2008

Management's Discussion and Analysis and Audited Consolidated Financial Statements

TransCanada PipeLines Limited

TransCanada
In business to deliver

PIPELINES

Natural Gas Pipelines

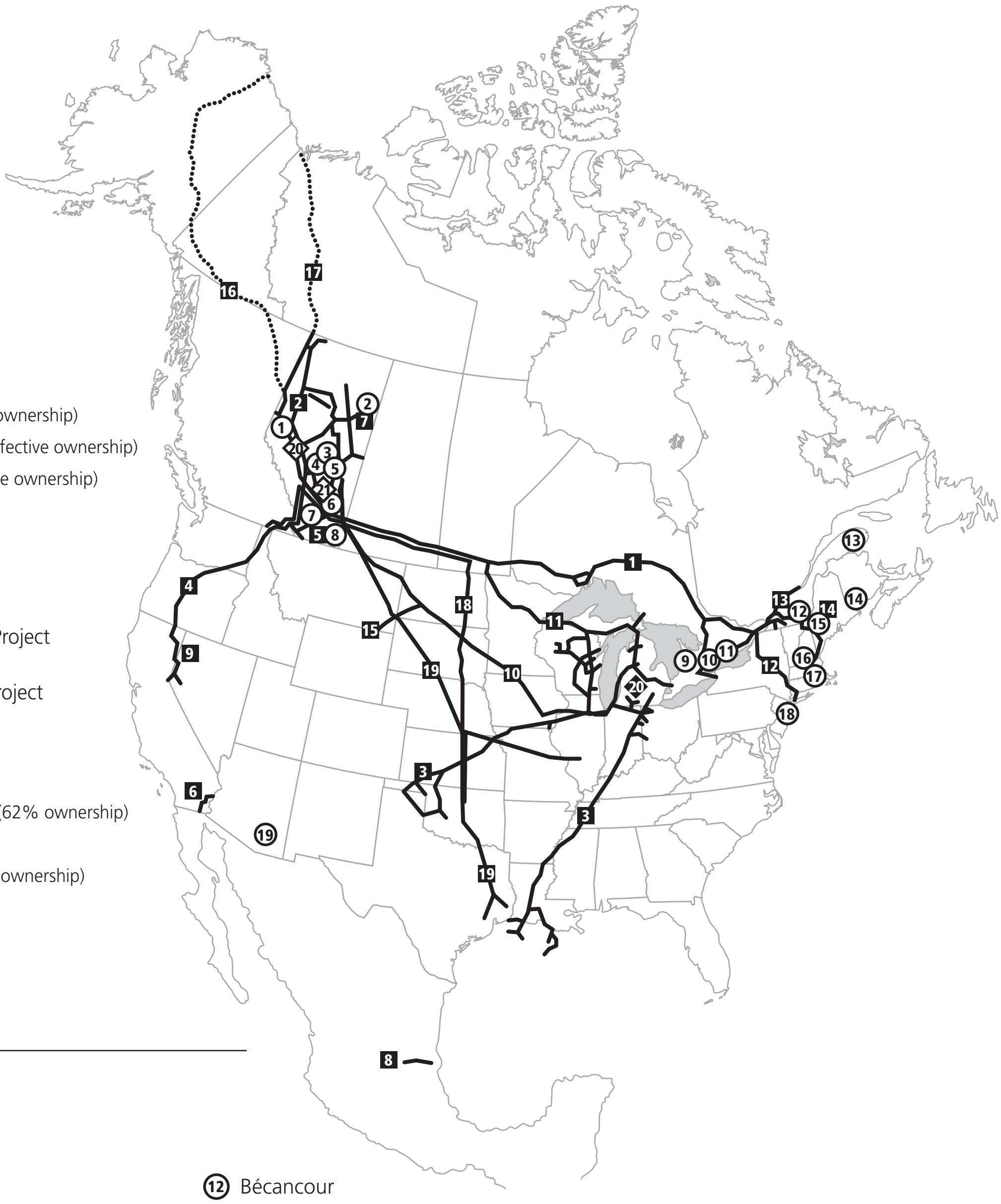
- **1** Canadian Mainline
- **2** Alberta System
- **3** ANR
- **4** GTN System
- **5** Foothills
- **6** North Baja
- **7** Ventures LP
- **8** Tamazunchale
- **9** Tuscarora (32.1% effective ownership)
- **10** Northern Border (16.1% effective ownership)
- **11** Great Lakes (68.5% effective ownership)
- **12** Iroquois (44.5% ownership)
- **13** TQM (50% ownership)
- **14** Portland (61.7% ownership)
- **15** Bison (in development)
- **16** Alaska Highway Pipeline Project (proposed by TransCanada)
- **17** Mackenzie Gas Pipeline Project (proposed by producers)

Oil Pipeline

- **18** Keystone Pipeline Project (62% ownership) (under construction)
- **19** Keystone Expansion (62% ownership) (in developement)

Natural Gas Storage

- **20** ANR Natural Gas Storage



ENERGY

Power Generation

1. Bear Creek
2. MacKay River
3. Redwater
4. Sundance A PPA
5. Sundance B PPA (50% ownership)
6. Sheerness PPA
7. Carseland
8. Cancarb
9. Bruce Power (Bruce A – 48.9%, Bruce B – 31.6%)
10. Halton Hills (under construction)
11. Portlands Energy (50% ownership) (under construction)
12. Bécancour
13. Cartier Wind (62% ownership, under construction)
14. Grandview
15. Kibby Wind (under construction)
16. TC Hydro
17. OSP
18. Ravenswood
19. Coolidge (in development)

Gas Storage

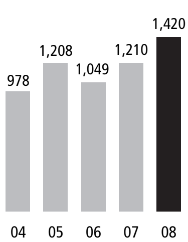
- **20** Edson
- **21** CrossAlta (60% ownership)

Financial Highlights

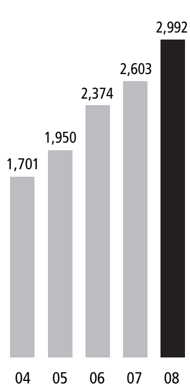
Year ended December 31 *(millions of dollars)*	2004	2005	2006	2007	**2008**
Income					
Comparable Earnings[1]	791	838	923	1,087	**1,259**
Net income applicable to common shares	1,030	1,208	1,077	1,210	**1,420**
Cash Flow					
Funds generated from operations	1,701	1,950	2,374	2,603	**2,992**
(Increase)/decrease in operating working capital	28	(48)	(300)	215	**(188)**
Net cash provided by continuing operations	1,729	1,902	2,074	2,818	**2,804**
Capital expenditures and acquisitions	2,046	2,071	2,042	5,874	**6,363**
Balance Sheet					
Total assets	22,421	24,113	26,386	31,737	**40,935**
Long-term debt	9,749	9,640	10,887	12,377	**15,368**
Junior subordinated notes	–	–	–	975	**1,213**
Common shareholders' equity	6,484	7,164	7,618	9,664	**12,574**

(1) Non-GAAP measure that does not have any standardized meaning prescribed by generally accepted accounting principles. For more information on non-GAAP measures see page 11 in the Management's Discussion and Analysis of the 2008 Annual Report.

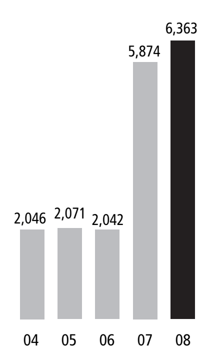
Net Income Applicable to Common Shares from Continuing Operations
(millions of dollars)



Funds Generated from Operations
(millions of dollars)



Capital Expenditures and Acquisitions
(millions of dollars)



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The Management's Discussion and Analysis (MD&A) dated February 23, 2009 should be read in conjunction with the audited Consolidated Financial Statements of TransCanada PipeLines Limited (TCPL or the Company) and the notes thereto for the year ended December 31, 2008, which are prepared in accordance with Canadian generally accepted accounting principles (GAAP). This MD&A covers TCPL's financial position and operations as at and for the year ended December 31, 2008. 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 2008 Annual Report.

TCPL OVERVIEW

In 2008, TCPL celebrated the 50th anniversary of the completion of its original pipeline from Alberta to Ontario and Québec. Fifty years of experience has established TCPL as a significant player in the development and operation of North American energy infrastructure, including natural gas and oil pipelines, power generation plants, and natural gas storage facilities.

TCPL has invested approximately $24 billion in capital projects in the last nine years, and currently has more than $40 billion in total assets. The Company is currently executing an $18 billion capital program and most of the projects are expected to be completed by 2012. Over the longer term, TCPL intends to continue to pursue and develop its substantial portfolio of large-scale infrastructure projects. TCPL is committed to maintaining the financial strength required to build the energy infrastructure needed to serve increased energy demand, respond to shifting energy supply-demand dynamics and replace aging North American infrastructure.

Pipelines Assets

The TCPL network of more than 59,000 kilometres (km) (36,661 miles) of wholly owned and 7,800 km (4,847 miles) of partially owned natural gas pipelines connect virtually every major natural gas supply basin and market, transporting 20 per cent of the natural gas consumed in North America. TCPL's natural gas pipelines link gas supplies from Western Canada, the United States (U.S.) mid-continent and Gulf of Mexico to premium North American markets. These assets are well positioned to connect emerging natural gas supplies, including northern gas, northeastern British Columbia (B.C.) and U.S. shale gas, and offshore liquefied natural gas (LNG) imports, to growing markets.

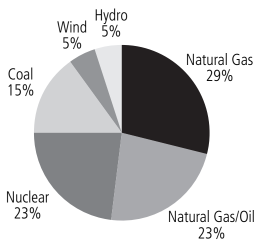
TCPL's Alberta System gathered 66 per cent of the natural gas produced in Western Canada or 15 per cent of total North American production in 2008. TCPL exports natural gas from the Western Canada Sedimentary Basin (WCSB) to Eastern Canada and the U.S. West, Midwest, and Northeast through three wholly owned pipeline systems: the Canadian Mainline, the GTN System and Foothills. TCPL 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, Iroquois, Portland, TQM, Northern Border and Tuscarora. Certain of these pipeline systems are held through the Company's 32.1 per cent interest in TC PipeLines, LP (PipeLines LP).

ANR was acquired in February 2007. ANR transports natural gas from producing fields located primarily in Oklahoma, Texas, Louisiana and the Gulf of Mexico to markets located in Wisconsin, Michigan, Illinois, Ohio and Indiana. It also connects with numerous other natural gas pipelines, providing customers with access to diverse sources of North American supply, including Western Canada and the Rocky Mountain region, and to a variety of end-user markets in the midwestern and northeastern U.S. ANR owns and operates 250 billion cubic feet (Bcf) of regulated natural gas storage capacity in Michigan.

In addition, the Company has agreed to increase its ownership interest up to 79.99 per cent in each of TransCanada Keystone Pipeline Limited Partnership and TransCanada Keystone Pipeline, LP (collectively, Keystone partnerships). TCPL has partnered with ConocoPhillips, a global, integrated oil and gas producer and refiner to build the Keystone crude oil pipeline. Currently under construction, the Keystone pipeline will transport 1.1 million barrels per day (Bbl/d) of crude oil from Hardisty, Alberta to U.S. Midwest markets at Wood River and Patoka in Illinois, and at Cushing, Oklahoma, and to U.S. Gulf Coast markets. The pipeline is supported by long-term contracts with strong counterparties and provides a low-cost shipping option. While the current economic slowdown and low oil price environment have eased the pace of oil sands project activity, developments in the medium to long term in Alberta will provide attractive opportunities for further additions to crude oil transmission infrastructure.

Energy Assets
TCPL's Energy business has grown from 754 megawatts (MW) in 1999 to more than 10,900 MW in 2008. The Company's diverse power generation portfolio of primarily low-cost, baseload or long-term contracted facilities comprises a total of 19 plants in Alberta, Eastern Canada, New England, and New York City. The accompanying graph illustrates each fuel source as a percentage of the Company's overall Energy portfolio:

Power by Fuel Source



TCPL has developed a significant non-regulated natural gas storage business in Alberta where the Company 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.

TCPL'S STRATEGY

TCPL'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 it has or can develop significant competitive advantage. Since 2000, TCPL's key strategies continue to evolve with the Company's growth and development and its changing business environment. TCPL's corporate strategy integrates five fundamental value-creating activities:

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

These strategies are defined by an integrated set of activities and performance objectives:

Maximize the full-life value of TCPL's infrastructure assets and commercial positions
TCPL relies on a low-risk business model to maximize the full-life value of existing assets and positions that generate predictable, sustainable streams of cash flows and earnings. In the Company's Pipelines business, the natural gas pipeline network connects traditional and emerging basins to growing markets offering effective service and competitive rates. TCPL's Energy business supplies growing power markets through long-term power purchase agreements, and low-cost baseload generation. The Company's activities in gas, nuclear, wind and hydro energy sources demonstrate its commitment to a sustainable energy future. TCPL continues to make its long-term commercial and physical asset operations a priority. The Company attempts to maximize the life and value of its assets by focusing on sustainable business initiatives derived from engaging in market and regulatory developments, combined with an accretive capital investment program.

Cultivate a focused portfolio of high quality development options
The Company's core western and eastern regions are the primary focus of growth initiatives in the Pipelines and Energy businesses. Consideration is given to new markets with good fundamentals where TCPL has or can develop competitive strengths. There is a continued focus on low-cost, baseload power assets as well as on power and natural gas storage assets supported by firm, long-term contracts with reputable counterparties. Greenfield development and acquisition of power generation, power transmission and natural gas storage are considered if they meet the Company's investment

standards. Greenfield and brownfield pipeline projects are being pursued to diversify the Pipelines business and add incremental value to existing assets. Key areas of focus include greenfield development options to connect the Company's natural gas pipelines to northern gas reserves and emerging Canadian and U.S. shale gas supplies, and transporting crude oil from the Alberta oil sands. Other possible growth opportunities include acquiring natural gas and oil transmission assets that complement TCPL's existing assets, acquiring partners' interests in associated pipelines and acquiring stand-alone transmission enterprises in new regions of North America.

Commercially develop and physically execute new asset investment programs
TCPL's current $18 billion capital program is expected to begin generating revenue over the next four years beginning in 2009. The Company is committed to completing the projects in its capital programs on time and on budget to deliver service to its customers and returns to its shareholders. Its large portfolio of projects is characterized by highly contracted, long-term revenue streams and limited exposure to capital cost risks. These are key features of TCPL's model for managing construction risks and improving the return realized from new investment programs. This strategy will be applied to Pipelines and Energy growth opportunities that address North America's emerging energy infrastructure needs.

Maximize TCPL's competitive strengths
TCPL will use its competitive strengths to achieve responsible, profitable operations and growth. In the Pipelines and Energy infrastructure businesses, size and scale of operations must be large enough to compete effectively and offer recognized value to customers. The Company believes its competitive strengths include the discipline it applies in operations, governance and project, financial and risk management, and its ability to obtain capital at suitable terms. TCPL strives to provide customers with safe, low-cost, reliable and responsible service by such means as improved efficiencies, operational reliability and enhanced environmental and safety performance. The Company also strives to maintain constructive relationships with its key stakeholder groups. Utilizing these strengths is the responsibility of all employees, and all employees contribute to the success of the Company. To maximize the quality, capability and contribution of the Company's employees, management encourages and supports its employees' innovative thinking, development and leadership.

Maximize TCPL's financial strength and reputation
TCPL continues to value its reputation for financial strength based on a history of predictable, growing earnings and cash flow. The Company continues to communicate its financial performance to current and prospective debt and equity holders, while making its management of risks transparent. TCPL strives to maintain access to low-cost capital in all market environments to enable it to capture growth opportunities and improve its financial performance.

CONSOLIDATED FINANCIAL REVIEW

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

	2008	2007	2006
Income Statement			
Revenues	**8,619**	8,828	7,520
Net income applicable to common shares			
Continuing operations	**1,420**	1,210	1,049
Discontinued operations	**–**	–	28
	1,420	1,210	1,077
Comparable earnings[1]	**1,259**	1,087	923
Per Common Share Data			
Net income – basic and diluted			
Continuing operations	**$2.59**	$2.33	$2.17
Discontinued operations	**–**	–	0.06
	$2.59	$2.33	$2.23
Summarized Cash Flow			
Funds generated from operations[1]	**2,992**	2,603	2,374
(Increase)/decrease in operating working capital	**(188)**	215	(300)
Net cash provided by operations	**2,804**	2,818	2,074
Balance Sheet			
Total assets	**40,935**	31,737	26,386
Total long-term liabilities	**20,422**	17,832	15,014

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

HIGHLIGHTS

Net Income

- Net income applicable to common shares was $1,420 million in 2008 compared to net income applicable to common shares of $1,210 million in 2007.

Comparable Earnings

- TCPL's comparable earnings of $1,259 million in 2008 excluded $152 million of gains from bankruptcy settlements with certain subsidiaries of Calpine Corporation (Calpine), proceeds of $10 million from a lawsuit settlement, a $27 million writedown of costs for the Broadwater LNG project (Broadwater) and $26 million of favourable income tax adjustments. Comparable earnings of $1,087 million in 2007 excluded favourable income tax adjustments of $102 million, a gain of $14 million on the sale of land and $7 million of net unrealized gains from changes in the fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts.

Cash from Operations

- Net cash provided by operations was $2,804 million in 2008, a decrease of $14 million from 2007.
- Funds generated from operations were $2,992 million in 2008, an increase of $389 million or 15 per cent from 2007.

Investing Activities

- TCPL invested $6.4 billion in its Pipelines and Energy businesses in 2008, including the following:
  - the acquisition of the Ravenswood facility in August 2008 for US$2.9 billion, subject to certain post-closing adjustments;
  - capital expenditures of $1.8 billion for Pipelines projects, including Keystone and North Central Corridor; and
  - capital expenditures of $1.3 billion for Energy projects, including the Bruce A restart of Units 1 and 2, and construction of Portlands Energy, Halton Hills, Kibby Wind and Cartier Wind.

Financing Activities

- In 2008, TCPL issued $2.2 billion of long-term debt (net of issue costs) and $2.4 billion of common shares, comprised primarily of the following:
  - in 2008, the issuance of 66.3 million common shares to TransCanada Corporation (TransCanada), resulting in gross proceeds of approximately $2.4 billion;
  - in August 2008, the issuance of US$1.5 billion of Senior Unsecured Notes; and
  - in August 2008, the issuance of $500 million of Medium-Term Notes.
- In February 2009, the Company issued $700 million of Medium-Term Notes.
- In January 2009, the Company issued US$2.0 billion of Senior Unsecured Notes.
- In November 2008, TCPL established a new US$1.0 billion committed bank facility.
- In June 2008, the Company entered into an agreement for a US$1.5 billion one-year bridge loan facility. In August 2008, the Company drew US$255 million and cancelled the remainder of the commitment.

Balance Sheet

- Total assets increased by $9.2 billion to $40.9 billion in 2008 compared to 2007, primarily due to the acquisition of the Ravenswood facility, investments in Energy and Pipelines capital projects, and the effect of a stronger U.S. dollar.
- TCPL's shareholders' equity increased by $2.9 billion to $13.0 billion in 2008 compared to the previous year.

Dividend

- On February 2, 2009, TCPL's Board of Directors declared a dividend for the quarter ending March 31, 2009 in an aggregate amount equal to the quarterly dividend to be paid on TransCanada's issued and outstanding common shares at the close of business on March 31, 2009. The Board also declared regular dividends on TCPL's preferred shares.

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

SEGMENT RESULTS
Reconciliation of Comparable Earnings to Net Income Applicable to Common Shares
Year ended December 31
(millions of dollars except per share amounts)

	2008	2007	2006
Pipelines			
Comparable earnings	**740**	686	529
Specific items (net of tax):			
Calpine bankruptcy settlements	**152**	–	–
GTN lawsuit settlement	**10**	–	–
Bankruptcy settlement with Mirant	**–**	–	18
Gain on sale of Northern Border Partners, L.P. interest	**–**	–	13
Net earnings	**902**	686	560
Energy			
Comparable earnings	**641**	459	429
Specific items (net of tax, where applicable):			
Writedown of Broadwater costs	**(27)**	–	–
Gain on sale of land	**–**	14	–
Fair value adjustments of natural gas storage inventory and forward contracts	**–**	7	–
Income tax reassessments and adjustments	**–**	34	23
Net earnings	**614**	514	452
Corporate			
Comparable expenses	**(122)**	(58)	(35)
Specific item:			
Income tax reassessments and adjustments	**26**	68	72
Net (expenses)/earnings	**(96)**	10	37
Net Income Applicable to Common Shares			
Continuing operations(1)	**1,420**	1,210	1,049
Discontinued operations	**–**	–	28
Net Income Applicable to Common Shares	**1,420**	1,210	1,077
Comparable Earnings(1)	**1,259**	1,087	923
Net Income Per Common Share – Basic			
Continuing operations	**$2.59**	$2.33	$2.17
Discontinued operations	**–**	–	0.06
	$2.59	$2.33	$2.23

(1) **Comparable Earnings**	**1,259**	1,087	923
Specific items (net of tax, where applicable):			
Calpine bankruptcy settlements	**152**	–	–
GTN lawsuit settlement	**10**	–	–
Writedown of Broadwater costs	**(27)**	–	–
Gain on sale of land	**–**	14	–
Fair value adjustments of natural gas storage inventory and forward contracts	–	7	–
Bankruptcy settlement with Mirant	**–**	–	18
Gain on sale of Northern Border Partners, L.P. interest	**–**	–	13
Income tax reassessments and adjustments	**26**	102	95
Net Income Applicable to Common Shares from Continuing Operations	**1,420**	1,210	1,049

RESULTS OF OPERATIONS

Net income applicable to common shares and net income applicable to common shares from continuing operations (net earnings) were $1,420 million in 2008 compared to $1,210 million in 2007. Net income applicable to common shares and net earnings in 2006 were $1,077 million and $1,049 million, respectively. Results in 2006 included net income from discontinued operations of $28 million, reflecting bankruptcy settlements with Mirant Corporation and certain of its subsidiaries (Mirant) related to their transactions with TCPL's Gas Marketing business. TCPL divested its Gas Marketing business in 2001.

Net income applicable to common shares in 2008 included $152 million of after-tax gains on shares received by the GTN System and Portland from the Calpine bankruptcy settlements, $10 million after tax of GTN System lawsuit settlement proceeds and a $27 million after-tax writedown of costs previously capitalized for Broadwater. Net income applicable to common shares in 2008 also included $26 million of favourable income tax adjustments from an internal restructuring and realization of losses. Net income applicable to common shares in 2007 included $102 million ($68 million in Corporate and $34 million in Energy) of favourable income tax adjustments recorded in 2007 relating to changes in Canadian federal and provincial corporate income tax legislation, the resolution of certain tax matters and an internal restructuring. Net income applicable to common shares in 2007 also included an after-tax gain of $14 million on the sale of land and $7 million after tax of net unrealized gains resulting from changes in the fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts. Net earnings in 2006 included $95 million of favourable income tax adjustments, proceeds from an $18 million after-tax bankruptcy settlement with Mirant and an after-tax gain of $13 million from the sale of TCPL's general partner interest in Northern Border Partners, L.P.

