, Alberta (Cancarb);
- a natural gas-fired cogeneration plant near Trois-Rivières, Québec (Bécancour); and
- a natural gas storage facility near Edson, Alberta (Edson).

TransCanada owns but does not operate:

- a 48.7 per cent partnership interest and a 31.6 per cent partnership interest in the nuclear power generation facilities of Bruce Power A L.P. (Bruce A) and Bruce Power L.P. (Bruce B) (collectively Bruce Power), respectively, located near Lake Huron, Ontario;
- a 60 per cent interest in an underground natural gas storage facility near Crossfield, Alberta (CrossAlta); and
- a 62 per cent interest in the Baie-des-Sables and Anse-à-Valleau wind farms, two of six wind farms in Gaspé, Québec (Cartier Wind).

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 projects under construction as follow:

- a 62 per cent interest in Carleton, the third of the six wind farms in the Cartier Wind project;
- a 50 per cent interest in a combined-cycle natural gas cogeneration plant near downtown Toronto, Ontario (Portlands Energy); and
- a natural gas-fired, combined-cycle power plant near Toronto (Halton Hills).

NOTE 1 ACCOUNTING POLICIES

The consolidated financial statements of the Company have been prepared by Management in accordance with Canadian 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 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. In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized below.

Basis of Presentation
The consolidated financial statements include the accounts of TransCanada and its subsidiaries as well as its proportionate share of the accounts of its joint ventures. TransCanada uses the equity method of accounting for investments over which the Company is able to exercise significant influence. The Company consolidates its 32.1 per cent ownership interest in PipeLines LP and its 61.7 per cent interest in Portland Natural Gas Transmission System (Portland), with the other partners' interests included in Non-Controlling Interests.

Regulation
The Canadian Mainline, Foothills Pipe Lines Ltd. (Foothills), including the BC System effective April 1, 2007, and Trans Québec Maritimes System (TQM) are subject to the authority of the National Energy Board (NEB). Effective January 1, 2008, the Alberta System is regulated by the Alberta Utilities Commission (AUC), a new regulatory body created as a result of the reorganization of the Alberta Energy and Utilities

Board (EUB). The Alberta System was regulated by the EUB prior to this date. The GTN System and North Baja (collectively, GTN), ANR and the other natural gas pipelines in the U.S. are subject to the authority of the Federal Energy Regulatory Commission (FERC). These natural gas transmission operations are regulated with respect to the determination of revenues, tolls, construction and operations. 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 the Company's revenues and tolls, and to thereby achieve a proper matching of revenues and expenses. The impact of rate regulation on TransCanada is provided in Note 13 of these financial statements.

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 and AUC. Revenues from U.S. operations subject to rate regulation are recorded in accordance with FERC rules and regulations. Revenues from non-regulated operations are recorded when products have been delivered or services have been performed.

Energy

i) Power
The majority of revenues from the Power business are derived from the sale of electricity from energy marketing activities and from the sale of unutilized natural gas fuel, which are recorded in the month of delivery. Revenues also include the impact of energy derivative contracts, the accounting for which is described in Note 2.

ii) Natural Gas Storage
The majority of the revenues earned from natural gas storage are derived from providing storage services and are recognized in accordance with the terms of the 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, are recorded at fair value with changes in fair value recorded in Net Income.

Dilution Gains

Dilution gains resulting from the sale of units by partnerships in which TransCanada has an ownership interest are recognized immediately in net income.

Cash and Cash Equivalents

The Company's short-term investments with original maturities of three months or less are considered to be cash equivalents and are recorded at cost, which approximates market value.

Inventories

Inventories consisting of uranium and materials and supplies including spare parts, are carried at the lower of average cost or net realizable value. As a result of adopting the new Canadian Institute of Chartered Accountants (CICA) Handbook accounting requirements for Section 3031 "Inventories", effective April 1, 2007, TransCanada began valuing its proprietary natural gas inventory held in storage at its fair value, as measured by the one-month forward price for natural gas.

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. Pipeline and compression equipment are depreciated at annual rates ranging from two to six per cent and metering and other plant equipment are depreciated at various rates. An allowance for funds used during construction is capitalized based on the rate of return on rate base approved by regulators and included in the cost of gas transmission plant. Interest is capitalized during construction on non-regulated pipelines.

Energy
Major power generation and natural gas storage plant, equipment and structures in the Energy segment are recorded at cost and depreciated on a straight-line basis over estimated service lives at average annual rates ranging from two 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 or 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 plants 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.

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 values 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. Currently, all goodwill relates to U.S. Pipelines acquisitions.

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 a PPA are deferred and amortized on a straight-line basis over the term of the contract, which ranges from nine to 12 years. PPAs, under which TransCanada sells power, are accounted for as operating leases. A portion of these PPAs have been subleased to third parties under similar terms and conditions.

Stock Options

TransCanada's Stock Option Plan permits options to be awarded to certain employees, including officers, to purchase the Company's common shares. The contractual life of options granted after 2002 and options granted prior to 2003 is seven years and ten years, respectively. Options may be exercised at a price determined at the time the option is awarded and vest 33.3 per cent on each of the three following award date anniversaries. The Company records compensation expense over the three-year vesting period. This charge is reflected in the Pipelines and Energy segments. Upon exercise of stock options, amounts originally recorded against Contributed Surplus are reclassified to Common Shares.

Income Taxes

The taxes payable method of accounting for income taxes is used for tollmaking purposes in Canadian regulated natural gas transmission operations, as prescribed by regulators. It is not necessary to provide for future income taxes under the taxes payable method. As permitted by Canadian GAAP, this method is also used for accounting purposes, since there is reasonable expectation that future taxes payable will be included in future costs of service and recorded in revenues at that time. The liability method of accounting for income taxes is used for the remainder of the Company's operations. Under the liability method, future tax assets and liabilities are recognized 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 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 in which they occur.

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 the principal amounts of foreign currency debt related to the Alberta System, Foothills and Canadian Mainline are deferred until they are refunded or recovered in tolls.

Derivative Financial Instruments and Hedging Activities

The Company uses derivative 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. The methods the Company uses to account for its derivative and other financial instruments are described in Notes 2 and 17.

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.

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 if 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.

It is not possible to determine the scope and timing of asset retirements related to regulated natural gas transmission pipelines and, therefore, not possible to make a reasonable estimate of the fair value of the associated liability. As a result, the Company has not recorded an amount for asset retirement obligations related to these assets, with the exception of abandoned facilities. Management believes it is reasonable to assume that all retirement costs associated with its regulated pipelines will be recovered through tolls in future periods.

Similarly, it is not possible to determine the scope and timing of asset retirements related to hydroelectric power plants and, therefore, not possible to make a reasonable estimate of the fair value of the associated liability. As a result, the Company has not recorded an amount for asset retirement obligations related to hydroelectric power plant assets. With respect to the nuclear assets leased by Bruce Power, the Company has not recorded an amount for asset retirement obligations, as the lessor is responsible for decommissioning liabilities under the lease agreement.

Employee Benefit and Other Plans

The Company sponsors defined benefit pension plans (DB Plans), defined contributions plans (DC Plans) and other post-employment plans. Contributions made by the Company to the DC Plans are expensed as incurred. The cost of the DB Plans and other post-employment benefits earned 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 ages 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 plan 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 10 per cent of the greater of the benefit obligation and the fair value of the DB Plans' assets 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 broad-based, medium-term employee incentive plans, which grant units to each eligible employee and are payable in cash. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, units 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 2 ACCOUNTING CHANGES

Changes in Accounting Policies for 2007

Effective January 1, 2007, the Company adopted the accounting requirements for CICA Handbook Sections 1506 "Accounting Changes", 1530 "Comprehensive Income", 3251 "Equity", 3855 "Financial Instruments – Recognition and Measurement", and 3865 "Hedges". In addition, the Company chose to adopt the accounting requirements for Sections 3862 "Financial Instruments – Disclosure", 3863 "Financial Instruments – Presentation", and 1535 "Capital Disclosures" effective December 31, 2007, as well as the accounting requirements for Section 3031 "Inventories" effective April 1, 2007. Adjustments to the consolidated financial statements for 2007 have been made in accordance with the transitional provisions for these new standards.

Comprehensive Income and Equity

The Company's financial statements include statements of Consolidated Comprehensive Income and Consolidated Accumulated Other Comprehensive Income. In addition, as required in CICA Handbook Section 3251, the Company now presents separately, in the Consolidated Shareholders' Equity statement, the changes for each of its components of Shareholders' Equity, including Accumulated Other Comprehensive Income.

Financial Instruments

All financial instruments must initially be included 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 financial assets and liabilities consist of swaps, options, forwards and futures, and are entered into with the intention of generating a profit. A financial asset or liability that does not meet this criterion may also be designated as held for trading. Power and natural gas held-for-trading 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 held-for-trading instruments are recorded in Financial Charges and in Interest Income and Other, respectively. The Company had not designated any financial assets or liabilities as held for trading at December 31, 2007.

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. TransCanada's available-for-sale financial instruments include fixed-income securities held for self-insurance. These instruments are initially accounted for 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 will be included in Interest Income and Other.

Held-to-maturity financial assets are accounted for at their amortized cost using the effective interest method. The Company did not have any held-to-maturity financial assets at December 31, 2007.

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 net of any impairment. Loans and receivables include primarily trade accounts receivable and non-interest-bearing third-party loans 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. Interest expense is included in Financial Charges and in Financial Charges of Joint Ventures. Items in this financial instrument category are recognized at amortized cost using the effective interest method.

All derivatives are recorded on the balance sheet at fair value, with the exception of those 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 (normal purchase and normal sale exemption). Changes in the 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 under the heading Hedges in this Note.

Derivatives embedded in other financial instruments or contracts (the 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 derivates that are recorded separately are included in Revenues. The Company used January 1, 2003 as the transition date for embedded derivatives.

Transaction costs are incremental costs that are directly attributable to the acquisition, issue or disposal of a financial instrument. Effective January 1, 2007, the Company began offsetting long-term debt transaction costs against the associated debt and began amortizing these costs using the effective interest method. Previously, these costs were amortized on a straight-line basis over the life of the debt. There was no material impact on the Company's financial statements as a result of this change in policy. In 2007, the impact on Net Income for the amortization of transaction costs using the effective interest method was nominal.

The Company records the fair values of material joint and several guarantees. These fair values cannot be readily obtained from an open market and therefore, 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 in Deferred Amounts.

Hedges

CICA Handbook Section 3865 specifies the criteria that must be satisfied in order to apply hedge accounting and the accounting for each of the permitted hedging strategies, including: fair value hedges, cash flow hedges and hedges of foreign currency exposures of net investments in self-sustaining foreign operations. Hedge accounting is discontinued prospectively when the derivative no longer qualifies as an effective hedge or is terminated or sold, or upon the sale or early termination of the hedged item.

Documentation must be prepared at the inception of the hedging arrangement in order to qualify for hedge accounting treatment. In addition, the Company must perform an assessment of effectiveness at inception of the contract and at each reporting date.

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 is also recorded in Net Income. Changes in the fair value of foreign exchange and interest rate hedges are recorded in Interest Income and Other and Financial Charges, 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 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 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. The gains and losses arising from the changes in 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 recognized in Net Income in the event the Company settles or otherwise reduces its investment.

Net Effect of Accounting Policy Changes

The net effect of the preceding accounting policy changes on the Company's financial statements at January 1, 2007, was as follows:

Increases/(decreases) (millions of dollars)	
Other current assets	(127)
Other assets	(203)
Accounts payable	(29)
Deferred amounts	(75)
Future income taxes	(42)
Long-term debt	(85)
Long-term debt of joint ventures	(7)
Accumulated other comprehensive income	(96)
Retained earnings	4

The primary changes in 2007 to the Company's accounting policies for financial instruments related to the requirements to record certain non-financial contracts at their fair value and to offset transaction costs against long-term debt.

Section 3862 Financial Instruments – Disclosures and Section 3863 Financial Instruments – Presentation

CICA Handbook Sections 3862 "Financial Instruments – Disclosure" and 3863 "Financial Instruments – Presentation", which replaced Section 3861 "Financial Instruments – Disclosure and Presentation", are effective January 1, 2008. However, the Company chose to adopt these standards effective December 31, 2007. The additional disclosure necessary to comply with these standards is provided in these consolidated financial statements. Certain information related to comparative years is not prescribed by these standards and accordingly has not been presented.

Section 1535 Capital Disclosures

CICA Handbook Section 1535 "Capital Disclosures" is effective for fiscal years beginning on or after October 1, 2007, however, TransCanada chose to adopt this standard effective December 31, 2007. Note 17 in these consolidated financial statements provides qualitative disclosure regarding objectives, policies and processes for managing capital as well as quantitative data on capital as of December 31, 2007.

Proprietary Natural Gas Inventories and Revenue Recognition

CICA Handbook Section 3031 "Inventories" is effective January 1, 2008. However, the Company chose to adopt this standard effective April 1, 2007, and began valuing its proprietary natural gas inventory held in storage at fair value, as measured by the one-month forward price for natural gas. 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. TransCanada did not have any proprietary natural gas inventory prior to April 1, 2007.

The Company records its proprietary natural gas storage results in Revenues net of Commodity Purchases Resold. All changes in the fair value of the proprietary natural gas inventories are reflected in Inventories and Revenues.