Excluding the above-noted items, comparable earnings for 2008, 2007 and 2006 were $1,259 million, $1,087 million and $923 million, respectively. Comparable earnings in 2008 increased $172 million compared to 2007 due to higher earnings in the Energy and Pipelines businesses, partially offset by an increase in net expenses in Corporate. Pipelines' earnings increased in 2008 compared to 2007 primarily due to a full year of earnings in 2008 from ANR. Energy's earnings from Western Power, Eastern Power and Bruce A and Bruce B (collectively, Bruce Power) operations increased in 2008 compared to 2007 primarily due to higher realized prices. Corporate net expenses in 2008 increased from 2007 primarily due to unrealized losses from the changes in the fair value of derivatives, which are used to manage TCPL's exposure to rising interest rates but do not qualify for hedge accounting, and higher financial charges.

Comparable earnings increased $164 million in 2007 compared to 2006 primarily due to additional earnings from the acquisition of ANR in February 2007, a full year of earnings in 2007 from the Bécancour and Edson facilities, and positive impacts from rate case settlements for the GTN System and Canadian Mainline. These increases were partially offset by a lower contribution from Bruce Power in 2007.

Results in 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. Forward-looking statements in this document are intended to provide TCPL shareholders and potential investors with information regarding TCPL and its subsidiaries, including management's assessment of TCPL's and its subsidiaries' future financial and operational plans and outlook. Forward-looking statements in this document may include, among others, statements regarding the anticipated business prospects and financial performance of TCPL and its subsidiaries, expectations or projections about the future, strategies and goals for growth and expansion, expected and future cash flows, costs, schedules, operating and financial results and expected impact of future commitments and contingent liabilities. All forward-looking statements reflect TCPL's beliefs and assumptions based on information available at the time the statements were made. Actual results or events may differ from those predicted in these forward-looking statements. Factors that could cause actual results or events to differ materially from current expectations include, among others, the ability of TCPL 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 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, including those material risks discussed in the "Pipelines", "Energy" and "Risk Management and Financial Instruments" sections in this MD&A, which could cause TCPL'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 TCPL 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. TCPL 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

TCPL uses the measures "comparable earnings", "funds generated from operations" and "operating income" in this MD&A. These measures do not have any standardized meaning prescribed by Canadian 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 TCPL uses these non-GAAP measures to improve its ability to compare financial results among reporting periods and to enhance its understanding of operating performance, liquidity and ability to generate funds to finance operations. These non-GAAP measures are also provided to readers as additional information on TCPL's operating performance, liquidity and ability to generate funds to finance operations.

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

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

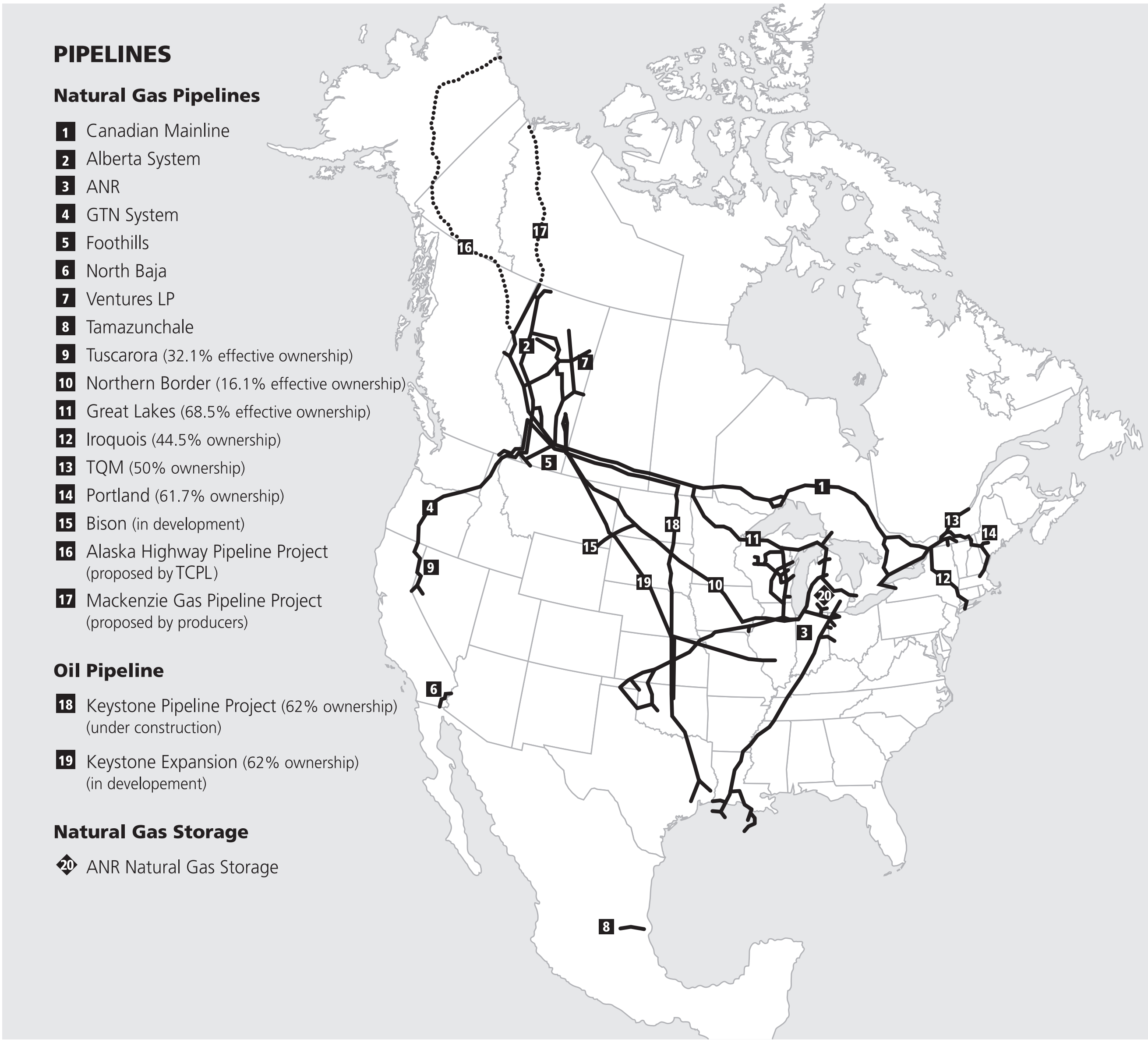
Operating income is reported in the Company's Energy business segment and comprises revenues less operating expenses as shown on the Consolidated Income Statement. A reconciliation of operating income to net income is presented in the "Energy" section of this MD&A.

OUTLOOK

TCPL's corporate strategy is underpinned by a long-term focus on growing its Pipelines and Energy businesses in a disciplined and measured manner. In 2009 and beyond, TCPL expects its net earnings and cash flow, combined with a strong balance sheet and proven access to capital markets, to provide the financial strength TCPL will need to complete its current capital expenditure program and continue to pursue other long-term growth opportunities and create additional value for its shareholders in the same disciplined and measured manner utilized in developing its current capital expenditure program. TCPL believes this prudence is especially important in the economic environment that currently exists in North America. In 2009, the Company will continue to implement its strategy and grow the Pipelines and Energy businesses as discussed in the "TCPL's Strategy" section of this MD&A.

The current economic slowdown is not expected to have a significant impact on TCPL's near-term earnings as the majority of TCPL's operations are underpinned by either long-term contracts or earn a regulated return. In addition, TCPL's continued focus on risk management is expected to further lessen the negative impact of the current economic slowdown to TCPL.

The Company's results in 2009 may be affected positively or negatively by a number of factors and developments as discussed throughout this MD&A, including without limitation, the factors and developments discussed in the "Forward-Looking Information", "Pipelines – Business Risks" and "Energy – Business Risks" sections. Refer to the "Pipelines – Outlook", "Energy – Outlook" and "Corporate – Outlook" sections of this MD&A for further discussion of outlook.



CANADIAN MAINLINE Owned 100 per cent by TCPL, the Canadian Mainline is a 14,101 km (8,762 miles) 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 TCPL, the Alberta System is a 23,705 km (14,730 miles) 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 and with the natural gas pipelines of other companies.

ANR Owned 100 per cent by TCPL, ANR is a 17,000 km (10,563 miles) transmission system that 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 providing 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 250 Bcf.

GTN SYSTEM Owned 100 per cent by TCPL, the GTN System is a 2,174 km (1,351 miles) 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 TCPL, the 1,241 km (771 miles) 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.

NORTH BAJA Owned 100 per cent by TCPL, the North Baja natural gas transmission system extends 129 km (80 miles) 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.

VENTURES LP Owned 100 per cent by TCPL, Ventures LP is comprised of a 161 km (100 miles) pipeline and related facilities that supply natural gas to the oil sands region near Fort McMurray, Alberta as well as a 27 km (17 miles) pipeline that supplies natural gas to a petrochemical complex at Joffre, Alberta.

TAMAZUNCHALE Owned 100 per cent by TCPL, the 130 km (81 miles) 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.

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

NORTHERN BORDER Owned 50 per cent by PipeLines LP, the 2,250 km (1,398 miles) Northern Border natural gas transmission system serves the U.S. Midwest from a connection with Foothills near Monchy, Saskatchewan. TCPL operates Northern Border and effectively owns 16.1 per cent of the system through its 32.1 per cent interest in PipeLines LP.

GREAT LAKES Owned 53.6 per cent by TCPL and 46.4 per cent by PipeLines LP, the 3,404 km (2,115 miles) 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. TCPL 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, which it has through its 32.1 per cent interest in PipeLines LP.

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

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

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

BISON The Bison pipeline project is a proposed 480 km (298 miles) pipeline from the Powder River Basin in Wyoming to the Northern Border system in North Dakota.

KEYSTONE Keystone is an oil pipeline consisting of 3,456 km (2,147 miles) of pipe under construction that will initially transport crude oil from Hardisty, Alberta to U.S. Midwest markets at Wood River and Patoka in Illinois, and to Cushing, Oklahoma. In addition, an expansion to the U.S. Gulf Coast is under development, which is expected to add approximately 2,720 km (1,690 miles) of pipe to the system. Commissioning of the segment to Wood River and Patoka is expected to begin in late 2009. Commissioning of the segment to Cushing is expected to begin in late 2010. The expansion to the U.S. Gulf Coast is expected to be commissioned in 2012, subject to regulatory approvals. In 2008, TCPL agreed to increase its ownership interest in Keystone up to 79.99 per cent. At December 31, 2008, TCPL owned 62 per cent of Keystone.

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

GAS PACIFICO/INNERGY Owned 30 per cent by TCPL, Gas Pacifico is a 540 km (336 miles) natural gas pipeline extending from Loma de la Lata, Argentina to Concepción, Chile. TCPL 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.

PIPELINES – HIGHLIGHTS

- Net income from Pipelines was $902 million in 2008, an increase of $216 million from $686 million in 2007. Comparable earnings from Pipelines were $740 million in 2008, an increase of $54 million from $686 million in 2007.
- The Keystone partnerships began building the portion of the Keystone pipeline that will deliver oil to markets in the U.S. Midwest and to Cushing, Oklahoma, and secured shipping commitments for a future expansion to serve markets on the U.S. Gulf Coast.
- TCPL began construction of the North Central Corridor expansion at a cost of approximately $925 million following approval from the Alberta Utilities Commission (AUC).
- TCPL received approval from the AUC for the Alberta System's 2008-2009 Revenue Requirement Settlement.
- TCPL filed an application with the National Energy Board (NEB) to establish federal jurisdiction over the Alberta System. A decision is expected in first quarter 2009.
- ANR completed the second phase of its storage enhancement project (STEP 2008), which added 14 Bcf of storage capacity.
- TCPL was awarded a license from the State of Alaska to construct the Alaska Pipeline Project under the *Alaska Gasline Inducement Act* (AGIA).

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

	2008	2007	2006
Wholly Owned Pipelines			
Canadian Mainline	**278**	273	239
Alberta System	**145**	138	136
ANR(1)	**132**	104	n/a
GTN	**65**	58	46
Foothills	**24**	26	27
	644	599	448
Other Pipelines			
Great Lakes(2)	**44**	47	44
PipeLines LP(3)	**25**	18	4
Iroquois	**18**	15	15
Tamazunchale(4)	**16**	10	2
Other(5)	**34**	46	51
Northern Development	**(9)**	(7)	(5)
General, administrative, support costs and other	**(32)**	(42)	(30)
	96	87	81
Comparable Earnings(6)	**740**	686	529
Calpine bankruptcy settlements(7)	**152**	–	–
GTN lawsuit settlement	**10**	–	–
Bankruptcy settlement with Mirant	**–**	–	18
Gain on sale of Northern Border Partners, L.P. interest	**–**	–	13
Net Earnings	**902**	686	560

(1) ANR's results include earnings from the date of acquisition of February 22, 2007.

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

(3) PipeLines LP's results include TCPL's effective ownership of an additional 14.9 per cent interest in Great Lakes since February 22, 2007 as a result of PipeLines LP's acquisition of a 46.4 per cent interest in Great Lakes and TCPL's 32.1 per cent interest in PipeLines LP. Prior to this date, TCPL had a 13.4 per cent ownership interest in PipeLines LP.

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

(5) Other includes results of Portland, Ventures LP, TQM, TransGas and Gas Pacifico/INNERGY.

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

(7) GTN and Portland received shares of Calpine with an initial after-tax value of $95 million and $38 million (TCPL's share), respectively, from the bankruptcy settlements with Calpine. These shares were subsequently sold for an additional after-tax gain of $19 million.

Net earnings from the Pipelines business were $902 million in 2008 compared to $686 million in 2007 and $560 million in 2006. Comparable earnings from the Pipelines business of $740 million in 2008 excluded the $152 million after-tax ($279 million pre-tax) gains received by Portland and the GTN System from the bankruptcy settlements with Calpine and $10 million after-tax ($17 million pre-tax) proceeds received by GTN from a lawsuit settlement with a software supplier. The $54 million increase in comparable earnings in 2008 from 2007 was primarily due to a full year of earnings from ANR, the Alberta System rate settlement and higher earnings for the Canadian Mainline. Comparable earnings in 2006 were $529 million and excluded an $18 million bankruptcy settlement with

Mirant and a $13 million gain on sale of TCPL's general partner interest in Northern Border Partners, L.P. The increase in comparable earnings in 2007 compared to 2006 was primarily due to the acquisitions of ANR and additional interest in Great Lakes, higher earnings as a result of rate settlements for Canadian Mainline and the GTN System, and an increased ownership in PipeLines LP.

PIPELINES – FINANCIAL ANALYSIS

Canadian Mainline

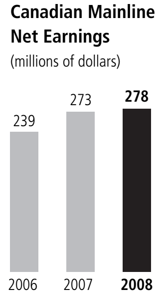
The Canadian Mainline is regulated by the NEB, which sets tolls that provide TCPL with the opportunity to recover projected costs of transporting natural gas, including a return on the Canadian Mainline's average investment base. The NEB also approves new facilities before construction begins. Net earnings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

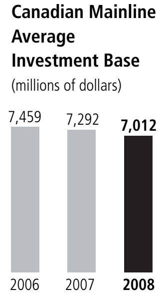
The Canadian Mainline currently operates under a five-year tolls settlement effective from 2007 to 2011. The cost of capital reflects an ROE as determined by the NEB's ROE formula on deemed common equity of 40 per cent. The remaining capital structure consists of short- and long-term debt, following the agreed upon redemption of the US$460 million 8.25 per cent Preferred Securities in 2007.

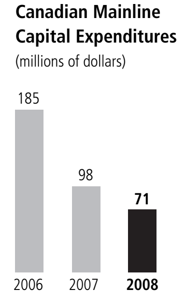
The settlement also established certain elements of the Canadian Mainline's fixed operating, maintenance and administration (OM&A) costs for each of the five years. The variance between actual and agreed-upon OM&A costs accrues entirely to TCPL from 2007 to 2009, and will be shared equally between TCPL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

Net earnings of $278 million in 2008 were $5 million higher than $273 million in 2007 primarily due to higher performance-based incentives earned and increased OM&A cost savings and an ROE of 8.71 per cent in 2008, as determined by the NEB, compared to 8.46 per cent in 2007. These increases were partially offset by a lower average investment base.

Net earnings of $273 million in 2007 were $34 million higher than $239 million in 2006. The increase primarily reflected the positive impact of the increase in deemed common equity ratio to 40 per cent from 36 per cent as a result of the Canadian Mainline tolls settlement, performance-based incentives earned and OM&A cost savings. These increases were partially offset by a lower allowed ROE of 8.46 per cent in 2007 (2006 – 8.88 per cent) and a lower average investment base.







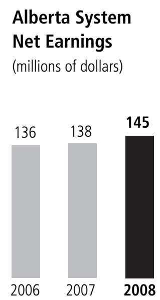
Alberta System

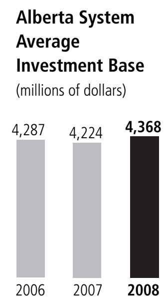
Construction and operation of the Alberta System's facilities and the terms and conditions of its services, including rates, are regulated by the AUC, primarily under the provisions of the *Gas Utilities Act (Alberta)* and the *Pipeline Act (Alberta)*.

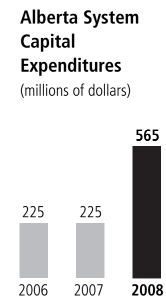
In December 2008, the AUC approved TCPL's 2008 - 2009 Revenue Requirement Settlement Application, as discussed further in the "Pipelines – Opportunities and Developments" section of this MD&A.

The Alberta System's net earnings of $145 million in 2008 were $7 million higher than in 2007. The increase was due to the recognition of earnings related to the revenue requirement settlement. Earnings in 2007 reflected an ROE of 8.51 per cent on deemed common equity of 35 per cent.

Net earnings of $138 million in 2007 were $2 million higher than in 2006. The increase was primarily due 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 Alberta Energy and Utilities Board, the AUC's predecessor, was 8.51 per cent in 2007 compared with 8.93 per cent in 2006 on deemed common equity of 35 per cent.







ANR

TCPL completed the acquisition of ANR in February 2007. The operations of ANR are regulated primarily by the U.S. Federal Energy Regulatory Commission (FERC). ANR provides natural gas transportation, storage and various capacity-related services to a variety of customers in both the U.S. and Canada. ANR's transmission system has a peak-day capacity of 6.8 billion cubic feet per day (Bcf/d). Due to the seasonal nature of its business, ANR's volumes and revenues are generally expected to be higher in the winter months. ANR also owns and operates 250 Bcf of underground natural gas storage facilities in Michigan. ANR's 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 Company's (ANR Pipeline) rates were established pursuant to a settlement approved by the FERC effective November 1997. ANR Storage Company's rates were established pursuant to a settlement approved by the FERC effective June 1990. None of ANR's FERC-regulated operations are required to file for new rates at any time in the future, nor are any of the operations prohibited from filing a rate case.

Net income for 2008 was $132 million compared to $104 million for the period from the date of acquisition on February 22, 2007 to December 31, 2007. The increase in 2008 was primarily due to a full year of earnings in 2008 and increased revenues from new growth projects, partially offset by higher OM&A costs, including remediation expenditures for damage caused by Hurricane Ike.

GTN

Both of GTN's systems, the GTN System and North Baja (collectively, GTN), are subject to FERC-approved tariffs that establish maximum and minimum rates for various services. GTN's pipeline rates were established pursuant to a settlement approved by the FERC in January 2008, and these rates became effective January 1, 2007. Under the settlement, a five-year moratorium was established during which the GTN System and the settling parties are prohibited under the *Natural Gas Act of 1938* from taking certain actions, including any filings to adjust rates. The settlement also requires the GTN System to file a rate case within seven years of the effective date. The systems are permitted to discount or negotiate these rates on a non-discriminatory basis. GTN's earnings are affected by variations in contracted volume levels, volumes delivered and prices charged under the various service types, as well as by variations in the costs of providing services.

GTN's comparable earnings were $65 million in 2008, an increase of $7 million compared to 2007 primarily due to decreased OM&A expenses. An increase in revenues for North Baja was offset by a decrease in revenues for the GTN System.

Comparable earnings were $58 million in 2007, a $12 million increase from 2006. The increase was primarily due to the positive impact of the rate case settlement in 2007, partially offset by lower long-term firm contracted volumes, a higher provision taken for non-payment of contract revenues from Calpine and a weaker U.S. dollar in 2007.

Other Pipelines

TCPL'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.

TCPL's comparable earnings from Other Pipelines were $96 million in 2008 compared to $87 million in 2007. The increase was primarily due to lower general, administrative and support costs, and higher earnings from PipeLines LP, Tamazunchale and Iroquois, partially offset by lower earnings from Gas Pacifico/INNERGY, TransGas, Portland and Great Lakes.

Comparable earnings from Other Pipelines were $87 million in 2007, a $6 million increase compared to 2006. The increase was primarily due to higher PipeLines LP earnings resulting from TCPL's increased ownership interests in PipeLines LP and Great Lakes, and a full year of earnings in 2007 from Tamazunchale. These increases were partially offset by higher project development and support costs associated with growing the Pipelines business, the effects of a weaker U.S. dollar in 2007 and proceeds of a bankruptcy settlement received by Portland in 2006.

At December 31, 2008, Other Assets included $74 million and $42 million for capitalized costs related to the Keystone expansion to the U.S. Gulf Coast and the Bison pipeline project, respectively.

PIPELINES – OPPORTUNITIES AND DEVELOPMENTS

Keystone

Keystone is expected to deliver crude oil from Hardisty, Alberta, to U.S. Midwest markets at Wood River and Patoka in Illinois, and to Cushing, Oklahoma.

In March 2008, the U.S. Department of State issued a Presidential Permit to Keystone authorizing construction, maintenance and operations of facilities at the U.S./Canada border for the transportation of crude oil between the two countries. Construction of Keystone began in May 2008 in both Canada and the U.S. Commissioning of the Wood River and Patoka segment is expected to commence in late 2009 with commercial operations to follow in early 2010. Commissioning of the Cushing segment is expected to commence in late 2010.

In June 2008, Keystone received approval from the NEB to add new pumping facilities to accommodate an increase to approximately 590,000 Bbl/d from 435,000 Bbl/d in volumes to be delivered to the Cushing markets.