Future Accounting Changes

Rate-Regulated Operations

Effective January 1, 2009, the temporary exemption from CICA Handbook Section 1100, "Generally Accepted Accounting Principles", which permits the recognition and measurement of assets and liabilities arising from rate regulation, will be withdrawn. In addition, Section 3465 "Income Taxes" was amended to require the recognition of future income tax liabilities and assets. As a result of the changes, TransCanada will be required to recognize future income tax liabilities and assets instead of using the taxes payable method, and will record an offsetting adjustment to regulatory assets and liabilities. If the liability method of accounting had been used at December 31, 2007, additional future income tax liabilities in the amount of $1,138 million would have been recorded and would have been recoverable from future revenue. These changes will be applied prospectively beginning January 1, 2009.

International Financial Reporting Standards

The CICA's Accounting Standards Board (AcSB) announced that Canadian publicly accountable enterprises will adopt International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. IFRS will require increased financial statement disclosure. Although IFRS uses a conceptual framework similar to Canadian GAAP, differences in accounting policies will need to be addressed. TransCanada is currently assessing the impact of this AcSB announcement on its financial statements.

Intangible Assets

The CICA Handbook implemented revisions to standards dealing with Intangible Assets effective for fiscal years beginning on or after October 1, 2008. The revisions are intended to align the definition of an Intangible Asset in Canadian GAAP with that in IFRS and U.S. GAAP. Section 1000 "Financial Statement Concepts" was revised to remove material that permitted the recognition of assets that might not otherwise meet the definition of an asset and to add guidance from the IASB's "Framework for the Preparation and Presentation of Financial Statements" that will help distinguish assets from expenses. Section 3064 "Goodwill and Intangible Assets", which replaced Section 3062 "Goodwill and Other Intangible Assets", gives guidance on the recognition of intangible assets as well as the recognition and measurement of internally developed intangible assets. Section 3450 "Research and Development Costs" will be withdrawn from the Handbook. The Company does not expect these changes to have a material effect on its financial statements.

NOTE 3 SEGMENTED INFORMATION

NET INCOME/(LOSS)[1]

Year ended December 31, 2007 (millions of dollars)	**Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	**4,712**	**4,116**	**–**	**8,828**
Plant operating costs and other	**(1,670)**	**(1,353)**	**(7)**	**(3,030)**
Commodity purchases resold	**(72)**	**(1,887)**	**–**	**(1,959)**
Depreciation	**(1,021)**	**(158)**	**–**	**(1,179)**
	1,949	**718**	**(7)**	**2,660**
Financial charges and non-controlling interests	**(793)**	**1**	**(248)**	**(1,040)**
Financial charges of joint ventures	**(52)**	**(23)**	**–**	**(75)**
Income from equity investments	**17**	**–**	**–**	**17**
Interest income and other	**35**	**10**	**90**	**135**
Gain on sale of assets	**–**	**16**	**–**	**16**
Income taxes	**(470)**	**(208)**	**188**	**(490)**
Net Income	**686**	**514**	**23**	**1,223**

Year ended December 31, 2006 (millions of dollars)	Pipelines	Energy	Corporate	Total
Revenues	3,990	3,530	–	7,520
Plant operating costs and other	(1,380)	(1,024)	(7)	(2,411)
Commodity purchases resold	–	(1,707)	–	(1,707)
Depreciation	(927)	(131)	(1)	(1,059)
	1,683	668	(8)	2,343
Financial charges and non-controlling interests	(767)	–	(136)	(903)
Financial charges of joint ventures	(69)	(23)	–	(92)
Income from equity investments	33	–	–	33
Interest income and other	67	5	51	123
Gain on sale of assets	23	–	–	23
Income taxes	(410)	(198)	132	(476)
Net income from continuing operations	560	452	39	1,051
Net income from discontinued operations				28
Net Income				1,079

Year ended December 31, 2005 (millions of dollars)	Pipelines	Energy	Corporate	Total
Revenues	3,993	2,131	–	6,124
Plant operating costs and other	(1,226)	(595)	(4)	(1,825)
Commodity purchases resold	–	(1,232)	–	(1,232)
Depreciation	(932)	(85)	–	(1,017)
	1,835	219	(4)	2,050
Financial charges and non-controlling interests	(788)	(2)	(130)	(920)
Financial charges of joint ventures	(57)	(9)	–	(66)
Income from equity investments	79	168	–	247
Interest income and other	25	5	33	63
Gains on sales of assets	82	363	–	445
Income taxes	(497)	(178)	65	(610)
Net Income	679	566	(36)	1,209

[1] Certain expenses such as indirect financial charges and related income taxes are not allocated to business segments when determining their net income.

TOTAL ASSETS

December 31 (millions of dollars)	2007	2006
Pipelines	22,024	18,320
Energy	7,037	6,500
Corporate	1,269	1,089
	30,330	25,909

GEOGRAPHIC INFORMATION

Year ended December 31 (millions of dollars)	2007	2006	2005
Revenues[1]			
Canada – domestic	5,019	4,956	3,499
Canada – export	1,006	972	1,160
United States and other	2,803	1,592	1,465
	8,828	7,520	6,124

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

December 31 (millions of dollars)	2007	2006
Plant, Property and Equipment		
Canada	16,741	16,204
United States	6,564	5,109
Mexico	147	174
	23,452	21,487

CAPITAL EXPENDITURES

Year ended December 31 (millions of dollars)	2007	2006	2005
Pipelines	564	560	244
Energy	1,079	976	506
Corporate	8	36	4
	1,651	1,572	754

NOTE 4 PLANT, PROPERTY AND EQUIPMENT

	2007			2006		
December 31 (millions of dollars)	**Cost**	**Accumulated Depreciation**	**Net Book Value**	Cost	Accumulated Depreciation	Net Book Value
Pipelines						
Canadian Mainline						
Pipeline	**8,889**	**4,149**	**4,740**	8,850	3,911	4,939
Compression	**3,371**	**1,303**	**2,068**	3,343	1,181	2,162
Metering and other	**345**	**140**	**205**	346	136	210
	12,605	**5,592**	**7,013**	12,539	5,228	7,311
Under construction	**28**	**–**	**28**	23	–	23
	12,633	**5,592**	**7,041**	12,562	5,228	7,334
Alberta System						
Pipeline	**5,258**	**2,504**	**2,754**	5,120	2,352	2,768
Compression	**1,522**	**842**	**680**	1,510	760	750
Metering and other	**831**	**297**	**534**	806	271	535
	7,611	**3,643**	**3,968**	7,436	3,383	4,053
Under construction	**120**	**–**	**120**	98	–	98
	7,731	**3,643**	**4,088**	7,534	3,383	4,151
ANR[1]						
Pipeline	**772**	**25**	**747**			
Compression	**424**	**32**	**392**			
Metering and other	**483**	**6**	**477**			
	1,679	**63**	**1,616**			
Under construction	**69**	**–**	**69**			
	1,748	**63**	**1,685**			
GTN						
Pipeline	**1,181**	**134**	**1,047**	1,386	111	1,275
Compression	**436**	**39**	**397**	512	32	480
Metering and other	**81**	**3**	**78**	89	–	89
	1,698	**176**	**1,522**	1,987	143	1,844
Under construction	**31**	**–**	**31**	17	–	17
	1,729	**176**	**1,553**	2,004	143	1,861
Great Lakes[2]						
Pipeline	**977**	**427**	**550**	806	463	343
Compression	**359**	**75**	**284**	255	85	170
Metering and other	**165**	**50**	**115**	122	52	70
	1,501	**552**	**949**	1,183	600	583
Under construction	**8**	**–**	**8**	4	–	4
	1,509	**552**	**957**	1,187	600	587
Foothills						
Pipeline	**903**	**476**	**427**	815	405	410
Compression	**632**	**286**	**346**	377	141	236
Metering and other	**112**	**57**	**55**	72	35	37
	1,647	**819**	**828**	1,264	581	683
Joint Ventures and Other						
Northern Border[3]	**1,232**	**528**	**704**	1,451	585	866
Other	**1,863**	**439**	**1,424**	2,274	615	1,659
	3,095	**967**	**2,128**	3,725	1,200	2,525
	30,092	**11,812**	**18,280**	28,276	11,135	17,141
Energy[4]						
Nuclear[5]	**1,479**	**286**	**1,193**	1,349	214	1,135
Natural gas	**1,570**	**383**	**1,187**	1,636	383	1,253
Hydro	**503**	**28**	**475**	592	21	571
Natural gas storage	**358**	**33**	**325**	344	22	322
Wind	**288**	**6**	**282**	131	–	131
Other	**137**	**78**	**59**	153	72	81
	4,335	**814**	**3,521**	4,205	712	3,493
Under construction	**1,606**	**–**	**1,606**	809	–	809
	5,941	**814**	**5,127**	5,014	712	4,302
Corporate	**60**	**15**	**45**	65	21	44
	36,093	**12,641**	**23,452**	33,355	11,868	21,487

(1) TransCanada acquired ANR on February 22, 2007.

(2) In February 2007, PipeLines LP acquired a 46.4 per cent general partnership interest in Great Lakes and TransCanada increased its ownership interest in Great Lakes by 3.6 per cent, bringing the Company's direct ownership to 53.6 per cent (December 31, 2006 – 50 per cent) and making Great Lakes a controlled entity. The Company commenced consolidating its investment in Great Lakes on a prospective basis. Prior to this, Great Lakes was being proportionately consolidated. TransCanada's 32.1 per cent ownership interest in PipeLines LP brought its effective ownership of Great Lakes, net of non-controlling interests, to 68.5 per cent at December 31, 2007.

(3) In April 2006, PipeLines LP acquired an additional 20 per cent general partnership interest in Northern Border, bringing its total general partnership interest to 50 per cent. Through TransCanada's ownership interest in PipeLines LP, Northern Border became a jointly controlled entity and TransCanada commenced proportionately consolidating its investment in Northern Border on a prospective basis. TransCanada's effective ownership of Northern Border, net of non-controlling interests, was 16.1 per cent at December 31, 2007 (2006 – 6.7 per cent).

(4) Certain power generation facilities with long-term PPAs are accounted for as assets under operating leases. The net book value of these facilities was $78 million at December 31, 2007 (2006 – $81 million). Revenues of $16 million were recognized in 2007 (2006 – $13 million) through the sale of electricity under the related PPAs.

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

NOTE 5 OTHER ASSETS

December 31 (millions of dollars)	**2007**	2006
PPAs[1]	**709**	767
Regulatory assets	**336**	178
Pension and other benefit plans	**234**	268
Fair value of derivative contracts	**204**	144
Loans and advances[2]	**141**	121
Deferred project development costs[3]	**40**	70
Hedging deferrals[4]	**–**	152
Debt issue costs[5]	**–**	77
Other	**213**	201
	1,877	1,978

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

December 31 (millions of dollars)	**2007 Cost**	**2007 Accumulated Amortization**	**2007 Net Book Value**	2006 Cost	2006 Accumulated Amortization	2006 Net Book Value
PPAs	**915**	**206**	**709**	915	148	767

The amortization expense for the PPAs was $58 million for the year ended December 31, 2007 (2006 – $58 million; 2005 – $24 million). The expected annual amortization expense in each of the next five years is: 2008 – $58 million; 2009 – $58 million; 2010 – $58 million; 2011 – $57 million; and 2012 – $57 million.

(2) The balance at December 31, 2007 included a $137-million loan (2006 – $118 million) to the Aboriginal Pipeline Group (APG) to finance the APG for its one-third share of project development costs related to the Mackenzie Gas Pipeline project. The ability to recover this investment remains dependent upon the successful outcome of the project.

(3) The balance at December 31, 2007 included $40 million (2006 – $31 million) related to the Broadwater LNG project. The balance at December 31, 2006 included $39 million related to Keystone.

(4) Changes in GAAP required the Company to record the effective portion and the changes in fair value of cash flow and fair value hedges in Other Comprehensive Income and Net Income, respectively, effective January 1, 2007. Prior to this date, the fair value of certain hedges was deferred and recognized in income when the instrument had settled.

(5) Changes in GAAP required the Company to offset long-term debt transaction costs against the associated debt, effective January 1, 2007.

NOTE 6 JOINT VENTURE INVESTMENTS

		TransCanada's Proportionate Share				
		Income Before Income Taxes Year ended December 31			Net Assets December 31	
(millions of dollars)	Ownership Interest[1]	**2007**	2006	2005	**2007**	2006
Pipelines						
Northern Border	[3]	**63**	47	–	**542**	634
Iroquois	44.5%[4]	**25**	25	29	**163**	194
Great Lakes	[5]	**13**	69	73	**–**	370
TQM	50.0%	**11**	11	13	**74**	75
Keystone	50.0%[6]	**–**	–	–	**207**	–
Other	Various	**13**	6	10	**48**	–
Energy						
Bruce A	48.7%[7]	**8**	75	19	**1,640**	916
Bruce B	31.6%[7]	**140**	140	5	**325**	425
CrossAlta[2]	60.0%	**59**	64	31	**38**	36
Cartier Wind	62.0%[8]	**10**	2	–	**275**	172
TC Turbines	50.0%	**5**	5	5	**29**	26
Portlands Energy	50.0%	**–**	–	–	**269**	90
ASTC Power Partnership	50.0%[9]	**–**	–	–	**76**	82
Power LP	[10]	**–**	–	25	**–**	–
		347	444	210	**3,686**	3,020

(1) All ownership interests are as at December 31, 2007.

(2) CrossAlta Gas Storage & Services Ltd. (CrossAlta).