After an open season conducted during third quarter 2008, Keystone secured additional firm, long-term contracts totaling 380,000 Bbl/d for an average term of approximately 17 years. With these shipper commitments, Keystone will proceed with the necessary regulatory applications in Canada and the U.S. for approvals to construct and operate an expansion of the pipeline system that will provide additional capacity from Western Canada to the U.S. Gulf Coast in 2012 and will increase the total commercial capacity of Keystone to approximately 1.1 million Bbl/d. With the additional contracts, Keystone now has secured long-term commitments for 910,000 Bbl/d for an average term of approximately 18 years. This includes commitments made by shippers to sign transportation service agreements for 35,000 Bbl/d capacity in an open season to be held in 2009. The commitments represent approximately 83 per cent of the commercial design of the system.

The entire Keystone project is currently expected to cost approximately US$12 billion between 2008 and 2012. In 2008, the Keystone partnerships made capital expenditures of approximately $1.7 billion on the entire project, of which $1.0 billion was contributed by TCPL.

TCPL has agreed to increase its equity ownership in the Keystone partnerships up to 79.99 per cent from 50 per cent with ConocoPhillips' equity ownership being reduced concurrently to 20.01 per cent. In accordance with this agreement, TCPL will fund 100 per cent of the construction expenditures until the participants' project capital contributions are aligned with the revised ownership interests. At December 31, 2008, TCPL's equity ownership in the Keystone partnerships was approximately 62 per cent. Certain parties that have made volume commitments to the Keystone expansion have an option to acquire up to a combined 15 per cent equity ownership in the Keystone partnerships by the end of first quarter 2009. If all of the options are exercised, TCPL's equity ownership would be reduced to 64.99 per cent.

Keystone's tolls, tariffs and facilities are regulated by the NEB in Canada and the FERC in the U.S., and have been approved for the segments shipping to Wood River, Patoka and Cushing. The Company expects the tolls and tariffs to remain in place for the term of the initial shipper contracts, which comprise approximately 83 per cent of Keystone's commercial capacity.

Canadian Mainline

In December 2008, the NEB announced that, pursuant to its formula, the 2009 allowed ROE for NEB-regulated pipelines, including the Canadian Mainline, will be 8.57 per cent, a decrease from 8.71 per cent in 2008.

Alberta System

In December 2008, the AUC approved the Alberta System's 2008 - 2009 Revenue Requirement Settlement Application. As part of the settlement, fixed costs were established for ROE, income taxes and OM&A costs. Any variances between actual costs and those agreed to in the settlement accrue to TCPL, subject to an ROE and income tax adjustment mechanism, which accounts for variances between actual and settlement rate base, and income tax assumptions. The other cost elements of the settlement are treated on a flow-through basis.

In November 2008, an NEB hearing concluded on TCPL's application to establish Federal jurisdiction over the Alberta System. A decision is expected from the NEB at the end of February 2009. Changing from AUC to NEB jurisdiction will allow the expansion of the Alberta System beyond Alberta provincial borders.

In October 2008, the AUC approved TCPL's application for a permit to construct the North Central Corridor expansion at a cost of approximately $925 million. The expansion comprises a 300 km (186 miles) natural gas pipeline and associated compression facilities on the northern section of the Alberta System.

On September 8, 2008, TCPL reached a proposed agreement with Canadian Utilities Limited (ATCO Pipelines) to provide seamless natural gas transmission service to customers. If approved by regulatory authorities, the arrangement will see the two companies combine physical assets under a single rates and services structure with a single commercial interface for customers but with each company separately managing assets within distinct operating territories in the province. TCPL continues to work with all stakeholders to finalize this agreement.

In February 2008, the AUC initiated a Generic Cost of Capital proceeding to review the generic ROE and capital structures of AUC regulated utilities. In November 2008, TCPL filed an application requesting an 11 per cent ROE on 40 per cent deemed common equity for the Alberta System in 2009. The hearing is scheduled to begin on May 19, 2009.

ANR

In 2008, ANR completed its STEP 2008 project, which added 14 Bcf of storage and 200 million cubic feet per day (mmcf/d) of withdrawal capacity to the Cold Springs 1 storage field located in Northern Michigan, and increased ANR's total storage capacity to 250 Bcf. The project was completed under budget and service was provided on schedule. Supply on ANR's southwest leg was increased as a result of an interconnect with the Rockies Express natural gas pipeline, which commenced service in January 2008. There is strong potential for new supply on the southeast leg from shale gas in the mid-continent region, and another interconnect with the Rockies Express pipeline is planned for the southeast leg in Indiana in mid-2009. ANR is also pursuing other supply additions on both its southwest and southeast legs.

In September 2008, certain portions of the Company's Gulf of Mexico offshore facilities were impacted by Hurricane Ike. The Company estimates its total exposure to damage costs to be approximately US$30 million to US$40 million, mainly to replace, repair and abandon capital assets, including the estimated cost to abandon an offshore platform. At December 31, 2008, capital expenditures of US$2 million and OM&A costs of US$6 million had been incurred. The remaining costs are primarily expected to be capital expenditures. Service on the majority of the offshore facilities has been restored and related throughput volumes have returned to near pre-hurricane levels. The timing of the remaining facilities' return to service is primarily dependent upon decisions to be made by upstream producers regarding their damaged facilities in the Gulf of Mexico.

Palomar

In December 2008, Palomar Gas Transmission LLC filed with the FERC for a certificate to build a pipeline extending from the GTN System in central Oregon, to the Columbia River northwest of Portland. The proposed pipeline is expected to be capable of transporting up to 1.3 Bcf/d of natural gas. The project is a 50/50 joint venture of GTN and Northwest Natural Gas Co.

North Baja

In September 2008, the FERC approved North Baja's application to build a natural gas pipeline to serve the Yucca Power Plant owned by Arizona Public Service Company. Three miles of the proposed pipeline are expected to be in the U.S. and owned by North Baja, and another three miles in Mexico are owned by Gasoducto Bajanorte. Pending final approval by the U.S. Government, construction is expected to commence in first quarter 2009 with a projected in-service date of May 2009.

Portland

On April 1, 2008, Portland filed a general rate case with the FERC proposing a rate increase of approximately six per cent as well as other changes to its tariffs. In accordance with a FERC order dated May 1, 2008, the proposed tariffs went into effect on September 1, 2008, subject to refund. The hearing is scheduled to begin on July 13, 2009.

TQM

In December 2008, the NEB concluded a proceeding with respect to TQM's Cost of Capital application for 2007 and 2008. The application sought an ROE of 11 per cent on deemed equity of 40 per cent. The proceeding also provided an opportunity for TQM to propose alternatives to the current ROE formula. A decision from the NEB is expected in first quarter 2009.

U.S. Rockies Pipeline Projects

The Bison pipeline project is a proposed pipeline from the Powder River Basin in Wyoming to the Northern Border system in North Dakota. The project has shipping commitments for approximately 405 mmcf/d and is expected to be in service in fourth quarter 2010. The capital cost of the Bison pipeline project is estimated at US$500 million to US$600 million. TCPL continues to work with Bison shippers to finalize the size and design of this project.

In addition, TCPL is proposing the Pathfinder pipeline project, a 1,006 km (625 miles) pipeline from Meeker, Colorado to the Northern Border system in North Dakota. A portion of the Pathfinder pipeline may share a common route with the Bison pipeline and may also share some common facilities. TCPL continues to work with prospective Pathfinder shippers to advance this project.

TCPL and Williams Gas Pipeline Company, LLC (Williams) are evaluating the development of the Sunstone pipeline, a proposed pipeline from Wyoming to Stanfield, Oregon. This project would provide Pacific Northwest and California markets with access to incremental Rockies supply. TCPL and its partner continue to work with customers to determine the appropriate size, time and route for this project.

Mackenzie Gas Pipeline Project

The MGP is a proposed 1,200 km (746 miles) 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.

TCPL's involvement with the MGP arises from a 2003 agreement between the Mackenzie Valley Aboriginal Pipeline Group (APG) and the MGP, whereby TCPL agreed to finance the APG's one-third share of the pre-development costs associated with the project. Cumulative advances made by TCPL totaled $140 million at December 31, 2008 and are included in Other Assets. These amounts constitute a loan to the APG, which becomes repayable only after the natural gas pipeline commences commercial operations. The total amount of the loan is expected to form part of the rate base of the pipeline and to subsequently be repaid from the APG's share of future natural gas pipeline revenues or from alternate financing. If the project does not proceed, TCPL has no recourse against the APG for recovery of advances made. Accordingly, TCPL's ability to recover its investment through loan repayments and/or equity ownership in the project depends upon a successful outcome of the project.

Under the terms of certain MGP agreements, TCPL 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 it. In addition, TCPL 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.

TCPL and the other co-venture companies involved in the MGP continue to pursue approval of the proposed project, focusing on obtaining regulatory approval and the Canadian government's support of an acceptable fiscal framework. Project timing continues to be uncertain. Detailed discussions with the Canadian government have taken place and have resulted in a proposal in January 2009 from the government to the MGP. The co-venture group is considering the proposal and is expected to respond to the government in the near future. In the event the co-venture group is unable to reach an agreement with the government on an acceptable fiscal framework, the parties will need to determine the appropriate next steps for the project. For TCPL, this may result in a reassessment of the carrying amount of the APG advances.

Alaska Pipeline Project

In November 2007, TCPL submitted an application to the State of Alaska for a license to construct the Alaska Pipeline Project under the AGIA. In January 2008, Alaska Governor Sarah Palin's administration determined that TCPL's application was the only proposal that met all of the state's requirements and in December 2008 the State of Alaska issued the AGIA license to TCPL. Under the AGIA, the State of Alaska has agreed to reimburse a share of TCPL's eligible pre-construction costs to a maximum of US$500 million.

The Alaska Pipeline Project will be a 4.5 Bcf/d natural gas pipeline extending approximately 2,760 km (1,715 miles) from a new natural gas treatment plant at Prudhoe Bay, Alaska to Alberta. This pipeline will integrate with the Alberta System to provide access to diverse markets across North America. The application included provision for expansions up to 5.9 Bcf/d through the addition of compressor stations in Alaska and Canada. TCPL estimated the total capital cost of the entire project to be approximately US$26 billion in 2007 dollars.

Since the AGIA license was awarded, TCPL has moved forward with developing the project, which involves engineering, environmental, aboriginal relations and commercial work to conclude an initial binding open season by mid-2010. TCPL continues its efforts to align with potential shippers and if sufficient firm contracts are secured in the open season, construction would begin following regulatory approvals, with an anticipated in-service date of 2018.

PIPELINES – BUSINESS RISKS

Supply, Markets and Competition

TCPL 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 TCPL's pipelines. In addition, the continued expiration of long-term firm contracts has resulted in significant reductions in long-term firm contracted capacity and shifts to short-term firm and interruptible contracts on the Canadian Mainline, the Alberta System, Foothills and the GTN System.

In 2008, the gas supply environment changed. Production out of the WCSB declined while supply in the U.S. grew. Previously it had been expected that U.S. supply would decline. Furthermore, with lower natural gas prices, lower cost U.S. gas developments may hinder the further development of WCSB gas supplies.

TCPL's primary source of natural gas supply is the WCSB. The WCSB has 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, supply from the WCSB has declined in recent years due to a continued reduction in levels of drilling activity in the basin. The reduced drilling activity is a result of lower prices, higher supply costs, which include higher royalties in Alberta, and competition for capital from other North American basins that have lower exploration costs. Drilling levels in the WCSB are expected to reach a low point in 2009 and then should begin to recover in the ensuing years assuming that gas prices stabilize at $6 to $7 per gigajoule (GJ) and that finding and development costs become more economical. TCPL anticipates there will be excess natural gas pipeline capacity out of the WCSB in the foreseeable future as a result of capacity expansions 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 within Alberta driven by oil sands and electricity generation requirements.

TCPL'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. Recently, shale gas production in B.C. has emerged as a potentially significant natural gas supply source.

Historically, TCPL'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, resulting in an increase in Canadian Mainline tolls.

Demand for natural gas in TCPL'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. However, the Company believes the current environment could reverse this trend in the short term given sufficient levels of erosion of market demand. Although there are opportunities to increase market share in Canadian domestic and U.S. export markets, TCPL 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 TCPL are now capable of receiving supplies from new natural gas pipelines that source U.S. and Atlantic Canadian supplies.

The source of oil supply for Keystone is located primarily in Alberta, which produces approximately 79 per cent of the oil in the WCSB. In 2008, the WCSB produced a total of approximately 2.4 million Bbl/d, comprised of 1.2 million Bbl/d of conventional crude oil and condensate, and 1.2 million Bbl/d of oil from the oil sands area of Alberta. The production of conventional oil has been declining but has been offset by increases in production of oil from the Alberta oil sands. The Alberta Energy Resources Conservation Board has estimated that there are 173 billion barrels of remaining established reserves in the Alberta oil sands.

A decline in oil prices in late 2008 has resulted in announcements of delays in oil sands projects and upgraders, however, in December 2008, the Canadian Association of Petroleum Producers forecast WCSB oil supply would increase from 2.4 million Bbl/d in 2008 to 3.5 million Bbl/d by 2015 and 4.1 million Bbl/d by 2020.

Keystone has 910,000 Bbl/d of contracts for capacity, on a ship or pay basis, with an average contract life of 18 years, which the Company believes will provide incentive for contract shippers to ship on Keystone. However, Keystone must compete for spot throughput with other oil pipelines from Alberta.

Keystone's markets for crude oil are refiners in the U.S. Midwest and Gulf Coast regions. A competing pipeline can also deliver WCSB crude oil to the Midwest markets supplied by Keystone. Currently, competing pipelines can deliver oil to the U.S. Gulf Coast, through interconnections with other pipelines. Keystone must also compete with U.S. domestically produced oil and imported oil for markets in the Midwest and Gulf Coast regions.

ANR's natural gas supply is primarily sourced from the Gulf of Mexico and mid-continent U.S. regions, which are also served by competing natural gas pipelines. ANR also has competition from other natural gas pipelines and storage operations 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 shale production in the mid-continent, from the Rockies Express natural gas pipeline originating in the Rocky Mountain region, and from LNG. 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. In addition to pipeline competition for market and supply, current difficult economic conditions are expected to reduce energy demand and may put future ANR capacity renewals at risk as the North American economy slows or potentially contracts in key markets in the upper U.S. Midwest. As lower natural gas prices reduce drilling activity, the supply growth that has been fuelling the growth in pipeline infrastructure in the mid-continent could slow down but is still expected to exceed demand requirements in the near term. These factors could negatively affect pipeline capacity value as transportation capacity becomes more abundant.

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 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 has experienced significant contract non-renewals since 2005 as the natural gas it transports from the WCSB competes for the California and Nevada markets against supplies from the Rocky Mountain and southwestern U.S. basins. Recently, Pacific Gas and Electric Company, the GTN System's largest customer, received California Public Utilities Commission approval to commit to capacity on a proposed competing project out of the Rocky Mountain basin to the California border.

Regulatory Financial Risk

Regulatory decisions continue to have a significant impact on the financial returns from existing investments in TCPL's Canadian wholly owned pipelines and are expected to have a similarly significant impact on financial returns from future investments. TCPL remains concerned that current financial returns approved by regulators are not as competitive as returns from other assets with similar risk profiles. In recent years, TCPL applied to the NEB and the AUC for an ROE of 11 per cent on 40 per cent deemed common equity for both the Canadian Mainline and the Alberta System. The NEB has reaffirmed its ROE formula and the AUC has established a generic ROE that is largely aligned with the NEB formula. Through rate applications and negotiated settlements, TCPL has been able to improve the common equity components of its Canadian wholly owned pipeline capital structures, but there is no assurance that this success can be repeated.

Most recently, TCPL has continued to address concerns about financial returns on the Alberta System in the AUC's 2009 Generic Cost of Capital Proceeding. In November 2008, TCPL filed an application requesting an ROE of 11 per cent on 40 per cent deemed common equity for the Alberta System. 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 these proceedings may influence the regulators' view of fair financial returns on equity associated with TCPL's other Canadian wholly owned pipelines.

Throughput Risk

As transportation contracts expire, TCPL's U.S. natural gas pipelines are expected to become 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

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

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

PIPELINES – OUTLOOK

TCPL assumes that its operations in 2009 will be materially consistent with those in 2008 except for the impact of those factors discussed in this section.

Although demand for natural gas and crude oil has declined and is expected to further decline in North America in 2009 due to the current economic downturn, the Company expects demand to increase in the long term. TCPL'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 shale gas, coalbed methane and LNG, and construction and expansion of Keystone.

TCPL expects producers will continue to explore and develop new fields in Western Canada, particularly in northeastern B.C. and the west and central foothills regions of Alberta. There is also expected to be significant exploration and development activity aimed at unconventional resources such as coalbed methane and shale gas.

In 2008, TCPL filed an application with the NEB to establish federal jurisdiction for the Alberta System. If the application is approved, the Alberta System will switch from AUC regulation to NEB regulation, allowing it to construct and operate pipeline extensions into other provinces and allowing it to provide direct integrated Alberta System natural gas transmission service to gas production locations outside of Alberta. Extensions of the Alberta System beyond Alberta's borders are currently prohibited under provincial regulation. An NEB jurisdiction decision is expected in first quarter 2009.

Most of TCPL's current expansion plans in Canadian natural gas transmission are focused on the Alberta System. TCPL recently concluded a binding open season process for natural gas transmission service for the Montney shale gas region located in northeastern B.C. Five shippers have committed to firm gas transportation contracts on the Groundbirch pipeline that will serve the Montney region. Volumes associated with these commitments will reach 1.1 Bcf/d by 2014. The Groundbirch pipeline is expected to commence service in fourth quarter 2010, subject to receipt of necessary approvals.

In addition, TCPL is finalizing details associated with a binding open season and pipeline extension project to service the Horn River shale gas region located in northeastern B.C. Five shippers have committed to firm gas transportation contracts for a total volume of 378 mmcf/d by second quarter 2012. Subject to concluding a successful binding open season, the Horn River project is expected to commence operation in second quarter 2011, subject to receipt of necessary approvals.

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

In addition to extensions into B.C., new facilities are required to expand the integrated Alberta System in response to changes in the distribution of supply and in markets across the Alberta System.

In the U.S., TCPL expects unconventional production will continue to be developed from shale gas reservoirs in east Texas, northwest Louisiana, Arkansas, and southwest Oklahoma. Supplies from coalbed methane and tight gas sands in the Rocky Mountain region are also expected to grow. Additionally, in the medium to long term, some level of incremental supply is anticipated from LNG imports into the U.S., particularly in the summer months. The resulting growth in supply will provide additional commercial opportunities for TCPL. 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 the additional Rocky Mountain and shale gas production to midwestern and eastern U.S. markets, including interconnections with ANR. As mid-continent supplies develop, the southeast leg of ANR has capacity to transport additional volumes of Rocky Mountain and mid-continent shale production, as well as LNG.

Producers continue to develop new oil supply in Western Canada. There are several new oil sands projects under construction that will begin production in 2009 and 2010. By 2015, oil sands production is expected to double from 1.2 million Bbl/d in 2008 and total Western Canada oil supply is projected to grow over the same period to approximately 3.5 million Bbl/d from 2.4 million Bbl/d. The primary market for new oil production extends from the U.S. Midwest to the U.S. Gulf Coast and contains a large number of refineries that are well equipped to handle Canadian light and heavy crude oil blends. Incremental western Canadian crude oil production is expected to replace declining U.S. imports of crude oil from other countries.

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

TCPL 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 also 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. 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 firm transportation contract volumes due to customer defaults, lower supply available for export from the WCSB and expiry of long-term contracts could have a negative impact on short-term earnings from TCPL'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 TCPL's U.S. pipelines. Earnings from Pipelines' foreign operations are also impacted by changes in foreign currency exchange rates.

Capital Expenditures

Total capital spending for all pipelines in 2008 was $1.8 billion. Capital spending for the wholly owned pipelines in 2009 is expected to be approximately $1.1 billion. In addition, capital spending for TCPL's share of constructing Keystone is expected to be approximately $3.6 billion in 2009.

NATURAL GAS THROUGHPUT VOLUMES
(Bcf)

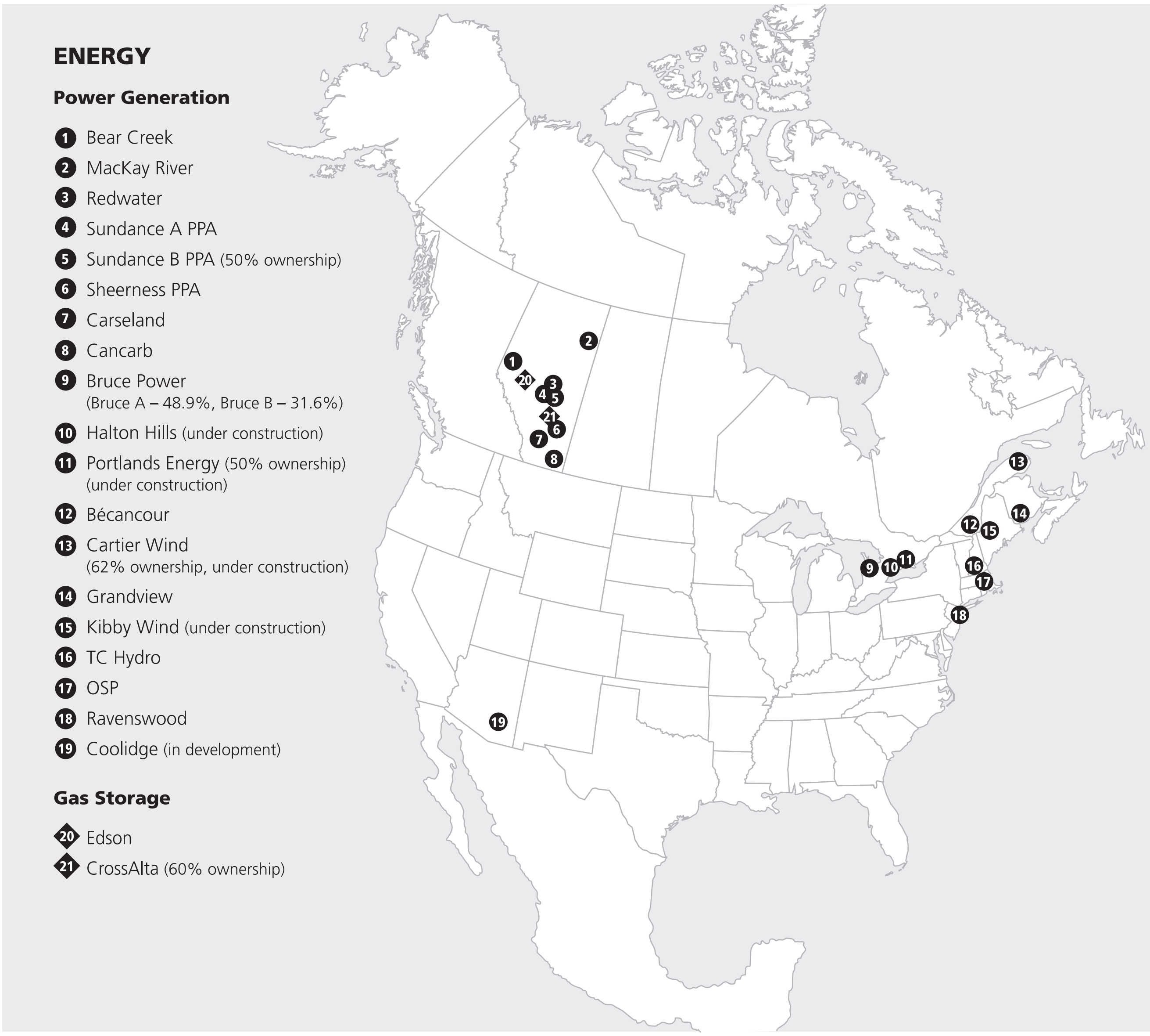
	2008	2007	2006
Canadian Mainline(1)	**3,467**	3,183	2,955
Alberta System(2)	**3,800**	4,020	4,051
ANR(3)	**1,655**	1,210	n/a
GTN System	**783**	827	790
Foothills	**1,292**	1,441	1,403
North Baja	**104**	90	95
Great Lakes	**784**	829	816
Northern Border	**731**	800	799
Iroquois	**376**	394	384
TQM	**170**	207	158
Ventures LP	**165**	178	179
Gas Pacifico	**73**	71	52
Portland	**50**	58	52
Tamazunchale(4)	**53**	29	n/a
Tuscarora	**30**	28	28
TransGas	**26**	24	22

(1) Canadian Mainline physical receipts originating at the Alberta border and in Saskatchewan in 2008 were 1,898 Bcf (2007 – 2,090 Bcf; 2006 – 2,207 Bcf).

(2) Field receipt volumes for the Alberta System in 2008 were 3,843 Bcf (2007 – 4,047 Bcf; 2006 – 4,160 Bcf).

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

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

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

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 TCPL's adjacent thermal carbon black (a natural gas by-product) facility, Cancarb is located in Medicine Hat, Alberta.

BRUCE POWER Bruce Power is a nuclear generating facility located northwest of Toronto, Ontario. TCPL owns 48.9 per cent of Bruce A, which has four 750 MW reactors, two of which are currently being refurbished and are expected to restart in 2010. TCPL owns 31.6 per cent of Bruce B, which has four operating reactors with a combined capacity of approximately 3,200 MW.

HALTON HILLS A 683 MW natural gas-fired power plant, 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 the downtown area of Toronto, Ontario. The plant is 50 per cent owned by TCPL and is expected to be commissioned in its combined-cycle mode in first quarter 2009.

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

CARTIER WIND The 740 MW Cartier Wind farm consists of six wind power projects located in Québec. Cartier Wind is 62 per cent owned by TCPL. Three of the projects, Baie-des-Sables, Anse-á-Valleau and Carleton have generating capacities of 110 MW, 101 MW and 109 MW, respectively. 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.

KIBBY WIND The 132 MW Kibby Wind power project is under construction and will include 44 turbines located in Kibby and Skinner Townships in Maine. Construction began in July 2008 and commissioning of the first phase is expected to begin in fourth quarter 2009.

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 Burrillville, Rhode Island.

RAVENSWOOD In August 2008, TCPL acquired the 2,480 MW multiple unit generating facility in Queens, New York employing dual-fuel capable steam turbine, combined cycle and combustion turbine technology.

COOLIDGE A 575 MW simple-cycle, natural gas-fired peaking power generation station, Coolidge is under development in Coolidge, Arizona. Detailed engineering, geotechnical and regulatory work began in 2008 and commissioning of the facility is expected in 2011.

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. TCPL owns 60 per cent of CrossAlta, which has a working natural gas capacity of 54 Bcf with a maximum capability of delivering 480 mmcf/d.

ENERGY – HIGHLIGHTS

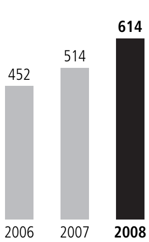
- Energy's net earnings were $614 million in 2008, an increase of $100 million from $514 million in 2007. Energy's comparable earnings were $641 million in 2008, an increase of $182 million from $459 million in 2007.
- In August 2008, TCPL acquired the 2,480 MW Ravenswood facility in Queens, New York for US$2.9 billion, subject to certain post-closing adjustments.
- Approximately 2,700 MW of additional generation capacity was under construction at December 31, 2008, with an anticipated capital cost of $5 billion.
- Since 1999, the nominal generating capacity of TCPL's Energy business has increased by approximately 7,800 MW, representing an investment of approximately $7 billion to the end of 2008, with an additional 2,700 MW currently under development and construction.

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

	2008	2007	2006
Western Power	**426**	308	297
Eastern Power	**338**	255	187
Bruce Power	**201**	167	235
Natural Gas Storage	**135**	136	93
General, administrative, support costs and other	**(168)**	(158)	(144)
Operating income	**932**	708	668
Financial charges	**(23)**	(22)	(23)
Interest income and other	**6**	10	5
Income taxes	**(274)**	(237)	(221)
Comparable Earnings[1]	**641**	459	429
Writedown of Broadwater costs	**(27)**	–	–
Gain on sale of land	**–**	14	–
Fair value adjustments of natural gas storage inventory and forward contracts	**–**	7	–
Income tax adjustments	**–**	34	23
Net Earnings	**614**	514	452

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

Energy Net Earnings
(millions of dollars)



Energy's net earnings in 2008 of $614 million increased $100 million compared to $514 million in 2007. Comparable earnings of $641 million in 2008 increased $182 million compared to 2007 and excluded a $27 million writedown of costs previously capitalized for Broadwater. The increases in comparable and net earnings were due to higher operating income in Western Power, Eastern Power and Bruce Power. Comparable earnings of $459 million for 2007 excluded net unrealized gains of $7 million resulting from changes in fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts, a $14 million gain on sale of land and $34 million of favourable income tax adjustments.

Energy's net earnings in 2007 were $514 million compared to $452 million in 2006. Comparable earnings were $459 million in 2007, an increase of $30 million from 2006. The increase was due to higher operating income in Eastern Power, Natural Gas Storage and Western Power, partially offset by a reduced contribution from Bruce Power. Comparable earnings excluded net unrealized gains of $7 million resulting from natural gas storage fair value changes, a $14 million gain on sale of land, $34 million of favourable income tax adjustments in 2007 as well as a $23 million favourable impact in 2006 from future income taxes as a result of reductions in Canadian federal and provincial corporate income tax rates.

POWER PLANTS – NOMINAL GENERATING CAPACITY AND FUEL TYPE

	MW	Fuel Type
Western Power		
Sheerness	756	Coal
Coolidge(1)	575	Natural gas
Sundance A	560	Coal
Sundance B(2)	353	Coal
MacKay River	165	Natural gas
Carseland	80	Natural gas
Bear Creek	80	Natural gas
Redwater	40	Natural gas
Cancarb	27	Natural gas
	2,636	
Eastern Power		
Ravenswood(3)	2,480	Natural gas/oil
Halton Hills(1)	683	Natural gas
TC Hydro	583	Hydro
OSP	560	Natural gas
Bécancour	550	Natural gas
Cartier Wind(4)	458	Wind
Portlands Energy(5)	275	Natural gas
Kibby Wind(1)	132	Wind
Grandview	90	Natural gas
	5,811	
Bruce Power(6)	2,480	Nuclear
Total nominal generating capacity(1)	10,927	

(1) Halton Hills and Kibby Wind are currently under construction. Coolidge is currently under development.

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

(3) Acquired in third quarter 2008.

(4) Represents TCPL's 62 per cent share of the total 740 MW project. Three of six wind farms were placed in service, one in November 2008, one in November 2007 and the other in November 2006, with a combined generating capacity of 320 MW.

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

(6) Represents TCPL's 48.9 per cent proportionate interest in Bruce A and 31.6 per cent proportionate interest in Bruce B.

ENERGY – FINANCIAL ANALYSIS

Western Power

As at December 31, 2008, Western Power owns or has the rights to approximately 2,600 MW of power supply in Alberta and the western U.S. from its three long-term power purchase arrangements (PPA), six natural gas-fired cogeneration facilities and a peaking facility under development in Arizona. The power supply portfolio of Western Power in Alberta comprises approximately 1,700 MW of low-cost, base-load coal-fired generation supply through the three long-term PPAs and approximately 400 MW of natural gas-fired cogeneration assets. This supply portfolio includes some of the lowest cost, most competitive generation in the Alberta market area. The Sheerness and Sundance B PPAs have remaining terms of 12 years, while the Sundance A PPA has a remaining term of nine years. In 2008, the Salt River Project Agricultural Improvement and Power District (Salt River Project), a utility based in Phoenix, Arizona, entered into a 20-year PPA to secure 100 per cent of the output from TCPL's planned Coolidge generating station. The simple-cycle natural gas-fired peaking power facility to be located in Coolidge, Arizona is expected to be commissioned in 2011 and have a nominal generating capacity of 575 MW.

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 natural 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 Energy's 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 TCPL would otherwise have to purchase electricity in the open market to fulfil its contractual sales obligations. To reduce exposure to spot market prices on uncontracted volumes, Western Power had, as at December 31, 2008, fixed-price power sales contracts to sell approximately 8,800 gigawatt hours (GWh) in 2009 and 5,500 GWh in 2010.

Plant operations in Alberta consist of five natural gas-fired cogeneration power plants 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 natural 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 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 an increase in the market heat rate and declines in proportion to a decrease in the market heat rate. Market heat rates in Alberta increased in 2008 by approximately six per cent as a result of an increase in average power prices, partially offset by an increase in spot market natural gas prices. Market heat rates averaged approximately 12.05 GJ/MWh in 2008 compared to approximately 11.40 GJ/MWh in 2007.

Western Power's plants operated with an average plant availability of approximately 87 per cent in 2008 compared to 90 per cent in 2007. The decrease was primarily due to an extended outage at the Cancarb power plant.

Western Power Results
Year ended December 31 *(millions of dollars)*

	2008	2007	2006
Revenues			
Power	**1,140**	1,045	1,185
Other[1]	**130**	89	169
	1,270	1,134	1,354
Commodity purchases resold			
Power	**(575)**	(608)	(767)
Other[2]	**(64)**	(65)	(135)
	(639)	(673)	(902)
Plant operating costs and other	**(180)**	(135)	(135)
Depreciation	**(25)**	(18)	(20)
Operating income	**426**	308	297

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

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

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

	2008	2007	2006
Supply			
Generation	**2,322**	2,154	2,259
Purchased			
Sundance A & B and Sheerness PPAs	**12,368**	12,199	12,712
Other purchases	**807**	1,433	1,905
	15,497	15,786	16,876
Contracted vs. Spot			
Contracted	**11,284**	11,998	12,750
Spot	**4,213**	3,788	4,126
	15,497	15,786	16,876

Operating income was $426 million in 2008, an increase of $118 million from $308 million in 2007. The increase was primarily due to increased margins from a combination of higher overall realized power prices and market heat rates on uncontracted volumes of power sold, as well as a $23 million increase from sales of sulphur at significantly higher prices in 2008. In 2008, the Company sold the remainder of its sulphur stock pile, which it has been selling in modest quantities on a break-even basis since 2005.

Revenues increased in 2008 primarily due to the higher overall power sales prices. Commodity purchases resold decreased in 2008 compared to 2007 primarily due to a decrease in volumes purchased and the expiry of certain retail contracts. Plant operating costs and other, which includes fuel gas consumed in generation, increased in 2008 as a result of higher volumes of gas purchased at higher prices. Purchased power volumes in 2008 decreased primarily due to the expiry of certain retail contracts, partially offset by increased utilization from the Alberta PPAs. Approximately 27 per cent of power sales volumes were sold in the spot market in 2008 compared to 24 per cent in 2007.

Operating income was $308 million in 2007, an increase of $11 million from $297 million in 2006. The increase was primarily due 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 primarily due 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 into the spot market in 2007, which was consistent with 2006.

Eastern Power

Eastern Power owns approximately 5,800 MW of power generation capacity, including facilities under construction or in the development phase. Eastern Power's current operating power generation assets are Ravenswood, TC Hydro, OSP, Bécancour, the Cartier Wind farms and Grandview. Ravenswood, acquired in August 2008, is a 2,480 MW gas and oil-fired generating facility consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology. Ravenswood, located in Queens, has the capacity to serve approximately 21 per cent of the overall peak load in New York City. The TC Hydro assets include 13 hydroelectric stations housing a total of 39 hydroelectric generating units in New Hampshire, Vermont and Massachusetts.

OSP, a natural gas-fired combined-cycle facility, is the largest power plant in Rhode Island. Bécancour, a natural gas-fired cogeneration plant located near Trois Rivières, Québec, was placed into service in September 2006. The entire power output is supplied to Hydro-Québec under a 20 year power purchase contract. Steam from this facility is sold to an industrial customer for use in commercial processes. Cartier has a combined generating capacity of 320 MW and consists of three wind farms, Carleton, Anse-á-Valleau, and Baie-des-Sables, which were placed into service in November 2008, November 2007 and November 2006, respectively. Output from these three wind farms is supplied to Hydro-Québec under 20 year power purchase contracts. Grandview is a natural gas-fired cogeneration facility on the site of the Irving Oil Refinery (Irving) in Saint John, New Brunswick. Under a 20 year tolling arrangement which will expire in 2025, Irving supplies fuel for the plant and contracts for 100 per cent of the plant's heat and electricity output.

Eastern Power conducts its business primarily in the deregulated New England and New York power markets and in Eastern Canada. In the New England market, TCPL has established a marketing operation through its wholly owned subsidiary, TransCanada Power Marketing Ltd. (TCPM). TCPM is located in Westborough, Massachusetts, and effective January 1, 2009, also markets the output from the Ravenswood facility. To reduce exposure to spot market prices on uncontracted volumes, Eastern Power had, as at December 31, 2008, fixed price sales contracts to sell forward approximately 13,000 GWh in 2009 and 15,000 GWh in 2010, although certain contracted volumes are dependant on customer usage levels. Actual amounts contracted in future periods will depend on market liquidity and other factors. Fixed price sales contracts in 2009 exclude approximately 4,300 GWh of generation from the Bécancour power plant as a result of a suspension of electricity generation that began in January 2008 and continues through December 2009. The suspension of the Bécancour power facility is discussed further in the "Energy – Opportunities and Developments" section of this MD&A.

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 2008, TCPM continued to expand its marketing presence and customer base in the New England market.

The Forward Capacity Market (FCM) in the New England power pool is intended to promote investment in new and existing power resources needed to meet growing consumer demand and maintain a reliable power system. Under the FCM, Independent System Operator New England (ISO-NE) projects the needs of the power system three years in advance, following which it holds an annual auction to purchase power resources to satisfy future needs. Prior to the auction period, certain transition payments are made to capacity suppliers in New England that were in existence at June 2006.

ISO-NE has undertaken two Forward Capacity Auctions (FCA) under the FCM framework for procurement of installed capacity; FCA1 for the 2010-2011 period and FCA2 for the 2011-2012 period. All of Eastern Power's existing and planned power assets in the New England market were entered into both FCA1 and FCA2. Both auctions resulted in significant amounts of qualifying capacity resulting in decreased prices. The clearing prices in these auctions were US$4.25 and US$3.12 per kilowatt-month, respectively. Future auction results will be affected by actual demand growth and the pace of progress in the development of new qualifying resources that bid into these auctions, as well as other factors.

The New York Independent System Operator (NYISO) relies on a locational capacity market intended to promote investment in new and existing power resources needed to meet growing consumer demand and maintain a reliable power system. Currently, a series of voluntary forward auctions and a mandatory spot demand curve price setting process is used to determine the price that is paid to capacity suppliers. There are separate demand curves for each of the three capacity zones: Long Island, New York City and the rest of the state. Ravenswood's capacity is located in the New York City capacity zone. Energy and capacity prices for Ravenswood are affected by circumstances that have an impact on supply and demand within this zone, certain NYISO market rules impacting both buyers and suppliers of capacity in this zone, and certain reliability criteria set out by the NYISO and the New York State Reliability Council. There is currently surplus capacity within this zone, however, TCPL expects capacity will tighten after 2009 as a result of the expected retirement of a power station owned by the New York Power Authority.

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

	2008	2007	2006
Revenues			
Power	**1,254**	1,481	789
Other[(2)]	**350**	239	292
	1,604	1,720	1,081
Commodity purchases resold			
Power	**(519)**	(755)	(379)
Other[(3)]	**(324)**	(208)	(257)
	(843)	(963)	(636)
Plant operating costs and other	**(342)**	(454)	(226)
Depreciation	**(81)**	(48)	(32)
Operating income	**338**	255	187

(1) Includes Carleton, Ravenswood, Anse-à-Valleau, Baie-des-Sables and Bécancour effective November 2008, August 2008, November 2007, November 2006 and September 2006, respectively.

(2) Other revenue includes sales of natural gas.

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

Eastern Power Sales Volumes[1] Year ended December 31 *(GWh)*	**2008**	2007	2006
Supply			
Generation	**5,043**	8,095	4,700
Purchased	**6,183**	6,986	3,091
	11,226	15,081	7,791
Contracted vs. Spot			
Contracted	**10,990**	14,505	7,374
Spot	**236**	576	417
	11,226	15,081	7,791

(1) Includes Carleton, Ravenswood, Anse-à-Valleau and Baie-des-Sables effective November 2008, August 2008, November 2007 and November 2006, respectively. Bécancour is included in Eastern Power effective September 2006 through December 2007.

Operating income was $338 million in 2008, $83 million higher than the $255 million earned in 2007. The increase was primarily due to increased water flows from the TC Hydro generation assets and higher realized prices on sales to commercial and industrial customers in New England, incremental income from the first full year of operations from the Anse-à-Valleau wind farm and the start-up of the Carleton wind farm in November 2008. On December 31, 2008, Ravenswood fulfilled its obligation under a tolling agreement with Hess Corporation that was in place at the time of acquisition. In 2009, TCPM will manage the marketing output of the Ravenswood plant in a manner consistent with its other U.S. northeast portfolio of assets. The agreement to temporarily suspend generation at the Bécancour facility beginning January 2008 resulted in decreases to power revenues, plant operating costs and other, generation volumes and contracted sales in 2008. The temporary suspension agreement has not materially affected Eastern Power's operating income due to capacity payments received pursuant to the agreement with Hydro-Québec. The agreement to suspend generation at the Bécancour facility was extended for one year to December 31, 2009.

Eastern Power's power revenues were $1,254 million in 2008, a decrease of $227 million from $1,481 million in 2007. This was primarily due to the temporary suspension of generation at the Bécancour facility and decreased sales to commercial and industrial customers in the New England market, partially offset by higher realized prices in New England, increased water flows through the TC Hydro generation assets, and incremental revenue from Ravenswood. Other revenue and other commodity purchases resold increased year-over-year as a result of an increase in the quantity of natural gas purchased and resold under OSP's and TCPM's natural gas supply contracts. Power commodity purchases resold and purchased power volumes were lower in 2008 due to the impact of decreased sales volumes to commercial and industrial customers, lower overall cost per GWh on purchased power volumes and increased power generation from the TC Hydro assets, 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 lower in 2008 primarily due to the temporary suspension of generation at the Bécancour facility, partially offset by incremental operating costs from Ravenswood.

Operating income was $255 million in 2007, $68 million higher than the $187 million earned in 2006. The increase was primarily due to incremental income from the first full year of operations from the Bécancour facility and the Baie-des-Sables wind farm, as well as 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.

Bruce Power

As at December 31, 2008, TCPL and BPC Generation Infrastructure Trust (BPC), a trust established by the Ontario Municipal Employees Retirement System, each owned a 48.9 per cent interest in Bruce A (2007 – 48.7 per cent). The remaining 2.2 per cent interest in Bruce A is owned by the Power Workers' Union Trust, the Society of Energy Professionals Trust and Bruce Power Employee Investment Trust. The Bruce A partnership subleases Bruce A Units 1 to 4 from the Bruce B partnership. TCPL continues to own 31.6 per cent of Bruce B, which consists of Units 5 to 8 and the supporting site infrastructure.

The following Bruce Power financial results reflect the operations of six of the eight Bruce Power units:

Bruce Power Results Year ended December 31 *(millions of dollars)*	**2008**	2007	2006
Bruce Power (100 per cent basis)			
Revenues			
Power	**2,064**	1,920	1,861
Other[1]	**96**	113	71
	2,160	2,033	1,932
Operating expenses			
Operations and maintenance[2]	**(1,066)**	(1,051)	(912)
Fuel	**(139)**	(104)	(96)
Supplemental rent[2]	**(174)**	(170)	(170)
Depreciation and amortization	**(151)**	(151)	(134)
	(1,530)	(1,476)	(1,312)
	630	557	620
TCPL's proportionate share:			
Bruce A (48.9%)	**62**	24	91
Bruce B (31.6%)	**158**	161	137
	220	185	228
Adjustments	**(19)**	(18)	7
TCPL's operating income from Bruce Power	**201**	167	235
Bruce Power – Other Information			
Plant availability			
Bruce A	**82%**	78%	81%
Bruce B	**87%**	89%	91%
Combined Bruce Power	**86%**	86%	88%
Planned outage days			
Bruce A	**91**	121	81
Bruce B	**100**	93	65
Unplanned outage days			
Bruce A	**27**	17	37
Bruce B	**65**	32	31
Sales volumes (GWh)			
Bruce A – 100 per cent	**10,580**	10,180	10,650
Bruce A – TCPL's proportionate share	**5,159**	4,959	5,158
Bruce B – 100 per cent	**24,680**	25,290	25,820
Bruce B – TCPL's proportionate share	**7,799**	7,992	8,159
Combined Bruce Power – 100 per cent	**35,260**	35,470	36,470
TCPL's proportionate share	**12,958**	12,951	13,317
Results per MWh			
Bruce A power revenues	**$62**	$59	$58
Bruce B power revenues	**$57**	$52	$48
Combined Bruce Power revenues	**$59**	$55	$51
Combined Bruce Power fuel	**$4**	$3	$3
Combined Bruce Power total operating expenses[3]	**$42**	$41	$35
Percentage of output sold to spot market	**23%**	45%	35%

(1) Other revenue includes Bruce A fuel cost recoveries of $61 million in 2008 (2007 – $35 million; 2006 – $30 million). Other revenue also includes unrealized losses of $6 million as a result of changes in fair value of held-for-trading derivatives in 2008 (2007 – $47 million gain; 2006 – nil).

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

(3) Net of fuel cost recoveries.

TCPL's operating income from Bruce Power was $201 million in 2008 compared to $167 million in 2007. TCPL's proportionate share of operating income in Bruce A increased $38 million to $62 million in 2008 compared to 2007 primarily due to higher realized prices and higher volumes associated with a decrease in outage days in 2008. TCPL's proportionate share of operating income in Bruce B decreased $3 million to $158 million in 2008 compared to 2007 primarily due to higher operating costs and lower volumes associated with an increase in outage days in 2008, and unrealized gains in 2007 from changes in the fair value of power swaps and forwards. Partially offsetting these decreases were higher realized prices reflecting a higher proportion of volumes sold at higher contract prices.