(3) PipeLines LP acquired an additional 20 per cent general partnership interest in Northern Border in April 2006, increasing its general partnership interest to 50 per cent. Through TransCanada's 32.1 per cent ownership interest in PipeLines LP, Northern Border became a jointly controlled entity and TransCanada commenced proportionately consolidating its investment in Northern Border on a prospective basis. The Company's effective ownership of Northern Border, net of non-controlling interests, was 16.1 per cent at December 31, 2007 (2006 – 6.7 per cent).

(4) The Company acquired an additional 3.5 per cent ownership interest in Iroquois Gas Transmission System, L.P. (Iroquois) in June 2005.

(5) In February 2007, TransCanada acquired an additional 3.6 per cent interest in Great Lakes, bringing its direct ownership interest to 53.6 per cent, and PipeLines LP acquired a 46.4 per cent interest in Great Lakes, giving TransCanada an indirect 14.9 per cent interest in Great Lakes. As a result of these transactions the Company's effective ownership of Great Lakes, net of non-controlling interests, was 68.5 per cent at December 31, 2007 (2006 – 50 per cent). TransCanada commenced consolidating its investment in Great Lakes, on a prospective basis, effective February 22, 2007.

(6) In December 2007, ConocoPhillips exercised its option to become a 50 per cent partner with TransCanada in Keystone. As a result, TransCanada transferred $207 million of net assets and ConocoPhillips contributed $207 million of cash to each become a 50 per cent joint venture partner in Keystone.

(7) TransCanada acquired a 47.4 per cent ownership interest in Bruce A on October 31, 2005. The Company's ownership interest in Bruce A was 48.7 per cent at December 31, 2007 (2006 – 48.7 per cent). The Company proportionately consolidated its investments in Bruce A and Bruce B on a prospective basis, effective October 31, 2005.

(8) TransCanada proportionately consolidates 62 per cent of the Cartier Wind assets. The first two phases of the six-phase Cartier Wind project, Baie-des-Sables and Anse-à-Valleau, began operating in November 2006 and 2007, respectively.

(9) The Company has a 50 per cent ownership interest in ASTC Power Partnership, which is located in Alberta and holds the Sundance B PPA. The underlying power volumes related to this ownership interest are effectively transferred to TransCanada.

(10) In August 2005, the Company sold its 30.6 per cent interest in TransCanada Power, L.P.

Summarized Financial Information of Joint Ventures

Year ended December 31 (millions of dollars)	**2007**	2006	2005
Income			
Revenues	**1,224**	1,379	687
Plant operating costs and other	**(659)**	(689)	(328)
Depreciation	**(150)**	(162)	(93)
Financial charges and other	**(68)**	(84)	(56)
Proportionate share of joint venture income before income taxes	**347**	444	210

Year ended December 31 (millions of dollars)	**2007**	2006	2005
Cash Flows			
Operating activities	**420**	645	346
Investing activities	**(761)**	(641)	(133)
Financing activities[1]	**409**	(31)	(152)
Effect of foreign exchange rate changes on cash and cash equivalents	**(8)**	9	(1)
Proportionate share of increase/(decrease) in cash and cash equivalents of joint ventures	**60**	(18)	60

[1] Financing activities included cash outflows resulting from distributions paid to TransCanada of $361 million in 2007 (2006 – $470 million; 2005 – $201 million) and cash inflows resulting from capital contributions paid by TransCanada of $771 million in 2007 (2006 – $452 million; 2005 – $92 million).

December 31 (millions of dollars)	**2007**	2006
Balance Sheet		
Cash and cash equivalents	**170**	127
Other current assets	**314**	304
Plant, property and equipment	**4,283**	4,110
Other assets	**44**	78
Current liabilities	**(250)**	(443)
Long-term debt	**(873)**	(1,136)
Future income taxes	**(2)**	(20)
Proportionate share of net assets of joint ventures	**3,686**	3,020

NOTE 7 LONG-TERM INVESTMENTS

		TransCanada's Share							
		Distributions from Equity Investments Year ended December 31			Income from Equity Investments Year ended December 31			Equity Investments December 31	
(millions of dollars)	Ownership Interest	**2007**	2006	2005	**2007**	2006	2005	**2007**	2006
Pipelines									
TransGas	46.5%	**8**	7	6	**14**	11	11	**63**	66
Northern Border	(1)	**–**	13	76	**–**	13	61	**–**	–
Other	Various	**8**	4	10	**3**	9	7	**–**	5
Energy									
Bruce B	31.6%(2)	**–**	–	84	**–**	–	168	**–**	–
		16	24	176	**17**	33	247	**63**	71

(1) PipeLines LP acquired an additional 20 per cent general partnership interest in Northern Border in April 2006, bringing its general partnership interest to 50 per cent. Through TransCanada's 32.1 per cent ownership interest in PipeLines LP, Northern Border became a jointly controlled entity and TransCanada commenced proportionately consolidating its investment in Northern Border on a prospective basis.

(2) The Company commenced proportionately consolidating its 31.6 per cent ownership interest in Bruce B on a prospective basis, effective October 31, 2005.

NOTE 8 ACQUISITIONS AND DISPOSITIONS

Acquisitions

Pipelines

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 Gas Transmission Limited Partnership (Great Lakes) for a total of US$3.4 billion, subject to certain post-closing adjustments, 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 in the Pipelines segment after the acquisition date. The preliminary allocation of the purchase price at December 31, 2007, was 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	1,914	32	1,946
Current liabilities	(179)	(3)	(182)
Long-term debt	(475)	(16)	(491)
Other non-current liabilities	(326)	(19)	(345)
	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, subject to certain post-closing adjustments, 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 in the Pipelines segment after the acquisition date. The preliminary allocation of the purchase price at December 31, 2007, was 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 preliminary 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 values.

Factors that contributed to goodwill included the opportunity to expand 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 Private Placement Offering
PipeLines LP completed a private placement offering of 17,356,086 common units at a price of US$34.57 per unit in February 2007. 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 increased to 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 a 46.4-per-cent ownership interest in Great Lakes.

Tuscarora
PipeLines LP exercised its option to purchase Sierra Pacific Resources' remaining one per cent interest in Tuscarora Gas Transmission Company (Tuscarora) for US$2 million in December 2007. In addition, PipeLines LP purchased TransCanada's one per cent interest in Tuscarora for US$2 million.

In December 2006, PipeLines LP acquired an additional 49 per cent controlling general partner interest in Tuscarora for US$100 million in addition to indirectly assuming US$37 million of debt. The purchase price was allocated US$79 million to Goodwill, US$37 million to long-term debt, and the balance primarily to Plant, Property and Equipment. Factors that contributed to goodwill included opportunities for expansion and a stronger competitive position. The goodwill recognized on this transaction is amortizable for tax purposes. PipeLines LP began consolidating its investment in Tuscarora in December 2006. TransCanada became the operator of Tuscarora in December 2006 as a result of this transaction.

PipeLines LP now owns 100 per cent of Tuscarora. At December 31, 2007, TransCanada's 32.1 per cent ownership interest in PipeLines LP (December 31, 2006 – 13.4 per cent) gave it an effective ownership in Tuscarora of 32.1 per cent, net of non-controlling interests (December 31, 2006 – 14.3 per cent).

Northern Border
In April 2006, PipeLines LP acquired an additional 20 per cent general partnership interest in Northern Border Pipeline Company (Northern Border) for US$307 million, in addition to indirectly assuming US$122 million of debt. The purchase price was allocated US$114 million to Goodwill, US$122 million to long-term debt and the balance primarily to Plant, Property and Equipment. Factors that contributed to goodwill included opportunities for expansion and a stronger competitive position. The goodwill recognized on this transaction is amortizable for tax purposes.

PipeLines LP now owns 50 per cent of Northern Border. At December 31, 2007, TransCanada's 32.1 per cent ownership interest in PipeLines LP (2006 – 13.4 per cent) gave it an effective ownership in Northern Border of 16.1 per cent, net of non-controlling interests (2006 – 6.7 per cent). TransCanada proportionately consolidated its interest in Northern Border since the date of acquisition. TransCanada became the operator of Northern Border in April 2007 as a result of this transaction.

Energy

Sheerness PPA
TransCanada obtained the 756 MW Sheerness PPA from the Alberta Balancing Pool for $585 million effective December 31, 2005. The PPA terminates in 2020.

Bruce Power
In October 2005, TransCanada acquired an interest in Bruce A, a newly created partnership, as part of an agreement to restart Bruce A Units 1 and 2, which are currently idle. Under the Bruce A Sublease agreement, the new partnership subleased Units 1 to 4 from Bruce B and purchased certain other related assets. TransCanada incurred a net cash outlay of $100 million related to this transaction. As part of the reorganization, Bruce A and Bruce B became jointly controlled entities and TransCanada commenced proportionately consolidating its investment in both on a prospective basis effective October 31, 2005. At December 31, 2007 and 2006, the Company held a 48.7 per cent interest in Bruce A and a 31.6 per cent interest in Bruce B.

TC Hydro
TransCanada acquired TC Hydro, the hydroelectric generation assets of USGen New England, Inc. for approximately US$503 million in April 2005. Substantially all of the purchase price was allocated to Plant, Property and Equipment.

Dispositions

Pre-tax gains on sales of assets were as follow:

Year ended December 31 (millions of dollars)	**2007**	2006	2005
Gain on sale of land	**16**	–	–
Gain on sale of Northern Border Partners, LP interest	**–**	23	–
Gains related to Power LP	**–**	–	245
Gain on sale of Paiton Energy	**–**	–	118
Gain on sale of PipeLines LP units	**–**	–	82
	16	23	445

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

Northern Border Partners, LP Interest
In April 2006, TransCanada sold its 17.5 per cent general partner interest in Northern Border Partners, LP, generating net proceeds of $33 million (US$30 million) and recognizing an after-tax gain of $13 million. The net gain was recorded in the Pipelines segment and the Company recorded a $10-million income tax charge on the transaction, including $12 million of current income tax expense.

Power LP
In August 2005, TransCanada sold its ownership interest in TransCanada Power, L.P. (Power LP) to EPCOR Utilities Inc. (EPCOR), generating net proceeds of $523 million and realizing an after-tax gain of $193 million. The net gain was recorded in the Energy segment and the Company recorded a $52-million income tax charge on the transaction, including $79 million of current income tax expense. The sale resulted in disposal of Power LP assets and liabilities with a book value of $452 million and $174 million, respectively. EPCOR's acquisition included 14.5 million limited partnership units of Power LP, representing 30.6 per cent of the outstanding units, 100 per cent ownership of the general partner of Power LP, and the management and operations agreements governing the ongoing operation of Power LP's assets.

Paiton Energy
In November 2005, TransCanada sold its ownership interest of approximately 11 per cent in PT Paiton Energy Company (Paiton Energy) to subsidiaries of The Tokyo Electric Power Company for gross proceeds of $122 million (US$103 million) and recognized an after-tax gain of $115 million. The net gain was recorded in the Energy segment and the Company recorded a $3-million income tax charge, including $3 million of current income tax recovery.

TC PipeLines, LP
In March and April 2005, TransCanada sold a total of 3,574,200 common units of PipeLines LP for net proceeds of $153 million and recorded an after-tax gain of $49 million. The net gain was recorded in the Pipelines segment and the Company recorded a $33-million income tax charge on the transaction, including $51 million of current income tax expense.

NOTE 9 LONG-TERM DEBT

		2007		2006	
Outstanding loan amounts (millions of dollars unless otherwise indicated)	Maturity Dates	**Outstanding December 31**	**Interest Rate[1][2]**	Outstanding December 31	Interest Rate[2][3]
TRANSCANADA PIPELINES LIMITED					
First Mortgage Pipe Line Bonds					
Pounds sterling (2006 – £25 million)		**–**		57	16.5%
Debentures					
Canadian dollars	2008 to 2020	**1,351**	**10.9%**	1,355	10.9%
U.S. dollars (2007 and 2006 – US$600)[4]	2012 to 2021	**594**	**9.5%**	699	9.5%
Medium-Term Notes					
Canadian dollars[5]	2008 to 2031	**3,413**	**6.1%**	3,848	6.0%
Senior Unsecured Notes					
U.S. dollars (2007 – US$3,223; 2006 – US$2,223)[6]	2009 to 2037	**3,161**	**6.0%**	2,590	5.8%
		8,519		8,549	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian dollars	2008 to 2024	**501**	**11.6%**	564	11.6%
U.S. dollars (2007 and 2006 – US$375)	2012 to 2023	**368**	**8.2%**	437	8.2%
Medium-Term Notes					
Canadian dollars	2008 to 2030	**607**	**7.2%**	609	7.1%
U.S. dollars (2007 and 2006 – US$33)	2026	**32**	**7.5%**	38	7.5%
		1,508		1,648	
TRANSCANADA PIPELINE USA LTD.					
Bank Loan					
U.S. dollars (2007 – US$860)	2012	**850**	**5.7%**		
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. dollars (2007– US$444)	2010 to 2025	**435**	**9.1%**		
GAS TRANSMISSION NORTHWEST CORPORATION					
Senior Unsecured Notes					
U.S. Dollars (2007 and 2006 – US$400)	2010 to 2035	**399**	**5.4%**	466	5.3%
TC PIPELINES, LP					
Unsecured Loan					
U.S. dollars (2007 – US$507; 2006 – US$397)	2011	**499**	**6.2%**	463	5.4%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP[7]					
Senior Unsecured Notes					
U.S. dollars (2007– US$440)	2011 to 2030	**434**	**7.8%**		
TUSCARORA GAS TRANSMISSION COMPANY					
Senior Unsecured Notes					
U.S. dollars (2007 – US$69; 2006 – US$74)	2010 to 2012	**67**	**7.4%**	86	7.2%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Secured Notes					
U.S. dollars (2007 – US$211; 2006 – US$226)	2018	**205**	**6.1%**	263	5.9%
OTHER					
Senior Notes					
U.S. dollars (2007 – US$17; 2006 – US$24)	2011	**17**	**7.3%**	28	7.3%
		12,933		11,503	
Less: Current Portion of Long-Term Debt		**556**		616	
		12,377		10,887	

(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.