Combined Bruce Power prices, which are based solely on power revenues, were $59 per MWh in 2008 compared to $55 per MWh in 2007, 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 $42 per MWh in 2008 from $41 per MWh in 2007 primarily due to higher operating costs in 2008.

The Bruce units ran at a combined average availability of 86 per cent in 2008, which was consistent with the average availability in 2007.

TCPL's operating income from its combined investment in Bruce Power was $167 million in 2007 compared to $235 million in 2006. The decrease of $68 million was primarily due to lower output and higher operating costs associated with an increase in planned outage days, partially offset by higher overall realized prices.

Adjustments to TCPL's interest in Bruce Power's income before income taxes were lower in 2008 and 2007 than in 2006 primarily due to lower positive purchase price amortizations related to the expiry of power sales agreements.

The overall plant availability percentage in 2009 is expected to be in the low 90s for the four Bruce B units and the mid-80s for the two operating Bruce A units. An approximate six week maintenance outage of Bruce B Unit 8 is scheduled to begin in mid-April 2009 and an approximate six week maintenance outage of Bruce B Unit 6 is scheduled to begin in early October 2009. An approximate six week maintenance outage of Bruce A Unit 4 is scheduled to start in early March 2009 and an approximate one-month outage of Bruce A Unit 3 is expected to commence in mid-March 2009.

Bruce A

Income from Bruce A is affected by overall plant availability, which in turn is affected by planned and unplanned maintenance. As a result of a contract with the Ontario Power Authority (OPA), all of the output from Bruce A is effectively sold at a fixed price per MWh, adjusted for inflation annually on April 1. In addition, fuel costs are recovered from the OPA. In accordance with a 2007 contract amendment, effective April 1, 2008, the fixed price for output from Bruce A was $63.00 per MWh, an increase of $2.11 per MWh, subject to inflation adjustments from October 31, 2005.

Bruce A Fixed Price

	per MWh
April 1, 2008 – March 31, 2009	$63.00
April 1, 2007 – March 31, 2008	$59.69
April 1, 2006 – March 31, 2007	$58.63

Support payments received pursuant to the OPA contract are equal to the difference between the fixed prices under the OPA contract and spot market prices and 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. As at December 31, 2008, Bruce A had received $368 million towards this cap. Post-refurbishment prices will also be adjusted for capital cost variances associated with the refurbishment and restart projects.

Bruce B

Income from Bruce B is directly affected by fluctuations in wholesale spot market prices for electricity and overall plant availability, which in turn is affected by planned and unplanned maintenance.

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

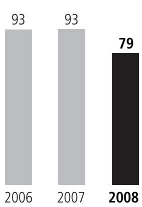
Bruce B Floor Price

	per MWh
April 1, 2008 – March 31, 2009	$47.66
April 1, 2007 – March 31, 2008	$46.82
April 1, 2006 – March 31, 2007	$45.99

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 have not included any amounts received pursuant to this floor mechanism. To further reduce its exposure to spot market prices, as at December 31, 2008, Bruce B had entered into fixed price sales contracts to sell forward approximately 12,460 GWh for 2009 and 7,100 GWh for 2010.

Plant Availability

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



Weighted average power plant availability for all plants, excluding Bruce Power, was 79 per cent in 2008 compared to 93 per cent in 2007 and 2006. Plant availability represents the percentage of time in a year that the plant is available to generate power whether actually running or not. Western Power's plant availability was affected negatively throughout 2008 and in late 2007 by an outage at the Cancarb power plant. Eastern Power achieved plant availability of 78 per cent in 2008, 18 per cent lower than 2007 as a result of outages experienced on Units 10 and 30 at Ravenswood throughout fourth quarter 2008 and a longer than expected outage at OSP in late 2008. Additionally, Bécancour, which had an availability of 97 per cent in 2007, is not included in Eastern Power's 2008 availability measurement as a result of a temporary suspension of power generation from the plant throughout 2008.

Weighted Average Plant Availability
Year ended December 31

	2008	2007	2006
Western Power	**87%**	90%	88%
Eastern Power	**78%**	96%	95%
Bruce Power	**86%**	86%	88%
All plants, excluding Bruce Power	**79%**	93%	93%
All plants	**83%**	91%	91%

Natural Gas Storage

TCPL owns or has rights to 120 Bcf of natural gas storage capacity in Alberta, including a 60 per cent ownership interest in CrossAlta, an independently operated storage facility. TCPL also has contracts for long-term, Alberta-based storage capacity from a third party, which expire in 2030, subject to early termination rights in 2015.

Natural Gas Storage Capacity

	Working Gas Storage Capacity (Bcf)	Maximum Injection/ Withdrawal Capacity (mmcf/d)
Edson	50	725
CrossAlta[1]	32	288
Third-party storage	38	630
	120	1,643

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

TCPL believes the market fundamentals for natural gas storage remain unchanged. The Company's gas storage capability helps balance seasonal and short-term supply and demand, and adds flexibility to the delivery 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 additional gas supplies be connected to North American markets. Energy's natural gas storage business operates independently from TCPL's regulated natural gas transmission business and from ANR's regulated storage business, which is included in TCPL's Pipelines segment.

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

TCPL offers a broad range of injection and withdrawal storage alternatives tailored to customer needs in short-term to multi-year contracts. Market volatility frequently creates arbitrage opportunities and TCPL's storage operations offer solutions to capture value from these short-term price movements. Earnings from third-party storage capacity contracts are recognized over the term of the contract. At December 31, 2008, TCPL had contracted approximately 70 per cent of the total 120 Bcf of working gas storage capacity in 2009 and 57 per cent of storage capacity in 2010.

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, TCPL locks in future positive margins, thereby effectively eliminating its exposure to natural gas seasonal price spreads.

These forward natural gas contracts provide highly effective economic hedges but do not meet the specific criteria for hedge accounting and, therefore, are recorded at their fair values based on the forward market prices for the contracted month of delivery. Changes in the fair value of these contracts are recorded in Revenues. Effective April 2007, TCPL 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. Changes in the fair value of inventory are recorded in Revenues. Changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sales contracts are excluded in determining comparable earnings as they are not representative of amounts that will be realized on settlement.

Natural Gas Storage operating income was $135 million in 2008, a decrease of $11 million compared to 2007. The decrease was primarily due to lower average storage values realized by CrossAlta, partially offset by higher earnings from the sale of proprietary natural gas at Edson in 2008. There were no net unrealized gains or losses in 2008 from changes in the fair value of proprietary natural gas forward purchase and sales contracts compared to net unrealized gains of $10 million in 2007.

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

ENERGY – OPPORTUNITIES AND DEVELOPMENTS

Ravenswood In August 2008, TCPL acquired the multiple-unit Ravenswood generating facility located in Queens, New York, which employs dual-fuel capable steam turbine, combined-cycle and combustion turbine technology. During 2008, Ravenswood operated under a tolling arrangement that existed at the date of acquisition and expired on December 31, 2008. Under the tolling arrangement, all energy generated from the facility was provided to Hess Corporation for a fixed operating fee. In January 2009, Ravenswood commenced earning revenues from the sale of energy generated from the facility into the New York market. TCPL's marketing operation located in Westborough, Massachusetts manages the marketing of output from Ravenswood.

The integration into TCPL's operations of the Ravenswood generating station, acquired in August 2008, is now complete. Shortly after closing the acquisition, TCPL experienced a forced outage event affecting one of the larger multiple generating units. The unit is currently undergoing repair and it is expected that the event will be insured both for physical damage and business interruption. Other refurbishment work is being undertaken at the station while the repair work is being completed and as a result, unit availability is expected to improve in the future.

Bruce Power Under a long-term agreement reached in 2005 between Bruce Power and the OPA, Bruce A has committed to refurbish and restart the currently idle Units 1 and 2, extend the operating life of Unit 3 with a full refurbishment and replace the steam generators on Unit 4. Bruce Power and the OPA amended the Bruce A refurbishment agreement in 2007 to allow for a full refurbishment of Unit 4, which will extend the expected operating life of the unit. Under the 2007 amendment, the OPA had the option to elect, prior to April 1, 2008, to proceed with a three-unit refurbishment and restart program instead of the revised four-unit program. The OPA chose to not exercise this option and instead elected to proceed with the four-unit refurbishment and restart program.

In fourth quarter 2008, Bruce Power completed a review of the operating life estimates for Units 3 and 4. Unit 3 is now expected to remain in commercial service until 2011, which provides the benefit of nearly two additional years of power generation before the unit commences an expected 36 month refurbishment. After the refurbishment, the operating life of Unit 3 is expected to be extended to 2038 from 2037. In addition, Unit 4 is now expected to remain in commercial service until 2016, providing nearly seven years of generation before the unit commences a similar refurbishment period, after which, the estimated operating life of Unit 4 is expected to be extended to 2042 from 2036.

The capital cost for the refurbishment and restart of Bruce A Units 1 and 2 is expected to be approximately $3.4 billion, based on a comprehensive review in January 2008 of the estimated costs to complete the project, which is an increase from the original cost estimate of $2.75 billion. TCPL's share is expected to be approximately $1.7 billion, compared to an original estimate of $1.4 billion. The project cost increases are subject to the capital cost risk- and reward-sharing mechanism under TCPL's 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, 2008, Bruce A had incurred $2.6 billion in costs with respect to the refurbishment and restart of Units 1 and 2 and approximately $200 million for the refurbishment of Units 3 and 4.

Portlands Energy Construction continued in 2008 on Portlands Energy. The facility was operational in single-cycle mode in the summer of 2008 and is expected to be fully commissioned in its combined-cycle mode in first quarter 2009. Portlands Energy will provide power under a 20-year Accelerated Clean Energy Supply contract with the OPA. The expected capital cost is $730 million, of which TCPL's portion is 50 per cent.

Coolidge In May 2008, the Phoenix, Arizona-based utility, Salt River Project, signed a 20-year power purchase contract to secure 100 per cent of the output from the simple-cycle natural gas-fired peaking power facility currently under development. In December 2008, the Arizona Corporation Commission granted a Certificate of Environmental Compatibility approving construction of the facility. Construction is expected to begin in the summer of 2009 and the facility is expected to be commissioned in 2011.

Halton Hills Construction of Halton Hills continued in 2008. The project includes the construction and operation of a natural gas-fired power plant near the town of Halton Hills, Ontario. TCPL 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 Carleton wind farm commenced commercial operation in November 2008, providing up to 109 MW of power to the Hydro-Québec grid. Carleton is the third phase of the six-phase, multi-year Cartier Wind project, located in the Gaspé region of Québec. The first two phases, Baie-des-Sables and Anse-á-Valleau, went into service in November of 2006 and 2007, respectively, generating up to 110 MW and 101 MW of power, respectively. 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. TCPL has a 62 per cent ownership interest in these wind farms.

Kibby Wind In July 2008, the State of Maine's Land Use Regulation Commission approved the final development plan submitted by TCPL to build, own and operate a wind farm, located in the Kibby and Skinner townships in Maine. Construction of the facilities at a cost of approximately US$320 million began in July 2008 and commissioning of the first phase is expected to begin in fourth quarter 2009.

Bécancour TCPL entered into an agreement with Hydro-Québec in November 2007 to temporarily suspend all electricity generation from the Bécancour power plant during 2008. In 2008, the agreement was extended through to December 2009. In 2009, TCPL will continue to receive payments under the agreement similar to those that would have been received under the normal course of operation.

Power Transmission Line Projects TCPL is pursuing proposals to build, own and operate power transmission lines, including the Zephyr and Chinook transmission line projects. The projects are each proposed 500 kilovolt (kV) high voltage direct current (HVDC) transmission lines originating in Wyoming and Montana, respectively, and terminating in Nevada. If constructed, each project would cost approximately US$3 billion and be capable of delivering 3,000 MW of power. In December 2008, TCPL filed applications for both projects requesting approval from the FERC to charge negotiated rates and to proceed with an open season in the spring of 2009, with 50 per cent of the capacity of each line already pre-subscribed for a period of 25 years. In February 2009, the FERC approved both applications. Pending successful completion of the open seasons, regulatory work could commence later in 2009, followed by construction commencing in 2012 and a potential in-service date of late 2014.

TCPL is pursuing a proposal to build NorthernLights, a 500 kV HVDC electric transmission line running from central Alberta to a terminal in southern Alberta and interconnecting with the Pacific Northwest. NorthernLights is expected to cost approximately $2 billion and provide up to 3,000 MW of power.

Broadwater LNG In March 2008, the FERC authorized the construction and operation of Broadwater, subject to conditions. In April 2008, the New York Department of State determined that construction and operation of the project would not be consistent with the State's coastal zone policies. As a result of this unfavourable decision, TCPL wrote down $27 million after tax ($41 million pre-tax) of costs for Broadwater that had been capitalized to March 31, 2008. TCPL has appealed the determination of the New York Department of State to the U.S. Department of Commerce and a decision is expected in early 2009.

ENERGY – BUSINESS RISKS

Fluctuating Power and Natural Gas Market Prices

TCPL 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 uncontracted power sales volumes in Western Power and Eastern Power and through its investment in Bruce Power. In addition, with the acquisition of Ravenswood, at December 31, 2008, Eastern Power significantly increased its level of uncontracted sales volumes, which are subject to price volatility. 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 subject to a floor price mechanism that are sold into the wholesale power spot market under contract price terms with the OPA, 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.

Liquidity Risk

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

Plant Availability

Maintaining plant availability is essential to the continued success of the Energy business. Plant operating risk is mitigated through a commitment to TCPL'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 TCPL 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.

Hydrology

TCPL'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, Québec, Maine and Arizona, 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 TCPL'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.

Regulation of Power Markets

TCPL 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 affect TCPL as a generator and marketer of electricity. These may be in the form of market rule changes, price caps, emission controls, unfair cost allocations to generators and attempts by others to take out-of-market actions to build excess generation that negatively affects the price for capacity or energy, or both. In addition, TCPL's development projects rely on an orderly permitting process and any disruption to that process can have negative effects on project schedule and cost. TCPL 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 additional risks and managing risks in the Energy business.

ENERGY – OUTLOOK

TCPL assumes that its operations in 2009 will be materially consistent with those in 2008 and includes the positive impact of a full year of earnings from Ravenswood, incremental earnings from Portlands Energy, which is expected to be commissioned in first quarter 2009, and a decrease in planned outages at Bruce Power. These positive impacts are expected to be partially offset by a return to more normal hydrology levels at TC Hydro from the record levels experienced in 2008. In addition, the current economic climate is negatively affecting demand, liquidity and prices in commodity markets in which TCPL operates.

Although TCPL has sold forward significant output from its power plants and Alberta PPAs, as well as capacity from its natural gas storage facilities, operating income in 2009 can be affected by changes in the spot market price of power, market heat rates, hydrology, forward capacity payments, natural gas storage spreads and unplanned outages. Operating income from Energy's U.S. operations is affected by changes in the U.S./Canadian dollar exchange rates.

Other factors such as plant availability, regulatory changes, weather, currency movements, and overall stability of the energy industry can also affect 2009 operating income. Refer to the "Energy – Business Risks" section of this MD&A for a complete discussion of these factors.

Following the expiry of the Ravenswood tolling arrangement with Hess Corporation on December 31, 2008, TCPL will manage the ongoing marketing of the Ravenswood plant output in the same manner as it does with other generation assets in the U.S. Northeast. Dependent on market liquidity and other factors, a significant portion of the electricity generated by the Ravenswood facility in 2009 and beyond may be sold at spot prices. As noted in the "Energy – Business Risks" section of this MD&A, spot prices for electricity are subject to change depending on underlying energy commodity prices, available supply, demand and other factors.

Capital Expenditures
Energy's total capital expenditures in 2008 were $4.3 billion, including the acquisition of Ravenswood for $3.1 billion. Energy's overall capital spending in 2009 is expected to be approximately $1.4 billion, including cash calls for the Bruce A refurbishment and restart project and continued construction at Coolidge, Cartier Wind, Kibby Wind and Halton Hills.

CORPORATE

CORPORATE RESULTS
Year ended December 31 *(millions of dollars)*

	2008	2007	2006
Indirect financial charges and non-controlling interests	**310**	266	139
Interest income and other	**3**	(81)	(43)
Income taxes	**(191)**	(127)	(61)
Comparable Expenses[1]	**122**	58	35
Income tax reassessments and adjustments	**(26)**	(68)	(72)
Net Expenses/(Earnings), after income taxes	**96**	(10)	(37)

[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 the Company maintains, the degree to which the Company is affected by fluctuations in interest and foreign exchange rates and the amount of interest capitalized for projects under construction.

Interest Income and Other
Interest Income and Other includes interest earned on invested cash balances and income tax refunds. Also included are foreign exchange gains and losses related to translation of foreign-denominated working capital and derivatives used to manage the Company's exposure to U.S. dollar net income.

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 expenses in Corporate were $96 million in 2008 compared to net earnings of $10 million and $37 million in 2007 and 2006, respectively.

Corporate's net expenses in 2008 included favourable income tax reassessments and adjustments of $26 million compared to $68 million in 2007. Excluding these income tax adjustments, Corporate's comparable expenses increased $64 million in 2008 compared to 2007. The increase in comparable expenses was primarily due to net unrealized losses of $39 million after tax from changes in the fair value of derivatives, which are used to manage the Company's exposure to rising interest rates but do not qualify as hedges for accounting purposes. The fair value of these derivatives was negatively impacted as interest rates dropped to historic lows late in fourth quarter 2008. In addition, higher financial charges resulting from financing the Company's 2008 capital program, including the Ravenswood acquisition, and higher losses from the change in fair value of derivatives used to manage the Company's exposure to foreign exchange rate fluctuations were partially offset by increased capitalization of interest to finance a larger capital spending program. The losses from the foreign exchange derivatives were partially offset by the positive impact of a stronger U.S. dollar reported in the Pipelines and Energy businesses.

Corporate's net earnings in 2007 and 2006 included favourable income tax reassessments and adjustments of $68 million and $72 million, respectively. Excluding these income tax adjustments, Corporate's comparable expenses increased $23 million in 2007 compared to 2006. Net unrealized gains from the change in fair value of 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 ANR acquisition and additional ownership interest in Great Lakes.

CORPORATE – OUTLOOK

Corporate's net expenses in 2008 included certain favourable income tax reassessments and other impacts, including the $39 million net unrealized losses on interest rate derivatives, that are not expected to recur in 2009. Financing costs associated with debt issued in 2008 and 2009, and together with additional debt expected to be issued in 2009 to partially finance the Company's capital programs are expected to increase financial charges in Corporate in 2009. However, the increased charges are expected to be primarily offset by capitalized interest for projects under construction. Corporate's results could also be affected by debt levels, interest rates, foreign exchange rates 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 primarily mitigated by offsetting U.S.-dollar exposures in certain of TCPL's other businesses and by the Company's hedging activities.

DISCONTINUED OPERATIONS

The $28 million income from discontinued operations in 2006 reflected bankruptcy settlements with Mirant related to TCPL's Gas Marketing business, which was sold in 2001.

LIQUIDITY AND CAPITAL RESOURCES

Global financial markets are in turmoil, however, TCPL's financial position and ability to generate cash from its operations in the short and long term to provide liquidity and to maintain financial capacity and flexibility to provide for planned growth remains sound and consistent with recent years. TCPL's liquidity position remains solid, underpinned by highly predictable cash flow from operations, significant cash balances on hand from recent securities issues, as well as committed revolving bank lines of US$1.0 billion, $2.0 billion and US$300 million, maturing in November 2010, December 2012 and February 2013, respectively. To date, no draws have been made on these facilities as TCPL has continued to have largely uninterrupted access to the Canadian commercial paper market on competitive terms. An additional $50 million and US$320 million of capacity remains available on committed bank facilities at TCPL-operated affiliates with maturity dates from 2010 through 2012. TCPL further strengthened its liquidity and financial position through additional financing transactions in 2008 and early 2009, as discussed below. TCPL's liquidity, market and other risks are discussed further in the "Risk Management and Financial Instruments" section of this MD&A.

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

	2008	2007	2006
Funds generated from operations[1]	**2,992**	2,603	2,374
(Increase)/decrease in operating working capital	**(188)**	215	(300)
Net cash provided by operations	**2,804**	2,818	2,074

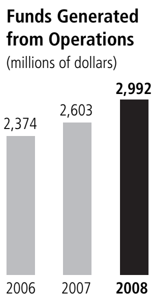
[1] Refer to the "Non-GAAP Measures" section of this MD&A for further discussion of funds generated from operations.

HIGHLIGHTS

Investing Activities
- Capital expenditures and acquisitions, including assumed debt, totalled approximately $15.3 billion over the three-year period ending December 31, 2008.

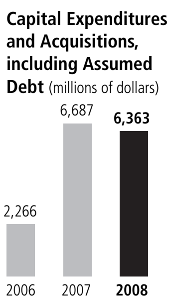
Dividend
- On February 2, 2009, TCPL's Board of Directors declared a dividend for the quarter ending March 31, 2009 in an aggregate amount equal to the quarterly dividend to be paid on TransCanada's issued and outstanding common shares at the close of business on March 31, 2009. The Board also declared regular dividends on TCPL's preferred shares.

Funds Generated from Operations



Funds Generated from Operations were $3.0 billion in 2008 compared to $2.6 billion and $2.4 billion, in 2007 and 2006, respectively. The increase in 2008 compared to 2007 was primarily due to proceeds from higher operating earnings and the Calpine bankruptcy settlements. The Energy business was the primary source of the increase in 2008 compared to 2007, partially offset by a reduced contribution from Corporate. The Pipelines business and growth in Energy's operations were the main drivers for the increase in 2007 compared to 2006.

Investing Activities



Capital expenditures totalled $3,134 million in 2008 compared to $1,651 million in 2007 and $1,572 million in 2006. Expenditures in 2008 and 2007 related primarily to the refurbishment and restart at Bruce Power, development of new pipelines, including Keystone, construction of new power facilities, expansion of existing pipelines and maintenance and capacity projects in the Pipelines business. Expenditures in 2006 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.

TCPL acquired Ravenswood from National Grid plc on August 26, 2008 for US$2.9 billion, subject to certain post-closing adjustments.

In accordance with TCPL's agreement to increase its ownership interest in Keystone up to 79.99 per cent from 50 per cent, TCPL has funded $362 million of Keystone cash calls since September 30, 2008. This has resulted in an acquisition of an incremental 12 per cent ownership interest for $176 million, bringing TCPL's ownership interest to 62 per cent at December 31, 2008. The Keystone agreement is discussed further in the "Pipelines" section of this MD&A.