(2) Weighted average and effective interest rates are stated as at the respective outstanding dates. The effective weighted average interest rate resulting from swap agreements was six per cent in 2007 on TCPL's U.S. dollar Medium-Term Notes (2006 – 5.8 per cent).

(3) Interest rates are the weighted average interest rates.

(4) Includes fair value adjustments for swap agreements on US$50 million of debt at December 31, 2007.

(5) Includes fair value adjustments for swap agreements on $150 million of debt at December 31, 2007.

(6) Includes fair value adjustments for swap agreements on US$150 million of debt at December 31, 2007.

(7) TransCanada increased its effective ownership in Great Lakes to 68.5 per cent from 50.0 per cent on February 22, 2007. The Company commenced consolidation of Great Lakes on a prospective basis effective February 22, 2007.

Principal Repayments

Principal repayments on the long-term debt of the Company are approximately as follow: 2008 – $556 million; 2009 – $1,002 million; 2010 – $617 million; 2011 – $805 million; and 2012 – $1,246 million.

Debt Shelf Programs

In March 2007, the Company filed debt shelf prospectuses in Canada and the U.S. qualifying for issuance $1.5 billion of Medium-Term Notes and US$1.5 billion of debt securities, respectively. At December 31, 2007, the Company had issued no Medium-Term Notes under the Canadian prospectus. In September 2007, the Company replaced the March 2007 U.S. debt shelf prospectus with a US$2.5-billion U.S. debt shelf prospectus. US$1.5 billion remains available under the U.S. debt shelf at December 31, 2007.

TransCanada PipeLines Limited

In October 2007, TransCanada PipeLines Limited (TCPL) issued US$1.0 billion of Senior Unsecured Notes under the U.S. debt shelf prospectus filed in September 2007. These notes mature on October 15, 2037 and bear interest at a rate of 6.20 per cent. The effective interest rate at issuance was 6.30 per cent.

NOVA Gas Transmission Ltd.

Debentures issued by NOVA Gas Transmission Ltd. (NGTL) amount to $225 million and 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 at December 31, 2007.

On January 31, 2008, NGTL retired $105 million of 6.0 per cent Medium-Term Notes.

TransCanada PipeLine USA Ltd.

In February 2007, TransCanada PipeLine USA Ltd. established a US$1.0 billion committed, unsecured credit facility, consisting of a US$700-million five-year term loan and a US$300-million five-year, extendible revolving facility. A floating interest rate based on the three-month London Interbank Offered Rate (LIBOR) plus 22.5 basis points is charged on the balance outstanding and a facility fee of 7.5 basis points is charged on the entire facility. US$1.0 billion from this facility and an additional US$100 million from an existing demand line were used to partially finance the acquisitions of ANR and additional interest in Great Lakes and the Company's additional investment in PipeLines LP. There was an outstanding balance of US$860 million on the credit facility and nil on the demand line at December 31, 2007.

ANR Pipeline Company – Voluntary Withdrawal of Listing

In March 2007, ANR Pipeline Company (ANR Pipeline) voluntarily withdrew, from the New York Stock Exchange, the 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, which became effective April 12, 2007, ANR Pipeline deregistered these securities with the U.S. Securities and Exchange Commission.

TC PipeLines, LP

In February 2007, PipeLines LP increased the size of its syndicated revolving credit and term loan facility in connection with its acquisition of a 46.4 per cent interest in Great Lakes. 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 senior term loan amount terminated upon closing of the Great Lakes acquisition. An additional US$18 million of the senior term loan was terminated due to a principal payment made in November 2007. A floating interest rate based on the three-month LIBOR plus 55 basis points is charged on the senior term loan and a floating interest rate based on the one-month LIBOR plus 35 basis points is charged on the senior revolving credit facility. A facility fee of 10 basis points is charged on the US$250-million senior revolving credit facility.

Sensitivity

A one per cent change in interest rates would have the following effects assuming all other variables were to remain constant:

(millions of dollars)	Increase	Decrease
Effect on fair value of fixed interest rate debt	(1,023)	1,185
Effect on interest expense of variable interest rate debt	7	(7)

Financial Charges

Year ended December 31 (millions of dollars)	**2007**	2006	2005
Interest on long-term debt	**948**	846	849
Interest on junior subordinated notes	**43**		
Interest on short-term debt	**48**	23	23
Capitalized interest	**(68)**	(60)	(24)
Amortization and other financial charges[1]	**(28)**	16	(12)
	943	825	836

[1] Amortization and other financial charges in 2007 includes amortization of transaction costs and debt discounts calculated using the effective interest method.

The Company made interest payments of $966 million in 2007 (2006 – $771 million; 2005 – $838 million).

NOTE 10 LONG-TERM DEBT OF JOINT VENTURES

		2007		2006	
Outstanding loan amounts (millions of dollars)	Maturity Dates	**Outstanding December 31[1]**	**Interest Rate[2][3]**	Outstanding December 31[1]	Interest Rate[4]
NORTHERN BORDER PIPELINE COMPANY					
Senior Unsecured Notes (2007 – US$232; 2006 – US$316)	2009 to 2021	**229**	**7.7%**	368	6.9%
Bank Facility (2007 – US$83)	2012	**82**	**5.3%**		
IROQUOIS GAS TRANSMISSION SYSTEM, L.P.					
Senior Unsecured Notes (2007 and 2006 – US$165)	2010 to 2027	**162**	**7.4%**	192	7.5%
Bank Loan (2007 – US$7; 2006 – US$15)	2008	**7**	**7.4%**	17	6.2%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP[5]					
Senior Unsecured Notes (2006 – US$225)		**–**		262	7.8%
BRUCE POWER L.P. AND BRUCE POWER A L.P.					
Capital Lease Obligations	2018	**243**	**7.5%**	250	7.5%
TRANS QUÉBEC & MARITIMES PIPELINE INC.					
Bonds	2009 to 2010	**137**	**6.0%**	138	6.0%
Term Loan	2011	**28**	**4.6%**	32	4.4%
Other	2008 to 2013	**15**	**4.5%**	19	3.8%
		903		1,278	
Less: Current Portion of Long-Term Debt of Joint Ventures		**30**		142	
		873		1,136	

(1) Amounts outstanding represent TransCanada's proportionate share.

(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.

(3) Weighted average and effective interest rates are stated as at the respective outstanding dates. At December 31, 2007, the effective interest rate resulting from swap agreements were 7.5 per cent on the Iroquois bank loan (2006 – weighted average rate of 6.9 per cent).

(4) Weighted average interest rates are stated at the respective outstanding dates.

(5) TransCanada increased its effective ownership in Great Lakes to 68.5 per cent from 50.0 per cent on February 22, 2007. The Company commenced consolidation of Great Lakes, on a prospective basis, effective February 22, 2007.

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 by each joint venture is limited to the rights and assets of that joint venture and does not extend to the rights and assets of TransCanada, except to the extent of TransCanada's investment. Other joint venture debt includes a demand loan secured by a first interest in all personal property, a floating charge over all real property and a demand collateral leasehold mortgage in the amount of $20 million creating a first fixed and specific charge over the joint venture's leasehold interest in all land and premises. TQM's Bonds are secured by a first interest in all TQM 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 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 resulting from maturities and sinking fund obligations of the non-recourse joint venture debt is approximately as follows: 2008 – $21 million; 2009 – $161 million; 2010 – $185 million; 2011 – $36 million; and 2012 – $95 million.

The Company's proportionate share of principal payments resulting from the capital lease obligations of Bruce Power is approximately as follows: 2008 – $9 million; 2009 – $11 million; 2010 – $13 million; 2011 – $15 million; and 2012 – $18 million.

In April 2007, Northern Border established a US$250-million five-year bank facility. A portion of the bank facility was drawn to refinance US$150 million of the Senior Unsecured Notes that matured on May 1, 2007, with the balance available to fund Northern Border's ongoing operations.

Sensitivity

A one per cent change in interest rates would have the following effects assuming all other variables were to remain constant:

(millions of dollars)	Increase	Decrease
Effect on fair value of fixed interest rate debt	(13)	15
Effect on interest expense of variable interest rate debt	1	(1)

Financial Charges of Joint Ventures

Year ended December 31 (millions of dollars)	**2007**	2006	2005
Interest on long-term debt	**50**	67	60
Interest on capital lease obligations	**18**	19	3
Short-term interest and other financial charges	**4**	3	1
Deferrals and amortization	**3**	3	2
	75	92	66

The Company's proportionate share of the interest payments of joint ventures was $45 million in 2007 (2006 – $73 million; 2005 – $62 million).

The Company's proportionate share of interest payments from the capital lease obligations of Bruce Power was $26 million in 2007 (2006 – $20 million; 2005 – $3 million).

NOTE 11 JUNIOR SUBORDINATED NOTES

		2007	
Outstanding loan amount (millions of dollars)	Maturity Dates	**Outstanding December 31**	**Effective Interest Rate**
TRANSCANADA PIPELINES LIMITED			
U.S. dollars (2007 – US$1,000)	2017	**975**	**6.5%**

In April 2007, TCPL issued US$1.0 billion of Junior Subordinated Notes, maturing in 2067 and bearing interest of 6.35 per cent per year until May 15, 2017, when interest will convert to a floating rate, reset quarterly to the three-month LIBOR 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. The Company would be prohibited from paying dividends during any 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 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 upon the occurrence of certain events and at the Company's option, in whole or in part, 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 formula in accordance with the terms of the Junior Subordinated Notes. The Junior Subordinated Notes were issued under the U.S. shelf prospectus filed in March 2007.

Sensitivity

A one per cent change in interest rates would have the following effects assuming all other variables were to remain constant:

(millions of dollars)	Increase	Decrease
Effect on fair value of Junior Subordinated Notes	(61)	66

NOTE 12 DEFERRED AMOUNTS

December 31 (millions of dollars)	**2007**	2006
Regulatory liabilities	**525**	386
Fair value of derivative contracts	**205**	254
Employee benefit plans	**196**	195
Asset retirement obligations	**88**	45
Hedging deferrals(1)	**–**	84
Other	**93**	65
	1,107	1,029

(1) Changes in GAAP required the Company to record the effective portion and changes in fair value of cash flow and fair value hedges in Other Comprehensive Income and Net Income, respectively, effective January 1, 2007. Prior to this date, the fair value of certain hedges was deferred and recognized in income when the financial instrument had settled.

NOTE 13 REGULATED BUSINESSES

Regulatory assets and liabilities represent future revenues that are expected to be recovered from or refunded to customers in future periods. They stem from the rate-setting process associated with certain costs and revenues, incurred in the current period or in prior periods and the under- or over-collection of revenues in the current or prior periods.

Canadian Regulated Operations

Canadian natural gas transmission services are supplied under 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 wholly owned and partially owned 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, equal the revenues for the upcoming year. To the extent that actual costs are more or less than the forecasted costs, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in revenues 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, Foothills and TQM pipelines are regulated by the NEB under the *National Energy Board Act*. At December 31, 2007, the Alberta System was regulated by the EUB primarily under the provisions of the *Gas Utilities Act (Alberta)* and the *Pipeline Act (Alberta)*. The EUB was reorganized into the AUC and the Energy Resource Conservation Board effective January 1, 2008. The AUC regulates the Alberta System's construction and operation of facilities, and the terms and conditions of services, including rates. The NEB regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for the Company's other Canadian regulated transmission systems.

Canadian Mainline
In February 2007, TransCanada reached a five-year tolls settlement with interested stakeholders for 2007 to 2011 on the Canadian Mainline. In May 2007, the NEB approved the application as filed, including TransCanada's request that interim tolls for 2007 be made final. The terms of the settlement are effective January 1, 2007, to December 31, 2011.

As part of the settlement, TransCanada and its stakeholders agreed that the cost of capital will reflect a rate of return on common equity (ROE) as determined by the NEB's ROE formula, on a deemed common equity ratio of 40 per cent, an increase from 36 per cent. The allowed ROE in 2007 for Canadian Mainline was 8.46 per cent. The remaining capital structure consists of short- and long-term debt following the agreed-upon redemption of the US$460-million Preferred Securities.

The settlement also established the Canadian Mainline's fixed operating, maintenance and administration (OM&A) costs for each year of the five years. Any variance between actual OM&A costs and those agreed to in the settlement will accrue 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 will be treated on a flow-through basis. The settlement also allows for performance-based incentive arrangements that will provide mutual benefits to both TransCanada and its customers.

Alberta System
The Alberta System operated under the 2005-2007 Revenue Requirement Settlement. This settlement, approved by the EUB in June 2005, encompassed all elements of the Alberta System's revenue requirement for 2005, 2006 and 2007 and established methodologies for calculating the revenue requirement for all three years, based on the recovery of all cost components and the use of deferral accounts.

OM&A and certain other costs, including foreign exchange on interest payments, uninsured losses and amortization of severance costs, were fixed for each of the three years and any difference between actual and forecast fixed costs will be included in the determination of net income in the year they are incurred. Costs other than those that are fixed are forecast at the beginning of each year and included in calculating the revenue requirement. Any variance between forecasted and actual costs is included in a deferral account and adjusted in the following year's revenue requirement. The settlement also set the ROE using the formula for determining the annual generic ROE established in the EUB's General Cost of Capital Decision 2004-052 on a deemed common equity of 35 per cent for all three years. The allowed ROE in 2007 was 8.51 per cent.

Other Canadian Pipelines
In February 2007, the NEB approved TransCanada's application to integrate the BC System and Foothills and charge tolls based on the integrated structure. The two systems were integrated effective April 1, 2007, resulting in a transfer of BC System regulatory assets and liabilities to Foothills. The ROE for Foothills, which is based on the NEB-allowed ROE formula established in the RH-2-94 Multi-Pipeline Cost of Capital proceeding, was 8.46 per cent in 2007 on a deemed equity component of 36 per cent.

The NEB approves pipeline tolls on an annual cost of service basis for Foothills and TQM, similar to the basis it uses to approve tolls on the Canadian Mainline. The NEB allows each pipeline to charge a schedule of tolls based on the estimated cost of service. This schedule of tolls is used for the current year until a new toll filing is made for the following year. Differences between the estimated cost of service and the actual cost of service are calculated and reflected in the subsequent year's tolls.

TQM filed an application with the NEB in November 2007 for approval of a three-year partial negotiated settlement for the years 2007 to 2009. The partial settlement represents agreement on all cost of service matters for the three-year period, with the exception of cost of capital and associated income taxes. In December 2007, TQM filed a cost of capital application with the NEB for the years 2007 and 2008. The application requests approval of an 11 per cent return on deemed common equity of 40 per cent. TQM currently is subject to an NEB ROE formula on deemed common equity of 30 per cent. TQM tolls remain in effect on an interim basis pending a decision on the application. Any adjustments to the interim tolls will be recorded in accordance with the decision.

U.S. Regulated Operations

TransCanada's wholly owned and partially owned U.S. 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 E*nergy Project 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 that are regulated by the FERC also operate under approved tariff rates. ANR Pipeline's rates were established pursuant to a settlement approved by a FERC order issued in February 1998 and became effective in November 1997. 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 April 1990 and became effective in 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 case for new rates.

GTN

GTN is regulated by the FERC. Both of GTN's systems, the GTN System and North Baja, operate in accordance with FERC-approved tariffs that establish maximum and minimum rates for various services. The pipelines are permitted to discount or negotiate these rates on a non-discriminatory basis. The GTN System filed a general rate case in June 2006 under the *Natural Gas Act of 1938*. The GTN System filed a Stipulation and Agreement with the FERC on November 1, 2007, that comprised an uncontested settlement of all aspects of its 2006 rate case. The FERC approved the settlement on January 7, 2008, and GTN's financial results in 2007 reflect the terms of the settlement. In 2008, the GTN System will refund to customers amounts collected above the settlement rates for the period from January 1, 2007 through October 31, 2007. Under the settlement, a five-year moratorium period was set in which the GTN System and the settling parties are prohibited from taking certain actions under the *Natural Gas Act of 1938*, including any filings. The GTN System is also required to file a rate case within seven years. Rates for capacity on North Baja were established in 2002 in the FERC's initial order certificating construction and operations of North Baja.

Great Lakes

Great Lakes' rates and tariffs are regulated by the FERC. In 2000, Great Lakes negotiated an overall rate settlement with its customers that established the current rates. The settlement expired October 31, 2005, with no requirement to file for new rates at any time in the future, nor is Great Lakes prohibited from filing such a rate case.

Portland

In 2003, Portland received final approval from the FERC of its general rate case under the *Natural Gas Act of 1938*. Portland is required to file a general rate case under Section 4 of the *Natural Gas Act of 1938*, with a proposed effective date of April 1, 2008.

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. Beginning January 1, 2007, overall rates were reduced by approximately five per cent from the rates in effect prior to the filing. The settlement 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 that Northern Border file a general rate case within six years. Northern Border was 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)	**2007**	2006	Remaining Recovery/ Settlement Period
			(years)
Regulatory Assets			
Operating and debt-service regulatory assets[1]	**85**		1
Unrealized losses on derivatives – Canadian Mainline[2]	**63**	44	1 - 3
Unrealized losses on derivatives – Foothills[2]	**33**	33	6
Unrealized losses on derivatives – Alberta System[2]	**10**	7	1 - 5
Foreign exchange on long-term debt principal – Alberta System[3]	**34**	33	22
Deferred income tax on carrying costs capitalized during construction of utility plant – ANR[4]	**20**		n/a
Unamortized issue costs on Preferred Securities – Canadian Mainline[5]	**19**		19
Phase II preliminary expenditures – Foothills[6]	**18**	20	8
Transitional other benefit obligations[7]	**16**	18	9
Unamortized post-retirement benefits – ANR[8]	**13**		4 - 6
Other	**25**	23	n/a
Total Regulatory Assets (Other Assets)	**336**	178	
Regulatory Liabilities			
Operating and debt-service regulatory liabilities[1]	**3**	70	1
Foreign exchange on long-term debt – Alberta System[9]	**168**	60	5 - 22
Foreign exchange on long-term debt – Canadian Mainline[9]	**61**	195	1 - 3
Foreign exchange on long-term debt – Foothills[9]	**37**	19	6
Foreign exchange gain on redemption of Preferred Securities, net of income tax of $15 million – Canadian Mainline[5]	**150**		4
Post-retirement benefits other than pension – ANR[10]	**38**		n/a
Fuel tracker – ANR[11]	**29**		n/a
Negative salvage – ANR[12]	**17**		n/a
Post-retirement benefits other than pension – GTN System[13]	**–**	19	4
Other	**22**	23	n/a
Total Regulatory Liabilities (Deferred Amounts)	**525**	386	

(1) Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances approved by the regulatory authority for inclusion in the determination of tolls for the immediate following calendar year. In the absence of rate-regulated accounting, GAAP would have required the inclusion of variances resulting in a regulatory asset in the operating results of the year in which the variances were incurred. There is no difference between rate-regulated and GAAP accounting treatments if the variances yield a regulatory liability. Pre-tax operating results would have been $85 million lower in 2007 (2006 – no change) in the absence of rate-regulated accounting.

(2) Unrealized losses on derivatives represent the net position of fair value gains and losses on cross-currency and interest-rate swaps, and forward currency contracts which act as economic hedges. The cross-currency swaps pertain to foreign debt instruments associated with the Canadian Mainline, Foothills and Alberta System. The Canadian Mainline interest-rate swaps were entered into as a result of the Mainline Interest Rate Management Program approved by the NEB as a component of the 1996 - 1999 Incentive Cost Recovery and Revenue Settlement. Interest savings or losses are determined when the interest swaps are settled. In the absence of rate-regulated accounting, GAAP would have required the inclusion of these fair value losses in the operating results of the Canadian Mainline, as they were not documented as hedges for accounting purposes. In the absence of rate-regulated accounting, pre-tax operating results of the Canadian Mainline would have been $19 million lower in 2007 (2006 – $1 million lower). The regulatory asset with respect to Foothills represents the unrealized losses for the ineffective period of the derivative from inception to December 31, 2005. In the absence of rate-regulated accounting, pre-tax operating results of Foothills would have been the same in 2007 and 2006. The regulatory asset related to the Alberta System represents cross-currency swaps on foreign debt instruments and forward foreign currency contracts related to hedging foreign exchange risk inherent in contractual obligations to purchase materials for construction projects. In the absence of rate-regulated accounting, pre-tax operating results of the Alberta System would have been $3 million lower in 2007 (2006 – no change).

(3) The foreign exchange on long-term debt principal account in the Alberta System, as approved by the EUB, is designed to facilitate the recovery or refund of foreign exchange gains and losses over the life of the foreign currency debt issues. The estimated gain or loss on

foreign currency debt is 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.

(4) Rate-regulated accounting allows the capitalization of both an equity and an interest component for the carrying costs of funds used during the construction of utility assets. The capitalized Allowance for Funds Used During Construction (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 deferred tax provision is recorded with an offset to a corresponding regulatory asset.

(5) 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, there was a realized foreign exchange gain that will flow through, net of income tax, to Canadian Mainline's customers over the five years of the settlement approved by the NEB in May 2007. In addition, the issue costs on the Preferred Securities will be amortized over 20 years beginning January 1, 2007. In the absence of rate-regulated accounting, GAAP would have required the foreign exchange gain and the unamortized issue costs to be included in the operating results of the Canadian Mainline in the year the securities were redeemed. This would have increased/(decreased) pre-tax operating results by $165 million and $(19) million arising from the foreign exchange gain and issue costs, respectively, in 2007.

(6) 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 1, 2002 to December 31, 2015. In the absence of rate-regulated accounting, GAAP would have required these costs to be expensed in the year incurred, increasing pre-tax operating results by $2 million in 2007 (2006 – $3 million higher).

(7) The regulatory asset with respect to the annual transitional other benefit obligations is being amortized over 17 years, from January 1, 2000 to December 31, 2016, at which time the full transitional obligation will have been recovered through tolls. In the absence of rate-regulated accounting, pre-tax operating results would have been $2 million higher in 2007 (2006 – $2 million higher).

(8) 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 at a rate of $3 million per year through 2011. In the absence of rate-regulated accounting, pre-tax operating results would have been $3 million higher in 2007.

(9) Foreign exchange on long-term debt of the Canadian Mainline, the Alberta System and Foothills represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historic 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 either 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.

(10) An amount is recovered in ANR's rates for post-employment and post-retirement benefits. This regulatory liability represents the difference between the amount collected in rates and the amount of post-employment and post-retirement benefit expense.

(11) ANR's tariff stipulates a fuel tracker mechanism to track over- or under-collections of fuel used and lost and gas 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.

(12) ANR collects in its current rates an allowance for negative salvage related to its offshore transmission and gathering facilities. The allowance for negative salvage is collected as a component of depreciation expense and recorded to a negative salvage account within the reserve for accumulated depreciation. Costs associated with the abandonment of offshore transmission and with gathering facilities are recorded against the negative salvage reserve.

(13) An amount was recovered for PBOP in the GTN System's rates under a 1996 rate case settlement. This regulatory liability represents the difference between the amount collected in rates and the amount of PBOP expense determined under GAAP. Under the terms of the 2007 settlement, the GTN System's PBOP regulatory liability is deemed to be nil and, as such, has been transferred to other deferred amounts. The December 31, 2006 balance is being amortized over five years.

As prescribed by regulators, the taxes payable method of accounting for income taxes is used for toll-making purposes on Canadian regulated natural gas transmission operations. As permitted by GAAP, this method is also used for accounting purposes, since there is a reasonable expectation that future income taxes payable will be included in future costs of service and recorded in revenues at that time. Consequently, future income tax liabilities have not been recognized, as it is expected that when these amounts become payable, they will be recovered through future rates. In the absence of rate-regulated accounting, GAAP would have required the recognition of future income tax liabilities. If the liability method of accounting had been used, additional future income tax liabilities of $1,138 million would have been recorded at December 31, 2007 (2006 – $1,355 million) and would have been recoverable from future revenues. In 2007, reductions in enacted Canadian federal and provincial corporate future income tax rates resulted in a decrease of $123 million to this unrecorded future income tax liability. The liability method of accounting is used for both accounting and toll-making purposes for the U.S. natural gas transmission operations.

Under this method, future income tax assets and liabilities are recognized based on the differences between financial statement carrying amounts and the tax basis of the assets and liabilities. This method is also used for toll-making purposes for the U.S. natural gas transmission operations. As a result, current year's revenues include a tax provision that is calculated based on the liability method of accounting and there is no recognition of a related regulatory asset or liability.

NOTE 14 PREFERRED SECURITIES

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

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)	**2007**	2006
Non-controlling interest in PipeLines LP	**539**	287
Preferred shares of subsidiary	**389**	389
Other	**71**	79
	999	755

The Company's non-controlling interests included in the consolidated income statement are as follows.

Year ended December 31 (millions of dollars)	**2007**	2006	2005
Non-controlling interest in PipeLines LP	**65**	43	52
Preferred share dividends of subsidiary	**22**	22	22
Other	**10**	13	10
	97	78	84

The non-controlling interest in PipeLines LP as at December 31, 2007, represented the 67.9 per cent interest not owned by TransCanada (2006 – 86.6 per cent). Other non-controlling interests as at December 31, 2007, included the 38.3-per-cent (2006 – 38.3 per cent) non-controlling interest in Portland held by an unrelated partner.

TransCanada received revenues of $2 million from PipeLines LP in 2007 (2006 – $1 million; 2005 – $1 million) and $7 million from Portland in 2007 (2006 – $6 million; 2005 – $6 million) for services it provided.

Preferred Shares of Subsidiary

December 31	Number of Shares	Dividend Rate Per Share	Redemption Price Per Share	**2007**	2006
	(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 series is unlimited. All of the cumulative first preferred shares of TCPL are without par value.

The issuer may redeem at $50 per share the Series U shares on or after October 15, 2013, and the Series Y shares on or after March 5, 2014.