In 2007, TCPL acquired ANR and an additional 3.6 per cent interest in Great Lakes from El Paso Corporation for US$3.4 billion, including US$491 million of assumed long-term debt. PipeLines LP acquired the remaining 46.4 per cent of Great Lakes from El Paso Corporation for US$942 million, including US$209 million of assumed long-term debt. In 2007, PipeLines LP purchased Sierra Pacific Resources' remaining one per cent ownership interest in Tuscarora for approximately $2 million. In a separate transaction in 2007, PipeLines LP also purchased TCPL'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.

In 2006, PipeLines LP acquired an additional 49 per cent interest in Tuscarora for US$100 million and also assumed 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. TCPL sold its 17.5 per cent general partner interest in Northern Border Partners, L.P. for proceeds of $35 million, net of current tax.

Financing Activities

In 2008, TCPL issued Long-Term Debt of $2.2 billion and increased Notes Payable by $1.7 billion. Its proportionate share of Long-Term Debt issued by joint ventures was $173 million. Also in 2008, the Company reduced its Long-Term Debt by $840 million and its proportionate share of the Long-Term Debt of Joint Ventures by $120 million.

At December 31, 2008, total unsecured revolving and demand credit facilities of $4.2 billion were available to support the Company's commercial paper programs and for general corporate purposes. These credit facilities include the following:

- a $2.0 billion committed, syndicated revolving credit facility, maturing December 2012.

- a US$300 million committed, syndicated revolving facility, maturing February 2013. This facility is part of the US$1.0 billion TransCanada PipeLine USA Ltd. credit facility discussed below under the heading "2007 Long-Term Debt Financing Activities".
- a US$1.0 billion committed, extendible, expandable, unsecured bank facility, established in fourth quarter 2008, bearing interest at a floating rate plus a margin, with an initial term of 364 days and a one-year term renewal at the option of the borrower. The facility will support a new commercial paper program dedicated to funding a portion of expenditures for Keystone and for general partnership purposes.
- demand lines totaling $0.6 billion, which support the issuance of letters of credit and provide additional liquidity. The Company had used approximately $433 million of these total lines of credit for letters of credit at December 31, 2008.

Related Party Debt Financings
Related party transactions consist of amounts due to and from TransCanada as well as accrued interest income and expense.

At December 31, 2008, TransCanada had issued discount notes to TCPL for $1.5 billion (2007 – $1.2 billion). The notes bear interest at 2.1 per cent, mature in June 2009 and were used for general corporate purposes.

At December 31, 2007, TransCanada had issued two promissory notes to TCPL totalling $181 million. These notes were non-interest bearing and were repaid in December 2008. These notes were used for general corporate purposes.

In February 2007, TCPL issued a promissory note to TransCanada for US$700 million bearing interest at LIBOR plus 32.5 basis points to partially finance the acquisitions of ANR and additional interest in Great Lakes. The US$370 million outstanding at December 31, 2007 was fully repaid on January 7, 2008.

TranCanada established a $2.5 billion, unsecured credit facility agreement with TCPL, bearing interest at the Reuters prime rate or Bankers' Acceptance rate plus 65 basis points, at TCPL's option. The funds advanced under this agreement can be used to repay indebtedness, make partner contributions to Bruce A, or for working capital and general corporate purposes. At December 31, 2008, $1.6 billion was outstanding under this credit facility (2007 – $1.3 billion). This credit agreement matures on December 15, 2009.

In May 2003, TCPL established a demand revolving credit facility with TransCanada for general corporate purposes at $500 million, or a U.S. dollar equivalent amount, bearing interest at the Royal Bank of Canada prime rate per annum or the U.S. base rate per annum. As at December 31, 2008, $200 million was outstanding on this facility (2007 – $207 million).

In 2008, Financial Charges included $76 million (2007 – $72 million) of interest expense and $55 million (2007 – $30 million) of interest income as a result of transactions with TransCanada. At December 31, 2008, Accounts Payable included $2 million of interest payable to TransCanada (2007 – $5 million).

Short-Term Debt Financing Activities
In June 2008, TCPL executed an agreement with a syndicate of banks for a US$1.5 billion committed, unsecured, one-year bridge loan facility, at a floating interest rate based on London Interbank Offered Rate (LIBOR) plus 30 basis points. The facility is extendible at the option of the Company for an additional six-month term at LIBOR plus 35 basis points. In August 2008, the Company used US$255 million from this facility to fund a portion of the Ravenswood acquisition and cancelled the remainder of the commitment. At December 31, 2008, the US$255 million remained outstanding on the facility.

2009 and 2008 Long-Term Debt Financing Activities
On February 17, 2009, the Company completed the issuance of Medium-Term Notes of $300 million and $400 million maturing in February 2014 and February 2039, respectively, and bearing interest at 5.05 per cent and 8.05 per cent,

respectively. The proceeds are expected to be used to fund the Alberta System and Canadian Mainline rate bases. These notes were issued under a $1.5 billion debt shelf prospectus filed in Canada in March 2007.

On January 9, 2009, the Company issued Senior Unsecured Notes of US$750 million and US$1.25 billion maturing in January 2019 and January 2039, respectively, and bearing interest at 7.125 per cent and 7.625 per cent, respectively. The proceeds from these notes are expected to be used to partially fund TCPL's capital projects and retire mature debt obligations, and for general corporate purposes. These notes were issued under a US$3.0 billion debt shelf prospectus filed in January 2009. Following these issues, the Company has unutilized capacity of US$1.0 billion remaining under its January 2009 U.S. debt shelf prospectus.

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

In August 2008, TCPL issued US$850 million and US$650 million of Senior Unsecured Notes maturing in August 2018 and August 2038, respectively, and bearing interest at 6.50 per cent and 7.25 per cent, respectively. The proceeds from these notes were used to partially fund the Ravenswood acquisition and for general corporate purposes. These notes were issued under the September 2007 debt shelf prospectus filed in the U.S. Following these issuances, the Company had fully utilized the capacity of its September 2007 U.S. debt shelf prospectus.

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

2007 Long-Term Debt Financing Activities

In 2007, TCPL 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 $412 million and its proportionate share of the Long-Term Debt of Joint Ventures by $157 million.

In October 2007, TCPL issued US$1.0 billion of Senior Unsecured Notes under a US$2.5 billion debt shelf prospectus filed in the U.S. in September 2007. These notes mature on October 15, 2037 and bear interest at a rate of 6.20 per cent.

In July 2007, TCPL exercised its rights to redeem the US$460 million 8.25 per cent Preferred Securities due 2047. The Preferred Securities were redeemed for cash, at par, as part of a 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, the Company 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 interest rate of three-month LIBOR plus 221 basis points. The Junior Subordinated Notes are subordinated to all existing and future senior indebtedness, are effectively subordinated to all indebtedness and obligations of the Company and are callable at the Company's option at any time on or after May 15, 2017 at the principal amount plus accrued and unpaid interest.

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, 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. The revolving portion of the committed facility and the draw on the demand line were subsequently repaid. In 2008, the maturity date of the revolving portion of the facility was extended to February 2013.

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.

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, the Company issued Long-Term Debt of $2.1 billion and 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 Senior Unsecured Notes due 2036. In October 2006, TCPL issued $400 million of 4.65 per cent 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, 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.

2008 Equity Financing Activities

In 2008, TCPL issued 66.3 million common shares to TransCanada for proceeds of approximately $2.4 billion.

Commencing in 2007, TransCanada's Board of Directors authorized the issuance of common shares from treasury at a discount to participants in TransCanada's DRP. Under this plan, eligible TCPL preferred shareholders may reinvest their dividends and make optional cash payments to obtain additional TransCanada common shares. The DRP shares are provided to the participants at a discount to the average market price in the five days before dividend payment. The discount was set at two per cent commencing with the dividend payable in April 2007 and was increased to three per cent for the dividend payable in January 2009. Prior to the April 2007 dividend, TransCanada purchased shares on the open market and provided them to DRP participants at cost. TransCanada reserves the right to alter the discount or return to purchasing shares on the open market at any time.

2007 Equity Financing Activities

In 2007, TCPL issued 48.2 million common shares to TransCanada for proceeds of approximately $1.8 billion. The proceeds were used towards financing the acquisition of ANR and Great Lakes.

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

Dividends
Cash dividends on common and preferred shares amounting to $817 million were paid in 2008 compared to $725 million in 2007 and $639 million in 2006. The increase in dividends in 2008 compared to 2007 was primarily due to a greater number of shares outstanding.

On February 2, 2009, TCPL's Board of Directors declared a dividend for the quarter ending March 31, 2009 in an aggregate amount equal to the quarterly dividend to be paid on TransCanada's issued and outstanding common shares at the close of business on March 31, 2009. The Board also declared regular dividends on TCPL's preferred shares.

Issuer Ratings
TCPL's issuer rating assigned by Moody's Investors Service (Moody's) is Baa1 with a stable outlook. TCPL's senior unsecured debt is rated A with a stable outlook by DBRS, A3 with a stable outlook by Moody's, and A− with a stable outlook by Standard and Poor's.

CONTRACTUAL OBLIGATIONS

Obligations and Commitments
At December 31, 2008, the Company had $16.2 billion of total Long-Term Debt and $1.2 billion of Junior Subordinated Notes, compared to $12.9 billion of total Long-Term Debt and $1.0 billion of Junior Subordinated Notes at December 31, 2007. TCPL's share of the total debt of joint ventures, including capital lease obligations, was $1.1 billion at December 31, 2008, compared to $903 million at December 31, 2007. Total amounts due to TransCanada were $1.8 billion at December 31, 2008 compared to $1.9 billion at December 31, 2007. Total Notes Payable, including TCPL's proportionate share of the notes payable of joint ventures, were $1.7 billion at December 31, 2008, compared to $55 million at December 31, 2007. TCPL 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
Due to TransCanada Corporation	1,821	1,821	–	–	–
Long-term debt[1]	18,208	980	1,787	2,684	12,757
Capital lease obligations	235	13	25	38	159
Operating leases[2]	403	28	56	66	253
Purchase obligations	12,246	3,926	2,595	1,761	3,964
Other long-term liabilities reflected on the balance sheet	610	12	29	34	535
Total contractual obligations	33,523	6,780	4,492	4,583	17,668

(1) Includes Junior Subordinated Notes.

(2) Represents future annual payments, net of sub-lease receipts, for various premises, services and equipment. The operating lease agreements for premises, services and equipment expire at various dates through 2035, with an option to renew certain lease agreements for one to ten years.

TCPL's commitments under the Alberta PPAs are considered to be operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Future payments under these PPAs have been excluded from the above table, as these payments are dependent upon plant availability, among other factors. The amount of power purchased under the PPAs in 2008 was $471 million (2007 – $440 million; 2006 – $499 million).

At December 31, 2008, scheduled principal repayments and interest payments related to amounts due to TransCanada Corporation, long-term debt and the Company's proportionate share of the long-term debt of joint ventures were as follows:

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

		Payments Due by Period			
	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Due to TransCanada Corporation	1,821	1,821	–	–	–
Long-term debt[1]	16,154	786	1,545	2,550	11,273
Junior subordinated notes	1,213	–	–	–	1,213
Long-term debt of joint ventures	841	194	242	134	271
Total principal repayments	20,029	2,801	1,787	2,684	12,757

(1) Includes Junior Subordinated Notes.

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 amounts due to TransCanada Corporation	92	92	–	–	–
Interest payments on long-term debt	14,508	1,072	1,995	1,794	9,647
Interest payments on junior subordinated notes	662	78	156	156	272
Interest payments on long-term debt of joint ventures	328	61	76	56	135
Total interest payments	15,590	1,303	2,227	2,006	10,054

At December 31, 2008, the Company's approximate future purchase obligations were as follows:

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

		Payments Due by Period			
	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Pipelines					
Transportation by others[2]	931	260	396	199	76
Capital expenditures[3][4]	2,317	2,092	155	70	–
Other	6	3	2	1	–
Energy					
Commodity purchases[5]	6,711	945	1,394	1,284	3,088
Capital expenditures[3][6]	1,049	509	456	61	23
Other[7]	1,133	88	151	124	770
Corporate					
Information technology and other	99	29	41	22	7
Total purchase obligations	12,246	3,926	2,595	1,761	3,964

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

(2) Rates are based on known 2009 levels. Beyond 2009, 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 capital projects with cash from operations and, if necessary, new debt and equity.

(4) Primarily consists of capital expenditures related to TCPL's share of the construction costs of Keystone, North Central Corridor 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 TCPL's share of the construction costs of Coolidge, Bruce Power, the remaining Cartier Wind projects, Halton Hills and Portlands Energy.

(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.

TCPL 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.

In 2009, TCPL expects to make funding contributions to the Company's pension and other post-retirement benefit plans in the amount of approximately $140 million and $27 million, respectively. This represents an increase from total funding contributions of $90 million in 2008 and is attributable primarily to significantly reduced investment performance and plan experience being different than expectations. TCPL's proportionate share of funding contributions expected to be made by joint ventures to their respective pension and other post-retirement benefit plans in 2009 is approximately $37 million and $4 million, respectively, compared to actual total contributions of $42 million in 2008.

The next actuarial valuation for the Company's pension and other post-retirement benefit plans is expected to be carried out as at January 1, 2010. Primarily as a result of the significantly lower performance of the pension plan assets in 2008, it is expected that funding requirements for these plans could continue at the anticipated 2009 level for the next several years to amortize solvency deficiencies in addition to normal costs. The Company's net benefit cost is expected to remain at 2008 levels. However, the net benefit cost and the amount of funding contributions received will be dependent on various factors, including future investment returns achieved on plan assets, the level of interest rates, changes to plan design and actuarial assumptions, actual plan experience versus projections and amendments to pension plan regulations and legislation. Increases in the level of required plan funding are not expected to have a material impact on the Company's liquidity.

Bruce Power

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

Year ended December 31 (millions of dollars)

2009	204
2010	49
2011	2
	255

Aboriginal Pipeline Group

Under its agreement with the APG, TCPL agreed to finance the APG's one-third share of the MGP project's predevelopment costs. These costs are currently forecast to be between $150 million and $200 million, on a cumulative basis, depending on the pace of project development. As at December 31, 2008, the Company had advanced $140 million of this total. This agreement is discussed further in the "Pipelines – Opportunities and Developments" section of this MD&A.

Contingencies

In April 2008, the Ontario Court of Appeal dismissed an appeal filed by the Canadian Alliance of Pipeline Landowners' Associations (CAPLA). CAPLA filed the appeal as a result of a decision by the Ontario Superior Court in November 2006 to dismiss CAPLA's class action lawsuit against TCPL and Enbridge Inc. for damages 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*. The Ontario Court of Appeal's decision is final and binding as CAPLA did not seek any further appeal within the time frame allowed.

TCPL is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2008, the Company had recorded liabilities of approximately $86 million representing the Company's estimate of the amount it expects to expend to remediate certain sites. However, additional liabilities may be incurred as more assessments occur and remediation efforts continue.

TCPL 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

TCPL, Cameco Corporation and BPC have 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 2010 to perpetuity. In addition, TCPL and BPC have severally guaranteed one-half of certain contingent financial obligations related to an agreement with the OPA to refurbish and restart Bruce A power generation units. The guarantees were provided as part of the reorganization of Bruce Power in 2005 and have terms ending in 2019. TCPL's share of the potential exposure under these Bruce A and Bruce B guarantees was estimated at December 31, 2008 to range from $711 million to a maximum of $750 million. The fair value of these guarantees is estimated to be $17 million.

The Company and its partners in certain jointly owned entities have severally as well as jointly and severally guaranteed the financial performance of these entities related primarily to construction projects, redelivery of natural gas, PPA payments and the payment of liabilities. TCPL's share of the potential exposure under these guarantees was estimated at December 31, 2008 to range from $688 million to a maximum of $1.4 billion. For certain of these entities, any payments made by TCPL under these guarantees in excess of its ownership interest are to be reimbursed by its partners. Deferred Amounts includes $9 million for the fair value of these joint and several guarantees.

TCPL has guaranteed a subsidiary's equity undertaking to support the payment, under certain conditions, of principal and interest on US$43 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, TCPL 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 TCPL under this agreement would 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 TCPL. The debt matures in 2010. The Company has made no provision related to this guarantee.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

FINANCIAL RISKS AND FINANCIAL INSTRUMENTS

Risk Management Overview

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

Risk management strategies, policies and limits are designed to ensure TCPL's risks and related exposures are in line with the Company's business objectives and risk tolerance. Risks are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by risk management and internal audit personnel. The Board of Directors' Audit Committee oversees how management monitors compliance with risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework. Internal audit personnel assist the Audit Committee in its oversight role by performing regular and ad-hoc reviews of risk management controls and procedures, the results of which are reported to the Audit Committee. The Board of Directors also has a Governance Committee that assists in overseeing the risk management activities of TCPL. The Governance Committee monitors, reviews with management and makes recommendations related to TCPL's risk management programs and policies on an ongoing basis.

Market Risk

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

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

- Forwards and futures contracts – contractual agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future. TCPL enters into foreign exchange and commodity forwards and futures to mitigate the impact of volatility in foreign exchange rates and commodity prices.
- Swaps – contractual agreements between two parties to exchange streams of payments over time according to specified terms. The Company enters into interest rate, cross-currency and commodity swaps to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.

- Options – contractual agreements to convey the right, but not the obligation, of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. The Company enters into option agreements to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.

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

- Subject to the Company's overall risk management policies, the Company commits a significant portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to mitigate price risk in its asset portfolio.
- The Company purchases a portion of the natural gas and oil products required for its power plants or enters into contracts that base the sales price of electricity on the cost of natural gas, effectively locking in a margin. A significant portion of the electricity needed to fulfill the Company's power sales commitments is purchased with contracts or fulfilled through power generation, thereby reducing the Company's exposure to fluctuating commodity prices.
- The Company enters into offsetting or back-to-back positions and derivative financial instruments to manage price risk exposure in power and natural gas commodities created by certain fixed and variable pricing arrangements for different pricing indices and delivery points.

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

Natural Gas Inventory Price Risk
At December 31, 2008, $76 million (2007 – $190 million) of proprietary natural gas inventory was included in Inventories. TCPL measures its proprietary natural gas inventory held in storage at the one-month forward price for natural gas less selling costs. The Company did not have any proprietary natural gas inventory held in storage prior to April 2007. In 2008, the net change in fair value of proprietary natural gas held in inventory was a net unrealized loss of $7 million (2007 – nil), which was recorded as a decrease to Revenue and Inventory. In 2008, the net change in fair value of natural gas forward purchases and sales contracts was a net unrealized gain of $7 million (2007 – $10 million) which was included in Revenues.

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

A portion of TCPL's earnings from its Pipelines and Energy operations is generated in U.S. dollars and is subject to currency fluctuations. The performance of the Canadian dollar relative to the U.S. dollar can affect TCPL's earnings. This foreign exchange impact is offset by certain related debt and financing costs being denominated in U.S. dollars and by the Company's hedging activities. Due to its increased U.S. operations, TCPL has a greater exposure to U.S. currency 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 debt and other U.S. dollar-denominated transactions, and to manage the interest rate exposure of the Canadian Mainline, Alberta System and Foothills operations. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms. These gains and losses are deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers in accordance with the terms of the shipping agreements.

TCPL 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 this risk.

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 foreign exchange contracts, cross-currency interest rate swaps and foreign exchange options. At December 31, 2008, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $7.2 billion (US$5.9 billion) (2007 – $4.3 billion (US$4.4 billion)) and a fair value of $5.9 billion (US$4.8 billion) (2007 – $4.4 billion (US$4.5 billion)). In January 2009, the Company issued an additional US$2.0 billion of long-term debt and designated it as a hedge of the net U.S. dollar investment in foreign operations. At December 31, 2008, $254 million was included in Deferred Amounts for the fair value of the forwards, swaps and options used to hedge the Company's net U.S. dollar investment in foreign operations.

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

Asset/(Liability) December 31 *(millions of dollars)*	**2008** **Fair Value**	**2008** **Notional or Principal Amount**	2007 Fair Value	2007 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2009 to 2014)	**(218)**	**U.S. 1,650**	77	U.S. 350
U.S. dollar forward foreign exchange contracts (maturing 2009)	**(42)**	**U.S. 2,152**	(4)	U.S. 150
U.S. dollar options (maturing 2009)	**6**	**U.S. 300**	3	U.S. 600
	(254)	**U.S. 4,102**	76	U.S. 1,100

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

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

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

During the deterioration of global financial markets in 2008, TCPL continued to closely monitor and reassess the creditworthiness of its counterparties, including financial institutions. This has resulted in TCPL reducing or mitigating its exposure to certain counterparties where it is deemed warranted and permitted under contractual terms. As part of its ongoing operations, TCPL must balance its market risk and counterparty credit risk when making business decisions.

Certain subsidiaries of Calpine filed for bankruptcy protection in both Canada and the U.S. in 2005. Gas Transmission Northwest Corporation (GTNC) and Portland Natural Gas Transmission System (PNGTS) reached agreements with Calpine for allowed unsecured claims in the Calpine bankruptcy. In February 2008, GTNC and PNGTS received initial distributions of 9.4 million common shares and 6.1 million common shares of Calpine, respectively, which represented approximately 85 per cent of their agreed-upon claims. In 2008, these shares were subsequently sold into the open market and resulted in total pre-tax gains of $279 million. Claims by NOVA Gas Transmission Limited and Foothills Pipe Lines (South B.C.) Ltd. for $32 million and $44 million, respectively, were received in cash in January 2008 and will be passed on to shippers on these systems. At December 31, 2008, $22 million remained in regulatory liabilities for these claims.

Liquidity Risk

Liquidity risk is the risk that TCPL 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, under both normal and stressed conditions, it always has sufficient cash and credit facilities to meet its obligations when due without incurring unacceptable losses or damage to the Company's reputation.

Management forecasts cash flows for a period of 12 months to identify financing requirements. These requirements are then managed through a combination of committed and demand credit facilities and access to capital markets. The Company's liquidity and cash flow management is also discussed in the "Liquidity and Capital Resources" and "Contractual Obligations" sections of this MD&A.

Fair Values

The fair value of financial instruments included in Cash and Cash Equivalents, Accounts Receivable, Other Assets, Notes Payable, Accounts Payable, Accrued Interest and Deferred Amounts approximates their carrying amounts due to the nature of the item and/or the short time to maturity. The fair value of foreign exchange and interest rate derivatives has been calculated using year-end market rates. The fair value of power, natural gas and oil products derivatives has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes are used. Credit risk has been taken into consideration when calculating fair values.

Valuation techniques that refer to observable market data or estimated market prices may also be used to calculate fair value. 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, was estimated by discounting future payments of interest and principal at estimated interest rates that were made available to the Company.