NOTE 16 COMMON SHARES

	Number of Shares	Amount
	(thousands)	(millions of dollars)
Outstanding at January 1, 2005	484,914	4,711
Exercise of options	2,322	44
Outstanding at December 31, 2005	487,236	4,755
Exercise of options	1,739	39
Outstanding at December 31, 2006	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**

(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 January 2007, TransCanada filed a short form shelf prospectus with securities regulators in Canada and the U.S. to allow for the offering of up to $3.0 billion of common shares, preferred shares and/or subscription receipts in Canada and the U.S. until February 2009. In 2007, the Company issued 45.4 million common shares at a price of $38.00 each, generating gross proceeds of approximately $1.725 billion. The proceeds were used towards financing the acquisitions of ANR and an increased ownership interest in Great Lakes.

Net Income per Share

Basic and diluted earnings per share are calculated based on the weighted average number of common shares outstanding during the year of 529.9 million and 532.5 million (2006 – 488.0 million and 490.6 million; 2005 – 486.2 million and 489.1 million), 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, 2005	9,965	$20.90	7,239
Granted	1,075	$30.21	
Exercised	(2,322)	$18.57	
Cancelled or expired	(4)	$25.34	
Outstanding at December 31, 2005	8,714	$22.67	6,300
Granted	1,841	$34.48	
Exercised	(1,739)	$21.44	
Cancelled or expired	(17)	$30.98	
Outstanding at December 31, 2006	8,799	$25.37	5,888
Granted	**1,083**	**$38.10**	
Exercised	**(1,253)**	**$22.77**	
Cancelled or expired	**(20)**	**$35.08**	
Outstanding at December 31, 2007	**8,609**	**$27.32**	**6,118**

Stock options outstanding at December 31, 2007, were as follow:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
	(thousands)	(years)		(thousands)	
$10.03 to $20.27	1,013	2.9	$15.58	1,013	$15.58
$20.58 to $21.86	1,524	3.8	$21.15	1,524	$21.15
$22.33 to $24.49	1,134	2.1	$22.65	1,134	$22.65
$24.61 to $26.85	1,103	3.1	$26.81	1,103	$26.81
$30.09 to $33.08	1,585	4.8	$31.28	860	$30.81
$35.23 to $36.67	1,180	5.2	$35.25	484	$35.27
$38.10 to $38.14	1,070	6.2	$38.10	–	–
	8,609	4.0	$27.32	6,118	$24.00

An additional five million common shares were reserved for future issuance under TransCanada's Stock Option Plan at December 31, 2007. In 2007, TransCanada issued 976,217 and 107,199 options to purchase common shares at a price of $38.10 and $38.14, respectively, under the Company's Stock Option Plan and the weighted average fair value of each option was determined to be $4.22. The Company used the Black-Scholes model for determining the fair value of options granted applying the following weighted average assumptions for 2007: four years of expected life (2006 and 2005 – four years); 4.1 per cent interest rate (2006 – 4.1 per cent; 2005 – 4.0 per cent); 15 per cent volatility (2006 – 14 per cent; 2005 – 15 per cent); and 3.6 per cent dividend yield (2006 – 3.7 per cent; 2005 – 3.3 per cent). The amount expensed for stock options, with a corresponding increase in contributed surplus, was $4 million in 2007 (2006 – $3 million; 2005 – $3 million).

Shareholder Rights Plan

The Company'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.

Dividend Reinvestment and Share Purchase Plan

In 2007, TransCanada's Board of Directors authorized the issuance of common shares from treasury at a discount of two per cent to participants in the Company's Dividend Reinvestment and Share Purchase Plan (DRP). Eligible shareholders may reinvest their dividends and make optional cash payments to obtain additional TransCanada common shares under the DRP. Commencing with the dividend payable in April 2007, the DRP shares are provided to the participants at a two per cent discount to the average market price in the five days before dividend payment. Previously, 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 accordance with the DRP, dividends of $157 million were paid in 2007 by the issuance from treasury of 4.1 million common shares.

NOTE 17 RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TransCanada has exposure to market, counterparty credit and liquidity risk. The risk management function assists in managing these risks. TransCanada's primary risk management objective is to protect earnings and 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 personnel. TransCanada's Audit Committee oversees how management monitors compliance with risk management policies and procedures, and 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 commodities, issues short- 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 policy to manage exposures to market risk that result from these activities.

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, for 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.
- Heat rate contracts – contracts for the purchase or sale of power that are priced based on a natural gas index.

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 power and natural gas. A number of strategies are used to mitigate these exposures, including the following:

- The Company enters into offsetting or back-to-back physical positions and derivative financial instruments to manage market risk exposures created by certain fixed and variable pricing arrangements at different pricing indices and delivery points.
- Subject to the Company's overall risk management policies, the Company commits a significant portion of its power supply to medium- or long-term sales contracts, while reserving an amount of unsold supply to maintain operational flexibility in the overall management of its asset portfolio.
- The Company purchases a portion of the natural gas required for its gas-fired cogeneration plants or enters into heat-rate 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 requirements is purchased with forward contracts or fulfilled through power generation, thereby reducing the Company's exposure to fluctuating commodity prices.

The Company assesses its commodity contracts and derivative instruments used to manage energy commodity risk to determine the appropriate accounting treatment. Contracts, with the exception of leases, have been assessed to determine whether they meet the definition of a derivative. Certain commodity purchase and sale contracts are derivatives but are not within the scope of 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 normal purchases and normal sales exemption. 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 hedging storage capacity with a portfolio of third-party storage capacity leases and proprietary natural gas purchases and sales. By matching purchase and sale volumes, TransCanada locks in a margin on a back-to-back basis and thereby effectively eliminates its exposure to natural gas market price fluctuations.

Natural Gas Inventory Price Risk

Effective April 1, 2007, TransCanada began valuing its proprietary natural gas inventory held in storage at fair value, as measured by the one-month forward price for natural gas. At December 31, 2007, $190 million of proprietary natural gas inventory was included in Inventories. The amount recorded in 2007 in Revenues for the net change in the fair value of proprietary natural gas held in inventory was insignificant. A gain of $10 million was recorded in 2007 in Revenues for the net change in fair value of the forward proprietary natural gas purchase and sales contracts.

Foreign Exchange and Interest Rate Risk

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

A portion of TransCanada's earnings from its Pipelines and Energy operations outside of Canada is generated primarily in U.S. dollars and is subject to currency fluctuations. The performance of the Canadian dollar relative to the U.S. dollar could positively or negatively affect TransCanada's earnings. This foreign exchange impact is offset by exposures in certain of TransCanada's businesses and by the Company's hedging activities. Due to its growing operations in the U.S., including the acquisitions of ANR and increased ownership in Great Lakes and PipeLines LP, TransCanada expects to have a greater exposure to U.S. dollar fluctuations than in prior years.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to its U.S. dollar-denominated debt and other transactions, as well as to manage the interest rate exposures of the Canadian Mainline, Alberta System and Foothills. 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.

The Company has fixed-rate long-term debt, which subjects it to interest rate price risk, and has floating interest rate debt, which subjects it to interest rate cash flow risk. The Company uses a combination of forwards, interest rate swaps and options to manage its exposure to these risks.

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, forward contracts, cross-currency interest rate swaps and options. The Company had designated U.S. dollar-denominated debt with a carrying value of $4.7 billion (US$4.7 billion) and a fair value of $4.8 billion (US$4.8 billion) as a net investment hedge at December 31, 2007. The forwards, swaps and options are recorded at their fair value and are included in Other Assets.

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

Asset/(Liability) *December 31 (millions of dollars)*	**2007** Fair Value	**2007** Notional or Principal Amount	2006 Fair Value	2006 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2009 to 2014)	**77**	**U.S. 350**	58	U.S. 400
U.S. dollar options (maturing 2008)	**3**	**U.S. 600**	(6)	U.S. 500
U.S. dollar forward foreign exchange contracts (maturing 2008)	**(4)**	**U.S. 150**	(7)	U.S. 390
	76	**U.S. 1,100**	45	U.S. 1,290

VaR Analysis
TransCanada uses a Value-at-Risk methodology (VaR) to estimate the potential impact resulting from its exposure to market risk. 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 the 95 per cent probability that the daily change resulting from normal market fluctuations in its liquid positions will not exceed the reported VaR. VaR methodology is a statistically-defined, probability-based approach that takes into consideration market volatilities as well as risk diversification by recognizing offsetting positions and correlations between products and markets. Risks are measured across all products and markets, and risk measures can be 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 and limits TransCanada's ability to manage these risks. The Company'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 less than $10 million at December 31, 2007.

Counterparty Credit Risk
Counterparty credit risk represents the financial loss that the Company would experience if a counterparty to a financial instrument, in which the Company has an amount owing from the counterparty, failed to meet its obligations in accordance with the terms and conditions of its contracts with the Company.

Counterparty credit risk is mitigated 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, utilizing 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.

TransCanada's maximum counterparty credit exposure at the balance sheet date consists primarily of the carrying amount of non-derivative financial assets as well as the fair value of derivative financial assets.

The Company has contracts for the sale of non-financial items. Many of these contracts do not meet the definition of a financial instrument since the underlying volumes are physically delivered during the Company's normal course of business. Exposure to counterparty credit risk on these non-financial contracts results from the potential of a counterparty defaulting on invoiced amounts owing to TransCanada. These invoiced amounts are included in the Accounts Receivable and Other Assets amounts disclosed in the Non-Derivative Financial Instruments Summary table presented later in this Note. Some of these non-financial contracts do meet the definition of a derivative and are recorded at fair value.

The carrying amounts and fair values of financial assets and non-financial derivatives are disclosed in the Non-Derivative Financial Instruments Summary and the Derivative Financial Instruments Summary tables presented later in this Note.

The Company does not have any significant concentrations of counterparty credit risk and the majority of the counterparty credit exposure is with counterparties who are investment grade.

The Company has reached agreements for allowed unsecured claims with certain subsidiaries of Calpine Corporation (Calpine), former shippers on TransCanada's pipeline systems that have filed for bankruptcy protection, as discussed in Note 25.

Liquidity Risk

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

Management typically forecasts cash flows for a period of 12 months to identify financing requirements. These requirements are then addressed through a combination of committed and demand credit facilities and access to capital markets, as discussed in the Capital Management section in this Note.

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, 2007:

Contractual Repayments of Financial Liabilities

		Payments Due by Period			
December 31, 2007 (millions of dollars)	Total	2008	2009 to 2010	2011 to 2012	2013 and Thereafter
Notes payable	421	421	–	–	–
Long-term debt and junior subordinated notes	13,908	556	1,619	2,051	9,682
Long-term debt of joint ventures	903	30	370	164	339
Total contractual repayments	15,232	1,007	1,989	2,215	10,021

Interest Payments on Financial Liabilities

		Payments Due by Period			
December 31, 2007 (millions of dollars)	Total	2008	2009 to 2010	2011 to 2012	2013 and Thereafter
Interest payments on long-term debt and junior subordinated notes	11,566	895	1,636	1,464	7,571
Interest payments on long-term debt of joint ventures	332	55	85	53	139
Total interest payments	11,898	950	1,721	1,517	7,710

Capital Management

The primary objective of capital management is to ensure TransCanada's strong credit rating is maintained to support its businesses and maximize shareholder value. This overall objective and policy for managing capital remained unchanged in 2007 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, Junior Subordinated Notes and Preferred Securities 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 at December 31, 2007 was as follows:

(millions of dollars)	
Notes payable	**407**
Long-term debt	**12,933**
Junior subordinated notes	**975**
Cash and cash equivalents	**(333)**
Net debt	**13,982**
Non-controlling interests	**999**
Shareholders' equity	**9,785**
Total equity	**10,784**
Total capital	**24,766**

Fair Values

The fair value of Cash and Cash Equivalents and Notes Payable approximates their carrying amounts due to the short time period 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 heat rate derivatives has been calculated using estimated forward prices for the relevant period.

Fair values of financial instruments are determined by reference to quoted bid or asking price, as appropriate, in active markets at period-end dates. In the absence of an active market, the Company determines fair value by using valuation techniques that refer to observable market data or estimated market prices. These include comparisons with similar instruments that have observable market prices, option pricing models and other valuation techniques commonly used by market participants. Fair values determined using valuation models require the use of assumptions about the amount and timing of estimated future cash flows and discount rates. In making these assumptions, the Company looks primarily to readily observable external market input factors such as interest rate yield curves, currency rates, and price and rate volatilities as applicable.

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, by discounting future payments of interest and principal at estimated interest rates that were made available to the Company at December 31, 2007. The fair value of Preferred Securities was determined using market prices for the same or similar issues.