Non-Derivative Financial Instruments Summary

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

	2008		2007	
December 31 *(millions of dollars)*	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial Assets(1)				
Cash and cash equivalents	**1,300**	**1,300**	504	504
Accounts receivable and other assets(2)(3)	**1,404**	**1,404**	1,231	1,231
Due from TransCanada Corporation	**1,529**	**1,529**	1,407	1,407
Available-for-sale assets(2)	**27**	**27**	17	17
	4,260	**4,260**	3,159	3,159
Financial Liabilities(1)(3)				
Notes payable	**1,702**	**1,702**	55	55
Accounts payable and deferred amounts(4)	**1,364**	**1,364**	1,192	1,192
Accrued interest	**361**	**361**	265	265
Due to TransCanada Corporation	**1,821**	**1,821**	1,879	1,879
Long-term debt and junior subordinated notes	**17,367**	**16,152**	13,908	15,334
Long-term debt of joint ventures	**1,076**	**1,052**	903	937
Other long-term liabilities of joint ventures(4)	**–**	**–**	60	60
	23,691	**22,452**	18,262	19,722

(1) Consolidated Net Income in 2008 and 2007 included unrealized gains or losses of nil for the fair value adjustments to each of these financial instruments.

(2) At December 31, 2008, the Consolidated Balance Sheet included financial assets of $1,257 million (2007 – $1,018 million) in Accounts Receivable and $174 million (2007 – $230 million) in Other Assets.

(3) Recorded at amortized cost, except for certain Long-Term Debt which is adjusted to fair value.

(4) At December 31, 2008, the Consolidated Balance Sheet included financial liabilities of $1,342 million (2007 – $1,174 million) in Accounts Payable and $22 million (2007 – $78 million) in Deferred Amounts.

Derivative Financial Instruments Summary

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

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

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

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

(3) All power, natural gas and oil products realized and unrealized gains and losses are included in Revenues. All interest rate and foreign exchange realized and unrealized gains and losses are included in Financial Charges and Interest Income and Other, respectively. Realized gains and losses are included in Net Income upon settlement of the financial instrument.

(4) All hedging relationships are designated as cash flow hedges except for interest-rate derivative financial instruments designated as fair value hedges with a fair value of $8 million. In 2008, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

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

The anticipated timing of settlement of the derivative contracts assumes no changes in commodity prices, interest rates and foreign exchange rates from December 31, 2008. Actual settlements will vary based on changes in these factors. The anticipated timing of settlement of these contracts is as follows:

(millions of dollars)	Total	2009	2010 and 2011	2012 and 2013	2014 and Thereafter
Derivative financial instruments held for trading	(30)	38	(46)	(14)	(8)
Derivative financial instruments in hedging relationships	(199)	(68)	(65)	(43)	(23)
	(229)	(30)	(111)	(57)	(31)

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	–
Net unrealized gains/(losses) in the year(3)	$16	$(10)	$8	$(5)
Net realized (losses)/gains in the year(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	–
Net realized (losses)/gains in the year(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 power and natural gas realized and unrealized gains and losses are included in Revenues. All interest rate and foreign exchange realized and unrealized gains and losses are included in Financial Charges and Interest Income and Other, respectively. Realized gains and losses are included in Net Income upon settlement of the financial instrument.

(4) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $2 million. In 2007, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(5) In 2007, Net Income 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. In 2007, Net Income 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 when the anticipated transaction was not likely to occur by the end of the originally specified time period.

Balance Sheet Presentation of Derivative Financial Instruments

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

December 31 (millions of dollars)	**2008**	2007
Current		
Other current assets	**318**	160
Accounts payable	**(298)**	(144)
Long-term		
Other assets	**191**	204
Deferred amounts	**(694)**	(205)

OTHER RISKS

Development Projects and Acquisitions

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

Health, Safety and Environment Risk Management

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

TCPL is committed to ensuring compliance with its internal policies and regulated requirements. The HS&E Committee of TCPL's Board of Directors monitors compliance with the Company's HS&E corporate policy through regular reporting. TCPL's HS&E management system is modeled on the International Organization of Standardization's (ISO) standard for environmental management systems, ISO 14001, and focuses resources on the areas of significant risk to the organization's HS&E business activities. Management is informed regularly of all important HS&E operational issues and initiatives through formal reporting processes. TCPL's HS&E management system and performance are assessed by an independent outside firm every three years. The most recent assessment occurred in November 2006. The HS&E management system also is subject to ongoing internal review to ensure that it remains effective as circumstances change.

In 2008, employee and contractor health and safety performance continued to be a top priority. TCPL's assets were highly reliable and there were no incidents that were material to TCPL's operations.

The safety and integrity of the Company's pipelines is a top priority. The Company expects to spend approximately $185 million in 2009 for pipeline integrity on its wholly owned pipelines, which is higher than the amount spent in 2008 primarily due to increased levels of in-line pipeline inspection on all systems. Under the approved regulatory models in Canada, pipeline integrity expenditures on NEB- and AUC-regulated pipelines are treated on a flow-through basis and, as a result, have no impact on TCPL's earnings. Expenditures on the GTN System are also recovered through a cost recovery mechanism in its rates. Pipeline safety in 2008 continued to be very good, as TCPL experienced only one small-diameter pipeline failure in a remote part of east central Alberta. The break resulted in minimal impact with no injuries or property damage. Spending associated with public safety on the Energy assets is focused primarily on the Company's hydro dams and associated equipment, and is consistent with previous years.

Environment

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

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

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

In 2008, TCPL conducted environmental risk assessments and remediation work, resulting in total costs of approximately $7 million and US$6 million for work conducted on TCPL's Canadian and U.S. facilities, respectively. TCPL also conducted various retirement, reclamation and restoration work in 2008, which resulted in total costs of approximately $7 million. At December 31, 2008, TCPL had recorded liabilities of approximately $86 million for compliance and remediation obligations. The Company believes it has considered all necessary contingencies and established appropriate reserves for environmental liabilities, however, there is the risk that unforeseen matters may arise requiring the Company to set aside additional amounts.

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

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

In 2008, the Company owned assets in three regions affected by climate change policy measures related to industrial emissions. In Alberta, the Specified Gas Emitters Regulation, which came into effect in 2007, requires industrial facilities to reduce GHG emissions intensities by 12 per cent. TCPL's Alberta-based pipeline and power facilities are subject to this regulation, as are the Sundance and Sheerness coal-fired power facilities with which TCPL has commercial arrangements. The Company's total cost of compliance incurred by the Alberta-based facilities for the period from July 2007 to December 2007 was approximately $12 million. Costs for 2008 compliance are estimated to be $28 million and will be finalized when compliance reports are submitted in March 2009. Compliance costs of the Alberta System are recovered through tolls paid by customers. Recovery of compliance costs for the Company's power generation facilities and interests in Alberta is partially achieved through contracts and the impact of increased operating costs on Alberta power market prices.

The hydrocarbon royalty in Québec is collected by the natural gas distributor on behalf of the Québec government via a green fund contribution charge on gas consumed. In 2008, the cost pertaining to the Bécancour facility arising from the hydrocarbon royalty was less than $1 million as a result of an agreement between TCPL and Hydro-Québec to temporarily suspend the facility's power generation. The cost is expected to increase when the plant returns to service in 2010.

B.C.'s carbon tax, which came into effect in mid-2008, applies to carbon dioxide (CO_2) emissions arising from fossil fuel combustion. Compliance costs for fuel combustion at the Company's compressor and meter stations in B.C. are recovered through tolls paid by customers. Costs related to the carbon tax for 2008 were $1 million. This cost is expected to increase over the next four years as the tax charge per tonne of CO_2 increases by $5 per tonne annually from the initial tax rate of $10 per tonne.

TCPL has assets located in Ontario and Manitoba, where the provincial governments have announced climate change strategies that will impact industrial sources of GHG emissions. The details of these programs and how they will align with the Canadian government's climate change policies are still uncertain.

The Canadian government has expressed interest in pursuing the development of a North American cap and trade system for GHG emissions. In April 2007, the Government of Canada released the Regulatory Framework for Air Emissions (Framework). The Framework outlines short-, medium- and long-term objectives for managing both GHG emissions and air pollutants in Canada. TCPL 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 not known at this time whether the impacts from the pending regulations will be material as the draft regulations have not yet been released. It is uncertain how the Framework will fit within a North American cap and trade system and what the specific requirements for industrial emitters will be.

Climate change is a strategic issue for the new U.S. government administration and federal policy to manage domestic GHG emissions is expected to be a priority. Seven western states and four Canadian provinces are focused on the implementation of a cap and trade program under the Western Climate Initiative (WCI). Northeastern states that are members of the Regional Greenhouse Gas Initiative (RGGI) implemented a CO_2 cap and trade program for electricity generators effective January 1, 2009. Participants in the Midwestern Greenhouse Gas Reduction Accord, which involves six states and one province, are developing a regional strategy for reducing members' GHG emissions that will include a multi-sector cap and trade mechanism.

The Company anticipates a number of its facilities will be affected by these legislative initiatives. Under the RGGI, both the Ravenswood and OSP facilities will be required to submit allowances by December 31, 2011. It is expected that the costs will be recovered from the market and the net impact to TCPL will be minimal. Company assets located in regions affected by the WCI and Midwestern Greenhouse Gas Reduction Accord and in California are most likely to be covered by GHG reduction measures put in place, however, the level of impact is uncertain as key policy details remain outstanding.

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

CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

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

As at December 31, 2008, an evaluation of the effectiveness of TCPL's disclosure controls and procedures as defined under the rules adopted by the Canadian securities regulatory authorities and by the SEC was carried out under the supervision and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer. Based on this evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that the design and operation of TCPL's disclosure controls and procedures were effective as at December 31, 2008.

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. The Company acquired Ravenswood in August 2008 and began consolidating the operations of Ravenswood from that date. Management has excluded this business from its evaluation of the effectiveness of the Company's internal control over financial reporting as of December 31, 2008. The net income attributable to this business represented less than one per cent of the Company's consolidated net income for the year ended December 31, 2008, and its aggregate total assets represented approximately nine per cent of the Company's consolidated total assets as at December 31, 2008.

Based on this evaluation, management concluded that internal control over financial reporting is effective as at December 31, 2008, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

In 2008, there was no change in TCPL's internal control over financial reporting that materially affected or is reasonably likely to materially affect TCPL's internal control over financial reporting.

CEO and CFO Certifications
TCPL'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 TCPL's public disclosures relating to its fiscal 2008 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, TCPL 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. The Company believes the following accounting policies and estimates require it to make assumptions about highly uncertain matters and changes in these estimates could have a material impact to the Company's financial information.

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

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

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

Financial Instruments and Hedges

Financial Instruments
Effective January 1, 2007, the Company adopted the accounting requirements for the Canadian Institute of Chartered Accountants (CICA) Handbook Sections 1530 "Comprehensive Income", 3855 "Financial Instruments – Recognition and Measurement", and 3865 "Hedges". Effective December 31, 2007, the Company adopted the accounting requirements for CICA Handbook Sections 3862 "Financial Instruments – Disclosure", 3863 "Financial Instruments – Presentation", and 1535 "Capital Disclosures". Adjustments to the consolidated financial statements for 2007 were made on a prospective basis.

The CICA Handbook requires that all financial instruments 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. The Company does not have any held-to-maturity investments.

Held-for-trading derivative financial assets and liabilities consist of swaps, options, forwards and futures. Commodity held-for-trading financial instruments are initially recorded at their fair value and changes to fair value are included in

Revenues. Changes in the fair value of interest rate and foreign exchange rate held-for-trading instruments are recorded in Financial Charges and in Interest Income and Other, respectively.

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

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

Hedges

The CICA Handbook 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 hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

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

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

The Company also enters into cash flow hedges and fair value hedges for activities subject to rate regulation. 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 reclassified to Net Income in the event the Company settles or otherwise reduces its investment in a foreign operation.

The fair value of financial instruments and hedges is primarily derived from market values adjusted for credit risk, which can fluctuate greatly from period to period. These changes in fair value can result in variability in net income as a result of recording these changes in fair value through earnings. The risks associated with fluctuations to earnings and cash flows for financial instruments and hedges are discussed further in the "Risk Management and Financial Instruments" section of this MD&A.

Depreciation and Amortization Expense

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

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

Impairment of Long-Lived Assets and Goodwill

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

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

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

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

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

ACCOUNTING CHANGES

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, was withdrawn. In addition, Section 3465 "Income Taxes" was amended to require the recognition of future income tax assets and liabilities for rate-regulated entities. The Company has chosen to adopt accounting policies consistent with the U.S. Financial Accounting Standards Board's Financial Accounting Standard (FAS) 71 "Accounting for the Effects of Certain Types of Regulation". Accordingly, TCPL will retain its current method of accounting for its rate-regulated operations, except that TCPL will be required to recognize future income tax assets and liabilities instead of using the taxes payable method, and will record an offsetting adjustment to regulatory assets and liabilities. If the Company had adopted FAS 71 at December 31, 2008, additional future income tax liabilities and a regulatory asset in the amount of $1,434 million would have been recorded and would have been recoverable from future revenue. These changes will be applied retrospectively without restatement beginning January 1, 2009.

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 International Financial Reporting Standards (IFRS) and U.S. GAAP. CICA Handbook 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 International Accounting Standards Board's (IASB) "Framework for the Preparation and Presentation of Financial Statements" that helps distinguish assets from expenses. CICA Handbook Section 3064 "Goodwill and Intangible Assets", which replaced CICA Handbook 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. In addition, CICA Handbook 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.

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

International Financial Reporting Standards
The CICA's Accounting Standards Board announced that Canadian publicly accountable enterprises are required to adopt IFRS, as issued by the IASB, effective January 1, 2011. In June 2008, the Canadian Securities Administrators proposed that Canadian public companies that are SEC registrants, such as TCPL, retain the option to prepare their financial statements under U.S. GAAP instead of IFRS. In November 2008, the SEC issued for public comment a recommendation that, beginning in 2014, U.S. issuers be required to adopt IFRS using a phased-in approach based on market capitalization.

TCPL is currently considering the impact a conversion to IFRS or U.S. GAAP would have on its accounting systems and financial statements. TCPL's conversion project planning includes an analysis of project structure and governance, resources and training, analysis of key GAAP differences and a phased approach to the assessment of current accounting policies and implementation. The current status of the key elements of TCPL's conversion project is as follows:

Project Structure and Governance

A Steering Committee and an Implementation Committee have been established to provide directional leadership for the conversion project and to assist in developing accounting policy recommendations. These are multi-disciplinary committees and include representatives from Accounting, Information Technology, Treasury, Investor Relations, Human Resources and Operations. Management updates the Audit Committee at least quarterly on the status of the project.

Resources and Training

TCPL's conversion project team has been assembled and will support the conversion effort through project leadership, training, issue identification, technical research, policy recommendations, work group leadership and implementation support.

TCPL's IFRS training plan was developed and introduced in 2008. The first stage of the training has been completed and included IFRS project awareness sessions and a comprehensive IFRS immersion course. Later phases of the project will include more directed technical and implementation training relating to new accounting policies, procedures and processes. Throughout the project, IFRS training will be offered on a regular basis to ensure that TCPL staff remains current with respect to new IFRS developments.

Analysis of Significant GAAP Differences

The project team is currently assessing the differences between Canadian GAAP and IFRS. TCPL's conversion project is being executed using a risk-based methodology focusing on the significant differences between Canadian GAAP and IFRS. A high-level diagnostic was completed in 2008 outlining the significant differences and rating each option based on its significance to TCPL. In making this assessment, the technical accounting complexity, availability of policy choices, estimated need for conversion resources and impact on systems were considered. The differences between Canadian and US GAAP have already been identified in the Company's U.S. GAAP reconciliation. The most significant differences under the IFRS and U.S. GAAP conversion options were identified as follows:

IFRS

Converting to IFRS would have a significant impact on TCPL's rate-regulated operations, property plant and equipment, employee benefits, income taxes, financial statement disclosure and the initial adoption of IFRS in accordance with IFRS 1 "First-Time Adoption of IFRS".

Project work groups are currently conducting a detailed analysis of the significant differences identified to date and assessing the impact they could have on TCPL's financial reporting, information systems and internal controls over financial reporting. Less significant differences will be assessed starting in 2009. Under existing Canadian GAAP, TCPL follows specific accounting policies unique to rate-regulated businesses. TCPL is actively monitoring ongoing discussions and developments at the IASB regarding potential future guidance to clarify the applicability of certain aspects of rate-regulated accounting under IFRS. The IASB is expected to issue a proposed standard for rate-regulated businesses in 2009.

Several IFRS standards are in the process of being amended by the IASB. Amendments to existing standards are expected to continue until the transition date of January 1, 2011. TCPL actively monitors the IASB's schedule of projects, giving consideration to any proposed changes, where applicable, in its assessment of differences between IFRS and Canadian GAAP.

At the current stage of the project, TCPL cannot reasonably determine the full impact that adopting IFRS would have on its financial position and future results. In addition, developments with respect to specific rate-regulated accounting guidance under IFRS could have a significant effect on the scope of the project and on TCPL's financial results.

U.S. GAAP

As an SEC registrant, TCPL is currently required to prepare and file a reconciliation from Canadian GAAP to U.S. GAAP. The differences that have the most significant impact on TCPL, as outlined in the reconciliation, include valuation of proprietary natural gas inventory held in storage, measurement of the deficit or surplus of defined benefit pension plans and recognition of deferred tax liabilities for TCPL's rate-regulated business. As previously noted, effective January 1, 2009, the U.S. GAAP difference with respect to recognition of deferred tax liabilities for TCPL's rate-regulated businesses will be eliminated.

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA[1]

(unaudited)	**2008**			
(millions of dollars except per share amounts)	**Fourth**	**Third**	**Second**	**First**
Revenues	**2,332**	**2,137**	**2,017**	**2,133**
Net Income Applicable to Common Shares	**274**	**383**	**318**	**445**
Share Statistics				
Net income per common share – Basic and Diluted	**$0.47**	**$0.70**	**$0.60**	**$0.84**

(unaudited)	2007			
(millions of dollars except per share amounts)	Fourth	Third	Second	First
Revenues	2,189	2,187	2,208	2,244
Net Income Applicable to Common Shares	373	320	254	263
Share Statistics				
Net income per common share – Basic and Diluted	$0.71	$0.61	$0.49	$0.52

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

Factors Impacting Quarterly Financial Information

In Pipelines, which consists primarily of the Company's investments in regulated pipelines and regulated natural gas storage facilities, annual revenues and net 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 2008 and 2007 were as follows:

- ***Fourth quarter 2008***, Energy's net earnings included net unrealized gains of $6 million after tax ($7 million pre-tax) due to changes in fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts. Corporate's net expenses included net unrealized losses of $39 million after tax ($57 million pre-tax) for changes in the fair value of derivatives, which are used to manage the Company's exposure to rising interest rates but do not qualify as hedges for accounting purposes.

- ***Third quarter 2008***, Energy's net earnings included contributions from the August 26, 2008 acquisition of Ravenswood. Corporate's net earnings included favourable income tax adjustments of $26 million from an internal restructuring and realization of losses.
- ***Second quarter 2008***, Energy's net earnings included net unrealized gains of $8 million after tax ($12 million pre-tax) due to changes in fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts. In addition, Western Power's revenues and operating income increased due to higher overall realized prices and market heat rates in Alberta.
- ***First quarter 2008***, Pipelines' net earnings included $152 million after tax ($240 million pre-tax) from the Calpine bankruptcy settlements received by GTN and Portland, and proceeds of $10 million after tax ($17 million pre-tax) from a lawsuit settlement. Energy's net earnings included a writedown of $27 million after tax ($41 million pre-tax) of costs related to Broadwater and net unrealized losses of $12 million after tax ($17 million pre-tax) due to changes in the fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts.
- ***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. Energy's net earnings included net unrealized gains of $10 million after tax ($15 million pre-tax) due to changes in fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts.
- ***Third quarter 2007***, net earnings included $15 million of favourable income tax reassessments and associated interest income relating to prior years.
- ***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.
- ***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 additional ownership interests in Great Lakes. Energy's net earnings included earnings from the Edson natural gas facility, which was placed in service on December 31, 2006.

FOURTH QUARTER 2008 HIGHLIGHTS

CONSOLIDATED RESULTS OF OPERATIONS
Reconciliation of Comparable Earnings to Net Income Applicable to Common Shares

(unaudited) *(millions of dollars)*	**2008**	2007
Pipelines	**210**	202
Energy		
Comparable earnings[1]	**147**	104
Specific items (net of tax, where applicable):		
Fair value adjustments of natural gas storage inventory and forward contracts	**6**	10
Gain on sale of land	**–**	14
Income tax adjustments	**–**	30
Net income	**153**	158
Corporate		
Comparable expenses[1]	**(89)**	(13)
Specific item:		
Income tax reassessments and adjustments	**–**	26
Net (expenses)/income	**(89)**	13
Net Income Applicable to Common Shares	**274**	373
Comparable Earnings[1]	**268**	293
Specific items (net of tax, where applicable):		
Fair value adjustments of natural gas storage inventory and forward contracts	**6**	10
Gain on sale of land	**–**	14
Income tax reassessments and adjustments	**–**	56
Net Income Applicable to Common Shares	**274**	373

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

TCPL's net income applicable to common shares in fourth quarter 2008 was $274 million compared to $373 million in fourth quarter 2007. Net income applicable to common shares decreased primarily due to increased net expenses from Corporate, which included unrealized losses of $39 million after tax in fourth quarter 2008, for changes in the fair value of derivatives, which are used to manage the Company's exposure to rising interest rates but do not qualify as hedges for accounting purposes. Corporate's net expenses also increased in fourth quarter 2008 compared to fourth quarter 2007 as a result of higher charges for financing the Company's 2008 capital program, including the Ravenswood acquisition, and higher unrealized gains in 2007 for changes in the fair value of derivatives used to manage the Company's exposure to foreign exchange rate fluctuations. Earnings from the Pipelines business increased in fourth quarter 2008 compared to fourth quarter 2007 primarily due to earnings recognized from a 2008 revenue requirement settlement for the Alberta System and increased earnings for PipeLines LP, partially offset by the inclusion in earnings in fourth quarter 2007 for a rate case settlement for GTN. Earnings from the Energy business were slightly lower in fourth quarter 2008 compared to fourth quarter 2007 as increases in Western Power, Eastern Power and Bruce Power were more than offset by a decrease in earnings from Natural Gas Storage in 2008 and favourable income tax adjustments that were included in fourth quarter 2007. Western Power earnings increased significantly in fourth quarter 2008 compared to fourth quarter 2007 primarily due to increased margins from the Alberta power portfolio. Energy's earnings in fourth quarter 2008 and 2007 included $6 million after tax ($7 million pre-tax) and $10 million after tax ($15 million pre-tax), respectively, of net unrealized gains resulting from changes in the fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts. Energy's earnings in fourth quarter 2007 also included a $14 million after-tax ($16 million pre-tax) gain on the sale of land. Net income for fourth quarter 2007 included $56 million ($30 million in Energy and $26 million in Corporate) of favourable income tax adjustments as a result of changes in Canadian federal income tax legislation.