Fair Value of Long-Term Debt and Other Long-Term Securities
The carrying and fair values of long-term debt and other long-term securities were as follow:

	2007		2006	
December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Long-Term Debt				
TransCanada PipeLines Limited[(1)]	**8,519**	**9,400**	8,549	9,738
NOVA Gas Transmission Ltd.	**1,508**	**1,877**	1,648	2,111
TransCanada PipeLine USA Ltd.	**850**	**850**	–	–
ANR Pipeline Company	**435**	**573**		
Gas Transmission Northwest Corporation	**399**	**383**	466	450
TC PipeLines, LP	**499**	**499**	463	463
Great Lakes Gas Transmission Limited Partnership	**434**	**519**	–	–
Tuscarora Gas Transmission Company	**67**	**81**	86	94
Portland Natural Gas Transmission System	**205**	**214**	263	265
Other	**17**	**24**	28	28
	12,933	**14,420**	11,503	13,149
Junior Subordinated Notes	**975**	**914**	–	–
	13,908	**15,334**	11,503	13,149
Long-Term Debt of Joint Ventures				
Northern Border Pipeline Company	**311**	**329**	368	363
Iroquois Gas Transmission System, L.P.	**169**	**180**	209	230
Great Lakes Gas Transmission Limited Partnership	**–**	**–**	262	258
Bruce Power L.P. and Bruce Power A L.P.	**243**	**243**	250	249
Trans Québec & Maritimes Pipeline Inc.	**165**	**169**	171	177
Other	**15**	**16**	18	18
	903	**937**	1,278	1,295
	14,811	**16,271**	12,781	14,444
Preferred Securities	**–**	**–**	536	532

(1) Carrying amount of Long-Term Debt increased $15 million for fair value adjustments of swap agreements on $150 million and US$200 million of debt.

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

December 31, 2007 (millions of dollars)	Carrying Amount	Fair Value
Financial Assets[(1)]		
Cash and cash equivalents	**504**	**504**
Accounts receivable and other assets[(2)(3)]	**1,231**	**1,231**
Available-for-sale assets[(2)]	**17**	**17**
	1,752	**1,752**
Financial Liabilities[(1)(3)]		
Notes payable	**421**	**421**
Accounts payable and deferred amounts[(4)]	**1,454**	**1,454**
Long-term debt and junior subordinated notes	**13,908**	**15,334**
Long-term debt of joint ventures	**903**	**937**
Other long-term liabilities of joint ventures[(4)]	**60**	**60**
	16,746	**18,206**

(1) Consolidated Net Income in 2007 included unrealized gains or losses of nil for the fair value adjustments to each of these financial instruments.

(2) The Consolidated Balance Sheet included financial assets of $1,018 million in Accounts Receivable and $230 million in Other Assets at December 31, 2007.

(3) Recorded at amortized cost, except for Long-Term Debt adjusted to fair value as noted in Note 9.

(4) The Consolidated Balance Sheet included financial liabilities of $1,436 million in Accounts Payable and $78 million in Deferred Amounts at December 31, 2007.

Derivative Financial Instruments Summary

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

December 31 *(all amounts in millions unless otherwise indicated)*	2007 Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading				
Fair Values(1)				
Assets	$55	$43	$11	$23
Liabilities	$(44)	$(19)	$(79)	$(18)
Notional Values				
Volumes(2)				
Purchases	3,774	47	–	–
Sales	4,469	64	–	–
Canadian dollars	–	–	–	615
U.S. dollars	–	–	U.S. 484	U.S. 550
Japanese yen (in billions)	–	–	JPY 9.7	–
Cross-currency	–	–	227/U.S. 157	–
Unrealized gains/(losses) in the period(3)	$16	$(10)	$8	$(5)
Realized (losses)/gains in the period(3)	$(8)	$47	$39	$5
Maturity dates	2008 - 2016	2008 - 2010	2008 - 2012	2008 - 2016
Derivative Financial Instruments in Hedging Relationships(4)(5)				
Fair Values(1)				
Assets	$135	$19	$ –	$2
Liabilities	$(104)	$(7)	$(62)	$(16)
Notional Values				
Volumes(2)				
Purchases	7,362	28	–	–
Sales	16,367	4	–	–
Canadian dollars	–	–	–	150
U.S. dollars	–	–	U.S. 113	U.S. 875
Cross-currency	–	–	136/U.S. 100	–
Realized (losses)/gains in the period(3)	$(29)	$18	$ –	$3
Maturity dates	2008 - 2013	2008 - 2010	2008 - 2013	2008 - 2013

(1) Fair value is equal to the carrying value of these derivatives.

(2) Volumes for power and natural gas derivatives are in gigawatt hours and billion cubic feet, respectively.

(3) All realized and unrealized gains and losses are included in Net Income. Realized gains are included in Net Income after the financial instrument has been settled.

(4) All hedging relationships are designated as cash flow hedges except for $2 million of interest-rate derivative financial instruments designated as fair value hedges.

(5) Net Income in 2007 included gains of $7 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. Net Income in 2007 included a loss of $4 million for the changes in fair value of an interest-rate cash flow hedge that was reclassified as a result of discontinuance of cash flow hedge accounting. The cash flow hedge accounting was discontinued when the anticipated transaction was not probable of occurring by the end of the originally specified time period.

Balance Sheet Presentation of Derivative Financial Instruments

The fair values of the derivative financial instruments in the Company's Balance Sheet were as follow:

December 31 (millions of dollars)	**2007**
Current	
Other current assets	**160**
Accounts payable	**(144)**
Long-term	
Other assets	**204**
Deferred amounts	**(205)**

Derivative Financial Instruments of Joint Ventures

Included in the Balance Sheet Presentation of Derivatives Financial Instruments table above are amounts related to power derivatives used by certain 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 $75 million at December 31, 2007. These contracts mature from 2008 to 2013. The Company's proportionate share of the notional sales volumes of power associated with this exposure was 7,300 gigawatt hours (GWh) at December 31, 2007. The Company's proportionate share of the notional purchased volumes of power associated with this exposure was 50 GWh at December 31, 2007.

NOTE 18 INCOME TAXES

Provision for Income Taxes

Year ended December 31 (millions of dollars)	**2007**	2006	2005
Current			
Canada	**367**	264	499
Foreign	**65**	37	51
	432	301	550
Future			
Canada	**12**	104	(46)
Foreign	**46**	71	106
	58	175	60
	490	476	610

Geographic Components of Income

Year ended December 31 (millions of dollars)	**2007**	2006	2005
Canada	**1,228**	1,161	1,316
Foreign	**582**	444	587
Income from continuing operations before income taxes and non-controlling interests	**1,810**	1,605	1,903

Reconciliation of Income Tax Expense

Year ended December 31 (millions of dollars)	**2007**	2006	2005
Income from continuing operations before income taxes and non-controlling interests	**1,810**	1,605	1,903
Federal and provincial statutory tax rate	**32.1%**	32.5%	33.6%
Expected income tax expense	**581**	522	639
Income tax differential related to regulated operations	**69**	72	71
(Lower)/higher effective foreign tax rates	**(39)**	–	2
Tax rate and legislated changes	**(72)**	(33)	–
Income from equity investments and non-controlling interests	**(34)**	(27)	(29)
Non-taxable portion of gains on sale of assets	**(3)**	–	(68)
Large corporations tax	**–**	–	15
Other[1]	**(12)**	(58)	(20)
Actual income tax expense	**490**	476	610

[1] Includes income tax benefits of $13 million recorded in 2007 on the resolution of certain income tax matters with taxation authorities and changes in estimates (2006 – $51 million).

Future Income Tax Assets and Liabilities

December 31 (millions of dollars)	**2007**	2006
Deferred amounts	**43**	65
Other post-employment benefits	**57**	45
Unrealized losses on derivatives	**22**	–
Other	**77**	53
	199	163
Less: valuation allowance	**13**	14
Future income tax assets, net of valuation allowance	**186**	149
Difference in accounting and tax bases of plant, equipment and PPAs	**1,073**	768
Investments in subsidiaries and partnerships	**61**	113
Pension benefits	**50**	59
Unrealized foreign exchange gains on long-term debt	**110**	39
Unrealized gains on derivatives	**27**	–
Other	**44**	46
Future income tax liabilities	**1,365**	1,025
Net future income tax liabilities	**1,179**	876

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 $72 million at December 31, 2007 (2006 – $72 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $442 million were made during the year ended December 31, 2007 (2006 – $494 million; 2005 – $531 million).

NOTE 19 NOTES PAYABLE

	2007		2006	
	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	**55**	**5.0%**	467	4.3%
U.S. dollars (2007 – US$370; 2006 – nil)	**366**	**5.5%**		
	421		467	

Notes Payable consists of commercial paper outstanding and drawings on bridge and line-of-credit facilities. Total unsecured revolving and demand credit facilities of $2.9 billion were available at December 31, 2007 to support the Company's commercial paper program and for general corporate purposes. These credit facilities include the following:

- in December 2007, the $1.5 billion committed five-year term syndicated credit facility was increased to $2.0 billion and extended to December 2012. The cost to maintain the credit facility was $2 million in 2007 (2006 – $2 million).
- at December 31, 2007, a US$300 million five-year, extendible revolving facility was available, which is part of the US$1.0 billion TransCanada PipeLine USA Ltd. credit facility discussed in Note 9.
- the Company also has in place $600 million of demand lines, which support the issuance of letters of credit and provide additional liquidity. The Company had used approximately $334 million of its total lines of credit for letters of credit at December 31, 2007. 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.

In February 2007, the Company established a US$2.2-billion unsecured, committed one-year bridge facility and drew down $1.5 billion and US$700 million for the sole purpose of partially financing the acquisitions of ANR and an increased ownership in Great Lakes. The facility had a floating interest rate based on the one-month LIBOR plus 25 basis points. The outstanding balance at December 31, 2007 was US$370 million, which was repaid on January 7, 2008. The undrawn balance of this facility has been cancelled and is no longer available to the Company.

NOTE 20 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 $65 million at December 31, 2007 (2006 – $39 million), calculated using an inflation rate ranging from two to three per cent per annum. The estimated fair value of these liabilities was $25 million at December 31, 2007 (2006 – $9 million) after discounting the estimated cash flows at rates ranging from 5.4 per cent to 8.0 per cent. At December 31, 2007, the expected timing of payment for settlement of the obligations ranged from one to 27 years.

The estimated undiscounted cash flows required to settle the asset retirement obligations with respect to the Energy segment were $216 million at December 31, 2007 (2006 – $162 million), calculated using an inflation rate ranging from two to three per cent per annum. The estimated fair value of this liability was $63 million at December 31, 2007 (2006 – $36 million) after discounting the estimated cash flows at rates ranging from 5.4 per cent to 6.6 per cent. At December 31, 2007, the expected timing of payment for settlement of the obligations ranges from 11 to 32 years.

Reconciliation of Asset Retirement Obligations[1]

(millions of dollars)	Pipelines	Energy	Total
Balance at January 1, 2005	5	31	36
New obligations and revisions in estimated cash flows	(1)	1	–
Sale of Power LP	–	(5)	(5)
Accretion expense	–	2	2
Balance at December 31, 2005	4	29	33
New obligations and revisions in estimated cash flows	4	6	10
Accretion expense	1	1	2
Balance at December 31, 2006	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**

[1] Asset Retirement Obligations are included in Deferred Amounts.

NOTE 21 EMPLOYEE FUTURE BENEFITS

The Company sponsors DB Plans that cover substantially all employees. 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 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 11 years.

The Company also provides its employees with DC Plans 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 14 years at December 31, 2007. Contributions to DC Plans are expensed as incurred.

The Company expensed $8 million in 2007 (2006 – $2 million; 2005 – $2 million) related to retirement savings plans for its U.S. employees.

Total cash payments for employee future benefits, consisting of cash contributed by the Company to the DB Plans and other benefit plans, was $61 million in 2007 (2006 – $104 million; 2005 – $74 million).

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, 2008, and the next required valuation will be as at January 1, 2009.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2007**	2006	**2007**	2006
Change in Benefit Obligation				
Benefit obligation – beginning of year	**1,378**	1,282	**132**	148
Current service cost	**45**	39	**2**	3
Interest cost	**73**	65	**7**	8
Employee contributions	**4**	3	**–**	–
Benefits paid	**(65)**	(64)	**(7)**	(7)
Actuarial (gain)/loss	**(22)**	53	**8**	(2)
Foreign exchange rate changes	**(16)**	–	**(6)**	–
Plan amendment	**–**	–	**–**	(18)
Acquisition	**65**	–	**19**	–
Benefit obligation – end of year	**1,462**	1,378	**155**	132
Change in Plan Assets				
Plan assets at fair value – beginning of year	**1,264**	1,096	**33**	27
Actual return on plan assets	**33**	134	**2**	6
Employer contributions	**46**	95	**7**	7
Employee contributions	**4**	3	**–**	–
Benefits paid	**(65)**	(64)	**(7)**	(7)
Foreign exchange rate changes	**(17)**	–	**(5)**	–
Acquisition	**93**	–	**–**	–
Plan assets at fair value – end of year	**1,358**	1,264	**30**	33
Funded status – plan deficit	**(104)**	(114)	**(125)**	(99)
Unamortized net actuarial loss	**299**	291	**44**	39
Unamortized past service costs	**28**	32	**7**	(12)
Accrued benefit asset/(liability), net of valuation allowance of nil	**223**	209	**(74)**	(72)

The accrued benefit asset/(liability) in the Company's balance sheet was as follows:

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2007**	2006	**2007**	2006
Other Assets	**223**	230	**5**	5
Deferred Amounts	**–**	(21)	**(79)**	(77)
Total	**223**	209	**(74)**	(72)

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)	**2007**	2006	**2007**	2006
Benefit obligation	**(1,324)**	(1,359)	**(155)**	(102)
Plan assets at fair value	**1,198**	1,243	**30**	–
Funded status – plan deficit	**(126)**	(116)	**(125)**	(102)

The Company's expected contributions in 2008 are approximately $60 million for the pension benefit plans and approximately $14 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
2008	65	7
2009	68	7
2010	71	8
2011	74	9
2012	78	9
2013 to 2017	447	54

The significant weighted average actuarial assumptions adopted in measuring the Company's benefit obligations at December 31 were as follow:

	Pension Benefit Plans		Other Benefit Plans	
	2007	2006	**2007**	2006
Discount rate	**5.30%**	5.00%	**5.50%**	5.20%
Rate of compensation increase	**3.50%**	3.50%		

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan cost for years ended December 31 were as follow:

	Pension Benefit Plans			Other Benefit Plans		
	2007	2006	2005	**2007**	2006	2005
Discount rate	**5.05%**	5.00%	5.75%	**5.20%**	5.15%	6.00%
Expected long-term rate of return on plan assets	**6.90%**	6.90%	6.90%	**7.75%**	7.75%	7.20%
Rate of compensation increase	**3.50%**	3.50%	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 the determination of 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 2008 measurement purposes. The rate was assumed to decrease gradually to five per cent in 2016 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	14	(12)

The Company's net benefit cost is as follows.

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31 (millions of dollars)	**2007**	2006	2005	**2007**	2006	2005
Current service cost	**45**	39	32	**2**	3	3
Interest cost	**73**	65	63	**7**	8	7
Actual return on plan assets	**(33)**	(134)	(119)	**(2)**	(6)	(2)
Actuarial (gain)/loss	**(22)**	53	149	**8**	(2)	21
Plan amendment	**–**	–	–	**–**	(18)	–
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**63**	23	125	**15**	(15)	29
Difference between expected and actual return on plan assets	**(51)**	63	54	**(1)**	4	–
Difference between actuarial (gain)/loss recognized and actual actuarial (gain)/loss on accrued benefit obligation	**47**	(27)	(131)	**(7)**	4	(20)
Difference between amortization of past service costs and actual plan amendments	**4**	4	3	**–**	19	1
Amortization of transitional obligation related to regulated business	**–**	–	–	**2**	2	2
Net benefit cost recognized	**63**	63	51	**9**	14	12

The Company pension plans' weighted average asset allocations and weighted average target allocations by asset category were as follow:

December 31	Percentage of Plan Assets		**Target Allocation**
Asset Category	**2007**	2006	**2007**
Debt securities	**42%**	40%	**35% to 60%**
Equity securities	**58%**	60%	**40% to 65%**
	100%	100%	

Debt securities included the Company's debt of $4 million (0.3 per cent of total plan assets) and $4 million (0.3 per cent of total plan assets) at December 31, 2007 and 2006, respectively. Equity securities included the Company's common shares of $6 million (0.4 per cent of total plan assets) and $6 million (0.5 per cent of total plan assets) at December 31, 2007 and 2006, 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 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 $34 million in 2007 (2006 – $25 million; 2005 – $4 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, 2008, and the next required valuations will be as at January 1, 2009.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2007**	2006	**2007**	2006
Change in Benefit Obligation				
Benefit obligation – beginning of year	**807**	679	**169**	81
Current service cost	**28**	24	**10**	7
Interest cost	**40**	37	**8**	5
Employee contributions	**5**	5	**–**	–
Benefits paid	**(23)**	(15)	**(2)**	(2)
Actuarial (gain)/loss	**(34)**	77	**(16)**	72
Foreign exchange rate changes	**(3)**	–	**–**	–
Acquisition	**(31)**	–	**(2)**	–
Plan amendment	**–**	–	**(2)**	6
Benefit obligation – end of year	**789**	807	**165**	169
Change in Plan Assets				
Plan assets at fair value – beginning of year	**666**	585	**–**	–
Actual return on plan assets	**(1)**	68	**–**	–
Employer contributions	**32**	23	**2**	2
Employee contributions	**5**	5	**–**	–
Benefits paid	**(23)**	(15)	**(2)**	(2)
Foreign exchange rate changes	**(5)**	–	**–**	–
Acquisition	**(48)**	–	**–**	–
Plan assets at fair value – end of year	**626**	666	**–**	–
Funded status – plan deficit	**(163)**	(141)	**(165)**	(169)
Unamortized net actuarial loss	**169**	174	**45**	66
Unamortized past service costs	**–**	–	**3**	6
Accrued benefit asset/(liability), net of valuation allowance of nil	**6**	33	**(117)**	(97)

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)	**2007**	2006	**2007**	2006
Other assets	**6**	33	**–**	–
Deferred amounts	**–**	–	**(117)**	(97)
Total	**6**	33	**(117)**	(97)

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)	**2007**	2006	**2007**	2006
Benefit obligation	**(786)**	(773)	**(165)**	(169)
Plan assets at fair value	**623**	609	**–**	–
Funded status – plan deficit	**(163)**	(164)	**(165)**	(169)

The expected contributions of the Company's joint ventures in 2008 are approximately $31 million for the pension benefit plans and approximately $3 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
2008	26	3
2009	30	4
2010	33	5
2011	37	5
2012	41	6
2013 to 2017	263	39

The significant weighted average actuarial assumptions adopted in measuring the benefit obligations of the Company's joint ventures at December 31 were as follow:

	Pension Benefit Plans		Other Benefit Plans	
	2007	2006	**2007**	2006
Discount rate	**5.25%**	5.05%	**5.15%**	4.95%
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 follow:

	Pension Benefit Plans			Other Benefit Plans		
	2007	2006	2005	**2007**	2006	2005
Discount rate	**5.00%**	5.25%	6.20%	**4.90%**	5.15%	6.25%
Expected long-term rate of return on plan assets	**7.00%**	7.30%	7.40%			
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	(1)
Effect on post-employment benefit obligation	23	(20)

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)	**2007**	2006	2005	**2007**	2006	2005
Current service cost	**28**	24	4	**10**	7	1
Interest cost	**40**	37	7	**8**	5	1
Actual return on plan assets	**1**	(68)	(18)	**–**	–	–
Actuarial (gain)/loss	**(34)**	77	17	**(16)**	72	2
Plan amendment	**–**	–	–	**(2)**	6	–
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**35**	70	10	**–**	90	4
Difference between expected and actual return on plan assets	**(44)**	26	9	**–**	–	–
Difference between actuarial (gain)/loss recognized and actual actuarial (gain)/loss on accrued benefit obligation	**44**	(70)	(16)	**20**	(72)	(3)
Difference between amortization of past service costs and actual plan amendments	**–**	–	–	**3**	(6)	–
Net benefit cost recognized related to joint ventures	**35**	26	3	**23**	12	1

The weighted average asset allocations and weighted average target allocation by asset category in the pension plans of the Company's joint ventures were as follow:

December 31	Percentage of Plan Assets		**Target Allocation**
Asset Category	**2007**	2006	**2007**
Debt securities	**43%**	29%	**40%**
Equity securities	**57%**	71%	**60%**
	100%	100%	

Debt securities included the Company's debt of $1 million (0.2 per cent of total plan assets) and $1 million (0.2 per cent of total plan assets) at December 31, 2007 and 2006, respectively. Equity securities included the Company's common shares of $3 million (0.5 per cent of total plan assets) and $6 million (1.0 per cent of total plan assets) at December 31, 2007 and 2006, 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 22 CHANGES IN OPERATING WORKING CAPITAL

Year ended December 31 (millions of dollars)	**2007**	2006	2005
Decrease/(increase) in accounts receivable	**51**	(188)	(100)
Increase in inventories	**(6)**	(108)	(50)
Decrease/(increase) in other current assets	**118**	(6)	(1)
Increase/(decrease) in accounts payable	**61**	(42)	97
(Decrease)/increase in accrued interest	**(9)**	41	5
	215	(303)	(49)

NOTE 23 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, equipment and a natural gas storage facility are approximately as follows.

Year ended December 31 (millions of dollars)	Minimum Lease Payments	Amounts Recoverable under Sub-Leases	Net Payments
2008	62	(13)	49
2009	58	(12)	46
2010	57	(12)	45
2011	61	(10)	51
2012	61	(6)	55
2013 and thereafter	848	(13)	835
Total	1,147	(66)	1,081

The operating lease agreements for premises, services and equipment expire at various dates through 2021, with an option to renew certain lease agreements for one to ten years. The operating lease agreement for the natural gas storage facility expires in 2030. The lessee has the right to terminate the agreement on anniversary dates five years apart commencing in 2010, and the lessor has the right to terminate the agreement on the same schedule commencing in 2015. Net rental expense on operating leases in 2007 was $34 million (2006 – $25 million; 2005 – $17 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 things. The amount of power purchased under the PPAs in 2007 was $440 million (2006 – $499 million; 2005 – $230 million). The generating capacities and expiry dates of the PPAs are as follow:

	Megawatts	Expiry Date
Sheerness	756	December 31, 2020
Sundance A	560	December 31, 2017
Sundance B	353	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 to third-party suppliers related to refurbishing and restarting Units 1 and 2 and refurbishing Units 3 and 4 to extend their operating life. TransCanada's share of these signed commitments, which extend over the four-year period ending December 31, 2011, are as follow:

Year ended December 31 (millions of dollars)	
2008	360
2009	151
2010	69
2011	14
	594

Aboriginal Pipeline Group

On June 18, 2003, the Mackenzie Delta gas producers, the APG and TransCanada reached an agreement governing TransCanada's role in the Mackenzie Gas Pipeline (MGP) project to build a natural gas pipeline from Inuvik, Northwest Territories, to the northern border of Alberta, where it would connect with the Company's Alberta System. Under the agreement, TransCanada agreed to finance the APG for its one-third share of project pre-development costs. These costs are currently forecasted to be between $150 million and $200 million, depending on the pace of project development. As at December 31, 2007, the Company had advanced $137 million of this total.

TransCanada and the other co-venture companies involved in the MGP continue to pursue approval of the proposed project, focusing on the regulatory process and discussions with the Canadian government on the fiscal framework. Project timing is uncertain and is conditional upon resolution of regulatory and fiscal matters. TransCanada's ability to recover its investment depends on the successful outcome of the project.

Other Commitments

TransCanada is committed to capital expenditures of approximately $1.6 billion related to its share of the construction costs of the Keystone oil pipeline and other pipeline projects.

The Company is committed to capital expenditures of approximately $608 million related to its share of the construction costs of the Halton Hills, Portlands Energy and remaining Cartier Wind projects.

Contingencies

The Canadian Alliance of Pipeline Landowners' Associations (CAPLA) and two individual landowners commenced an action in 2003 against TransCanada and Enbridge Inc. under Ontario's *Class Proceedings Act, 1992* for damages of $500 million. The damages are alleged to have arisen from the creation of a control zone within 30 metres of a pipeline pursuant to Section 112 of the *National Energy Board Act*. In November 2006, TransCanada and Enbridge Inc. were granted a dismissal of the case but CAPLA appealed the decision. The Ontario Court of Appeal heard the appeal on December 18, 2007, and reserved its decision. The Company continues to believe the claim is without merit and will vigorously defend the action. The Company has made no provision for any potential liability. A liability, if any, would be dealt with through the regulatory process.

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 each severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, operator licenses, a lease agreement and contractor services. The guarantees have terms ranging from one year ending in 2008 to perpetuity.

TransCanada and BPC have each 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 part of the reorganization of Bruce Power in 2005 and have terms ending in 2019 to 2036. TransCanada's share of the potential exposure under these Bruce Power guarantees was estimated at December 31, 2007 to range from $711 million to a maximum of $750 million. The fair value of these guarantees is estimated to be $12 million.

The Company and its partners in certain jointly owned entities have severally and joint and severally guaranteed the performance of these entities related primarily to construction projects, 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, 2007 to range from $699 million to a maximum of $1,210 million. 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. Deferred Amounts includes $7 million for the fair value of these joint and several guarantees.

TransCanada has guaranteed a subsidiary's equity undertaking that supports the payment, under certain conditions, of principal and interest on US$75 million of the public debt obligations of TransGas de Occidente S.A. (TransGas). The Company has a 46.5 per cent interest in TransGas. Under the terms of a shareholder agreement, TransCanada and another major multinational company, may be required to severally fund more than their proportionate share of debt obligations of TransGas in the event that the minority shareholders fail to contribute. Any payments made by TransCanada under this agreement convert into share capital of TransGas. The Company's potential exposure is contingent on the impact any change of law would have on the ability of TransGas to service the debt. There has been no change in applicable law since the issuance of debt in 1995 and, thus, no exposure for TransCanada. The debt matures in 2010. The Company has made no provision related to this guarantee.

NOTE 24 DISCONTINUED OPERATIONS

TransCanada had no income from discontinued operations in 2007 (2006 – $28 million; 2005 – nil). The income from discontinued operations in 2006 reflected settlements received from bankruptcy claims related to TransCanada's Gas Marketing business, which was divested in 2001.

NOTE 25 SUBSEQUENT EVENTS

Certain subsidiaries of Calpine filed for bankruptcy protection in both Canada and the U.S. in 2005. Portland and Gas Transmission Northwest Corporation (GTNC) have reached agreements with Calpine for allowed unsecured claims of US$125 million and US$192.5 million, respectively, in the Calpine bankruptcy. Creditors will receive shares in the re-organized Calpine and these shares will be subject to market price fluctuations as the new Calpine shares begin to trade. In February 2008, Portland and GTNC received initial distributions of 6.1 million shares and 9.4 million shares, respectively, which are expected to result in a significant increase in TransCanada's net earnings in first-quarter 2008.

Claims by NGTL and Foothills Pipe Lines (South B.C.) Ltd. for $31.6 million and $44.4 million, respectively, were received in cash in January 2008 and will be passed on to shippers on these systems.