Comparable earnings in fourth quarter 2008 were $268 million compared to $293 million for the same period in 2007. Comparable earnings in fourth quarter 2008 and 2007 excluded the $6 million and $10 million, respectively, of net unrealized gains resulting from changes in fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts. Comparable earnings in fourth quarter 2007 also excluded the $56 million of favourable income tax adjustments and $14 million gain on the sale of land.

The Pipelines business generated net income and comparable earnings of $210 million in fourth quarter 2008, an increase of $8 million compared to net income and comparable earnings of $202 million in fourth quarter 2007.

Canadian Mainline's net income for fourth quarter 2008 increased $2 million, compared to the same period in 2007 primarily due to higher performance-based incentives earned, increased OM&A cost savings and a higher ROE, as determined by the NEB, of 8.71 per cent in 2008 compared to 8.46 per cent in 2007. These increases were partially offset by a lower average investment base.

The Alberta System's net income in fourth quarter 2008 was $48 million compared to $41 million in fourth quarter 2007. Earnings increased primarily due to the recognition of earnings related to the revenue requirement settlement in fourth quarter 2008. Earnings in 2007 reflected an approved ROE of 8.51 per cent on a deemed common equity of 35 per cent.

ANR's net income in fourth quarter 2008 was $38 million compared to $35 million in fourth quarter 2007. The increase in fourth quarter 2008 was primarily due to higher revenues from new growth projects and the positive impact of a stronger U.S. dollar. These increases were partially offset by higher OM&A costs, including Hurricane Ike remediation costs.

GTN's comparable earnings in fourth quarter 2008 decreased $16 million compared to the same period in 2007. The decrease was primarily due to the positive impact of the rate case settlement included in fourth quarter 2007, partially offset by decreased OM&A expenses.

TCPL's proportionate share of net income from Other Pipelines was $29 million for the three months ended December 31, 2008 compared to $16 million for the same period in 2007. Other Pipelines' earnings increased in fourth quarter 2008 primarily due to lower support costs, higher PipeLines LP and Tamazunchale earnings, and a stronger U.S. dollar, partially offset by lower TransGas, Gas Pacifico/INNERGY and Portland earnings.

Energy's net income of $153 million in fourth quarter 2008 decreased $5 million compared to $158 million in fourth quarter 2007. Comparable earnings in fourth quarter 2008 of $147 million increased $43 million compared to $104 million for the same period in 2007. Comparable earnings excluded the net unrealized gains of $6 million after tax and $10 million after tax in fourth quarter 2008 and 2007, respectively, resulting from changes in fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts. In addition, comparable earnings in fourth quarter 2007 excluded the $14 million gain on sale of land and $30 million of favourable income tax adjustments.

Western Power's operating income of $106 million in fourth quarter 2008 increased $48 million compared to $58 million in fourth quarter 2007 primarily due to increased margins from the Alberta power portfolio, which resulted from higher overall realized power prices and market heat rates on both contracted and uncontracted volumes of power sold in Alberta. The market heat rate is determined by dividing the average price of power per MWh by the average price of natural gas per GJ for a given period.

Eastern Power's operating income of $73 million in fourth quarter 2008 increased $7 million compared to $66 million in fourth quarter 2007. The increase was due to higher realized prices on sales to commercial and industrial customers in New England, the positive impact of the stronger U.S. dollar in fourth quarter 2008 and incremental earnings from the Carleton wind farm, which went into service in November 2008. On December 31, 2008, Ravenswood fulfilled its obligation under a tolling agreement with Hess Corporation that was in place at the time of acquisition. In 2009, TCPL's marketing operation will manage marketing of the Ravenswood plant output in a manner consistent with its other U.S. Northeast portfolio of assets.

TCPL's combined operating income of $50 million from its investment in Bruce Power increased $7 million in fourth quarter 2008 compared to fourth quarter 2007 primarily due to higher revenues resulting from higher realized prices. TCPL's proportionate share of operating loss in Bruce A increased $1 million to $6 million in fourth quarter 2008 compared to fourth quarter 2007 as a result of lower revenues due to decreased output, partially offset by higher contract prices and lower operating costs. TCPL's proportionate share of operating income in Bruce B increased $8 million to $61 million in fourth quarter 2008 compared to fourth quarter 2007 primarily due to higher realized prices achieved during fourth quarter 2008, as well as increased output. The increase in realized prices was due to higher contract prices on a larger proportion of volumes sold under contract in the three months ended December 31, 2008 compared to the same period in 2007.

Natural Gas Storage operating income of $40 million in fourth quarter 2008 decreased $17 million compared to $57 million in fourth quarter 2007. The decrease was due to lower realized seasonal natural gas price spreads at the Edson facility compared to the same period in 2007. Operating income in fourth quarter 2008 included net unrealized gains of $7 million for changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts compared to net unrealized gains of $15 million for the same period in 2007.

Corporate's net expenses for the three months ended December 31, 2008 were $89 million compared to net income of $13 million for the same period in 2007. Excluding the $26 million of favourable income tax adjustments in fourth quarter 2007, Corporate's comparable expenses increased $76 million in fourth quarter 2008 compared to fourth quarter 2007. The increase in comparable expenses in fourth quarter 2008 was primarily due to net unrealized losses of $39 million after tax from changes in the fair value of derivatives, which are used to manage the Company's exposure to rising interest rates but do not qualify as hedges for accounting purposes. In addition, higher financial charges resulting from financing the Ravenswood acquisition and higher losses from the change in fair value of derivatives used to manage the Company's exposure to foreign exchange rate fluctuations were partially offset by increased capitalization of interest to finance a larger capital spending program.

SHARE INFORMATION

At February 23, 2009, TCPL had 600 million issued and outstanding common shares and there were no outstanding options to purchase common shares.

OTHER INFORMATION

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

Other selected consolidated financial information for 2000 to 2008 is found under the heading "Nine Year Financial Highlights" in the Supplementary Information section of the Company's Annual Report.

GLOSSARY OF TERMS

AFUDC	Allowance for funds used during construction
AGIA	Alaska Gasline Inducement Act
Alaska Pipeline Project	A proposed natural gas pipeline extending from a new natural gas treatment plant at Prudhoe Bay, Alaska to Alberta
Alberta System	A natural gas transmission system in Alberta
American Natural Resources (ANR)	A natural gas transmission system extending from producing fields located primarily in Oklahoma, Texas, Louisiana and the Gulf of Mexico to markets located primarily in Wisconsin, Michigan, Illinois, Ohio and Indiana, and regulated underground natural gas storage facilities in Michigan
ANR Pipeline	ANR Pipeline Company
APG	Aboriginal Pipeline Group
AUC	Alberta Utilities Commission
B.C.	British Columbia
Bbl/d	Barrels per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
Bear Creek	A natural gas-fired cogeneration plant near Grande Prairie, Alberta
Bécancour	A natural gas-fired cogeneration plant near Trois-Rivières, Québec
Bison	A proposed pipeline from the Powder River Basin in Wyoming to the Northern Border system in North Dakota
BPC	BPC Generation Infrastructure Trust
Broadwater	A proposed offshore LNG project located in the New York waters of Long Island Sound
Bruce A	A partnership interest in the nuclear power generation facilities of Bruce Power A L.P.
Bruce B	A partnership interest in the nuclear power generation facilities of Bruce Power L.P
Bruce Power	Bruce A and Bruce B, collectively
Calpine	Calpine Corporation
Cameco	Cameco Corporation
Canadian Mainline	A natural gas transmission system extending from the Alberta/Saskatchewan border east into Québec
Cancarb	A waste-heat fuelled power plant at the Cancarb thermal carbon black facility in Medicine Hat, Alberta
CAPLA	Canadian Alliance of Pipeline Landowners' Associations
Carseland	A natural gas-fired cogeneration plant located near Carseland, Alberta
Cartier Wind	Six wind farms in Gaspé, Québec, three of which have been built
Chinook	A proposed HVDC transmission project that will originate in Montana and terminate in Nevada
CICA	Canadian Institute of Chartered Accountants
CO_2	Carbon dioxide
Coolidge	A simple-cycle, natural gas-fired peaking power generation station under development in Coolidge, Arizona
CrossAlta	An underground natural gas storage facility near Crossfield, Alberta
DRP	Dividend Reinvestment and Share Purchase Plan
Edson	A natural gas storage facility near Edson, Alberta
FAS	Financial Accounting Standard
FCM	Forward Capacity Market
FERC	U.S. Federal Energy Regulatory Commission
Foothills	A natural gas transmission system extending from central Alberta to the B.C./U.S. border and to the Saskatchewan/U.S. border
Framework	Regulatory Framework for Air Emissions
GAAP	Generally accepted accounting principles
Gas Pacifico	A natural gas transmission system extending from Loma de la Lata, Argentina to Concepción, Chile
GHG	Greenhouse gas
GJ	Gigajoule
Grandview	A natural gas-fired cogeneration plant near Saint John, New Brunswick
Great Lakes	A natural gas transmission system that connects to the Canadian Mainline and serves markets in Eastern Canada and the northeastern and midwestern U.S.
Gas Transmission Network (GTN)	GTN System and North Baja, collectively
GTNC	Gas Transmission Northwest Corporation

GTN System	A natural gas transmission system extending from the B.C./Idaho border to the Oregon/California border, traversing Idaho, Washington and Oregon
GWh	Gigawatt hours
Halton Hills	A natural gas-fired, combined-cycle power plant near Toronto, Ontario
HS&E	Health, Safety and Environment
HVDC	High voltage direct current
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
INNERGY	An industrial natural gas marketing company based in Concepción, Chile
Iroquois	A natural gas transmission system that connects with the Canadian Mainline near Waddington, New York, and delivers natural gas to the northeastern U.S.
ISO	International Organization of Standardization
ISO-NE	Independent System Operator New England
Keystone	A pipeline under construction that will transport crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, and to Cushing, Oklahoma
Keystone partnerships	TransCanada Keystone Pipeline Limited Partnership and TransCanada Keystone Pipeline, LP, collectively
Kibby Wind	A wind power project located in Kibby and Skinner Townships in northwestern Franklin County, Maine
km	Kilometres
kV	Kilovolt
LIBOR	London Interbank Offered Rate
LNG	Liquefied natural gas
MacKay River	A natural gas-fired cogeneration plant located near Fort McMurray, Alberta
MD&A	Management's Discussion and Analysis
Mackenzie Gas Pipeline (MGP)	A proposed natural gas pipeline to be constructed from a point near Inuvik, Northwest Territories to the northern border of Alberta
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 of Canada
Net earnings	Net income from continuing operations
North Baja	A natural gas transmission system extending from Arizona to the Baja California, Mexico/California border
Northern Border	A natural gas transmission system extending from a point near Monchy, Saskatchewan, to the U.S. Midwest
NorthernLights	A proposed HVDC electric transmission line running from central Alberta to a terminal in southern Alberta and interconnecting with the Pacific Northwest
NYISO	New York Independent System Operator
OM&A	Operating, maintenance and administration
OPA	Ontario Power Authority
Ocean State Power (OSP)	A natural gas-fired, combined-cycle plant in Burrillville, Rhode Island
Palomar	A proposed pipeline extending from the GTN System to the Columbia River northwest of Portland
Pathfinder	A proposed pipeline from Meeker, Colorado to the Northern Border system in North Dakota
PipeLines LP	TC PipeLines, LP
PNGTS	Portland Natural Gas Transmission System
Portland	A natural gas transmission system that extends from a point near East Hereford, Québec to the northeastern U.S.
Portlands Energy	A combined-cycle natural gas cogeneration plant near downtown Toronto, Ontario
PPA	Power purchase arrangement
Ravenswood	A natural gas and oil-fired generating facility consisting of multiple units employing steam turbine, combined cycle and combustion turbine technology located in Queens, New York
Redwater	A natural gas-fired cogeneration plant located near Redwater, Alberta
RGGI	Regional Greenhouse Gas Initiative
ROE	Rate of return on common equity
Salt River Project	Salt River Project Agricultural Improvement and Power District

SEC	U.S. Securities and Exchange Commission
Sempra	Sempra Pipelines and Storage
Sheerness	A coal-fired power generating facility located near Hanna, Alberta
STEP 2008	Storage enhancement project
Sundance A	A coal-fired power generating facility located near Wabamun, Alberta
Sundance B	A coal-fired power generating facility located near Wabamun, Alberta
Sunstone	A proposed pipeline from Wyoming to Stanfield, Oregon
Tamazunchale	A natural gas transmission system in Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi
TC Hydro	Hydroelectric generation assets located in New Hampshire, Vermont and Massachusetts
TCPL or the Company	TransCanada PipeLines Limited
TCPM	TransCanada Power Marketing Ltd.
Trans Québec & Maritimes (TQM)	A natural gas transmission system that connects with the Canadian Mainline and transports natural gas in Québec, from Montreal to the Portland system and to Québec City
TransCanada	TransCanada Corporation
TransGas	A natural gas transmission system, extending from Mariquita in the central region of Colombia to Cali in the southwest region of Colombia
Tuscarora	A natural gas transmission system extending from Malin, Oregon to Wadsworth, Nevada
U.S.	United States
VaR	Value-at-Risk methodology
Ventures LP	Natural gas transmission systems in Alberta that supply natural gas to the oil sands region of northern Alberta and to a petrochemical complex at Joffre, Alberta
WCI	Western Climate Initiative
WCSB	Western Canada Sedimentary Basin
Williams	Williams Gas Pipeline Company, LLC
Zephyr	A proposed HVDC transmission project that will originate in Wyoming and terminate in Nevada

Report of Management

The consolidated financial statements included in this Annual Report are the responsibility of TransCanada PipeLines Limited's (TCPL or the Company) 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 judgements. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management's Discussion and Analysis in this Annual Report has been prepared by management based on the Company's financial results prepared in accordance with Canadian GAAP. It compares the Company's financial and operating performance in 2008 to that in 2007 and should be read in conjunction with the consolidated financial statements and accompanying notes. In addition, it highlights significant changes between 2007 and 2006.

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 the 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 of, 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. TCPL acquired the Ravenswood Generating Station (Ravenswood) in 2008 and began consolidating the operations of Ravenswood from the date of acquisition. Management has excluded this business from its evaluation of the effectiveness of the Company's internal control over financial reporting as of December 31, 2008. The net income attributable to this business represented less than one per cent of the Company's consolidated net income for the year ended December 31, 2008 and its aggregate total assets represented approximately nine per cent of the Company's consolidated total assets as at December 31, 2008.

Based on their evaluation, management concluded that internal control over financial reporting is effective as of December 31, 2008 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

The Board of Directors has appointed an Audit Committee consisting of independent, non-management directors. The Audit Committee meets with management at least six times a year and meets independently with the internal and external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form. The Audit Committee 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 independent external auditors are able to access the Audit Committee without the requirement to obtain prior management approval.

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

The shareholders have appointed KPMG LLP as independent external auditors to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's consolidated financial position, results of operations and cash flows in accordance with 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 23, 2009

Auditors' Report

To the Shareholders of TransCanada PipeLines Limited

We have audited the consolidated balance sheets of TransCanada PipeLines Limited as at December 31, 2008 and 2007 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, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2008 and 2007 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2008 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada

February 23, 2009

TRANSCANADA PIPELINES LIMITED
CONSOLIDATED INCOME

Year ended December 31 *(millions of dollars)*	**2008**	2007	2006
Revenues	**8,619**	8,828	7,520
Operating Expenses			
Plant operating costs and other	**3,062**	3,030	2,411
Commodity purchases resold	**1,511**	1,959	1,707
Depreciation	**1,189**	1,179	1,059
	5,762	6,168	5,177
	2,857	2,660	2,343
Other Expenses/(Income)			
Financial charges (Note 10)	**962**	961	828
Financial charges of joint ventures (Note 11)	**72**	75	92
Interest income and other	**(80)**	(166)	(179)
Calpine bankruptcy settlements (Note 18)	**(279)**	–	–
Writedown of Broadwater LNG project costs (Note 7)	**41**	–	–
	716	870	741
Income from Continuing Operations before Income Taxes and Non-Controlling Interests	**2,141**	1,790	1,602
Income Taxes (Note 19)			
Current	**524**	429	300
Future	**67**	54	175
	591	483	475
Non-Controlling Interests (Note 15)	**108**	75	56
Net Income from Continuing Operations	**1,442**	1,232	1,071
Net Income from Discontinued Operations (Note 26)	**–**	–	28
Net Income	**1,442**	1,232	1,099
Preferred Share Dividends	**22**	22	22
Net Income Applicable to Common Shares	**1,420**	1,210	1,077
Net Income Applicable to Common Shares			
Continuing operations	**1,420**	1,210	1,049
Discontinued operations	**–**	–	28
	1,420	1,210	1,077

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

TRANSCANADA PIPELINES LIMITED
CONSOLIDATED CASH FLOWS

Year ended December 31 *(millions of dollars)*	**2008**	2007	2006
Cash Generated from Operations			
Net income	**1,442**	1,232	1,099
Depreciation	**1,189**	1,179	1,059
Future income taxes (Note 19)	**67**	54	175
Non-controlling interests (Note 15)	**108**	75	56
Employee future benefits funding lower than/(in excess of) expense (Note 22)	**17**	43	(31)
Writedown of Broadwater LNG project costs (Note 7)	**41**	–	–
Other	**128**	20	16
	2,992	2,603	2,374
(Increase)/decrease in operating working capital (Note 23)	**(188)**	215	(300)
Net cash provided by operations	**2,804**	2,818	2,074
Investing Activities			
Capital expenditures	**(3,134)**	(1,651)	(1,572)
Acquisitions, net of cash acquired (Note 9)	**(3,229)**	(4,223)	(470)
Disposition of assets, net of current income taxes (Note 9)	**28**	35	23
Deferred amounts and other	**(143)**	(321)	(95)
Net cash used in investing activities	**(6,478)**	(6,160)	(2,114)
Financing Activities			
Dividends on common and preferred shares (Note 16 and 17)	**(817)**	(725)	(639)
Distributions paid to non-controlling interests	**(119)**	(66)	(50)
Advances (to)/from parent (Note 25)	**(180)**	389	40
Notes payable issued/(repaid), net (Note 20)	**1,659**	(412)	(495)
Long-term debt issued, net of issue costs (Note 10)	**2,197**	2,616	2,107
Reduction of long-term debt	**(840)**	(1,088)	(729)
Long-term debt of joint ventures issued (Note 11)	**173**	142	56
Reduction of long-term debt of joint ventures	**(120)**	(157)	(70)
Common shares issued (Note 17)	**2,419**	1,842	–
Junior subordinated notes issued, net of issue costs (Note 12)	**–**	1,094	–
Preferred securities redeemed	**–**	(488)	–
Partnership units of subsidiary issued (Note 9)	**–**	348	–
Net cash provided by financing activities	**4,372**	3,495	220
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**98**	(50)	9
Increase in Cash and Cash Equivalents	**796**	103	189
Cash and Cash Equivalents			
Beginning of year	**504**	401	212
Cash and Cash Equivalents			
End of year	**1,300**	504	401

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

TRANSCANADA PIPELINES LIMITED
CONSOLIDATED BALANCE SHEET

December 31 *(millions of dollars)*	**2008**	2007
ASSETS		
Current Assets		
Cash and cash equivalents	**1,300**	504
Accounts receivable	**1,280**	1,116
Due from TransCanada Corporation (Note 25)	**1,529**	1,407
Inventories	**489**	497
Other	**523**	188
	5,121	3,712
Plant, Property and Equipment (Note 5)	**29,189**	23,452
Goodwill (Note 6)	**4,397**	2,633
Other Assets (Note 7)	**2,228**	1,940
	40,935	31,737
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable (Note 20)	**1,702**	55
Accounts payable	**1,868**	1,764
Due to TransCanada Corporation (Note 25)	**1,821**	572
Accrued interest	**361**	265
Current portion of long-term debt (Note 10)	**786**	556
Current portion of long-term debt of joint ventures (Note 11)	**207**	30
	6,745	3,242
Due to TransCanada Corporation (Note 25)	**–**	1,307
Deferred Amounts (Note 13)	**1,719**	1,107
Future Income Taxes (Note 19)	**1,253**	1,193
Long-Term Debt (Note 10)	**15,368**	12,377
Long-Term Debt of Joint Ventures (Note 11)	**869**	873
Junior Subordinated Notes (Note 12)	**1,213**	975
	27,167	21,074
Non-Controlling Interests (Note 15)	**805**	610
Shareholders' Equity	**12,963**	10,053
	40,935	31,737

Commitments, Contingencies and Guarantees (Note 24)

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 PIPELINES LIMITED
CONSOLIDATED COMPREHENSIVE INCOME

Year ended December 31 *(millions of dollars)*	**2008**	2007	2006
Net Income	**1,442**	1,232	1,099
Change in foreign currency translation gains and losses on investments in foreign operations[(1)]	**571**	(350)	6
Change in gains and losses on hedges of investments in foreign operations[(2)]	**(589)**	79	(6)
Change in gains and losses on derivative instruments designated as cash flow hedges[(3)]	**(60)**	42	–
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[(4)]	**(23)**	42	–
Change in gains and losses on available-for-sale financial instruments[(5)]	**2**	–	–
Other Comprehensive Income/(Loss)	**(99)**	(187)	–
Comprehensive Income	**1,343**	1,045	1,099

(1) Net of income tax recovery of $104 million in 2008 (2007 – $101 million expense; 2006 – $3 million expense).

(2) Net of income tax recovery of $303 million in 2008 (2007 – $41 million expense; 2006 – $3 million recovery).

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

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

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

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

TRANSCANADA PIPELINES LIMITED
CONSOLIDATED ACCUMULATED OTHER COMPREHENSIVE INCOME

(millions of dollars)	Currency Translation Adjustment	Cash Flow Hedges and Other	Total
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)
Change in foreign currency translation gains and losses on investments in foreign operations(1)	**571**	**–**	**571**
Change in gains and losses on hedges of investments in foreign operations(2)	**(589)**	**–**	**(589)**
Change in gains and losses on derivative instruments designated as cash flow hedges(4)	**–**	**(60)**	**(60)**
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods(5)(6)	**–**	**(23)**	**(23)**
Change in gains and losses on available-for-sale financial instruments(7)	**–**	**2**	**2**
Balance at December 31, 2008	**(379)**	**(93)**	**(472)**

(1) Net of income tax recovery of $104 million in 2008 (2007 – $101 million expense; 2006 – $3 million expense).

(2) Net of income tax recovery of $303 million in 2008 (2007 – $41 million expense; 2006 – $3 million recovery).

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

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

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

(6) The amount of losses related to cash flow hedges reported in accumulated other comprehensive income that will be reclassified to net income in 2009 is estimated to be $62 million ($41 million, net of tax). These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

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

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

TRANSCANADA PIPELINES LIMITED
CONSOLIDATED SHAREHOLDERS' EQUITY

Year ended December 31 *(millions of dollars)*	**2008**	2007	2006
Preferred Shares			
Balance at beginning and end of year	**389**	389	389
Common Shares			
Balance at beginning of year	**6,554**	4,712	4,712
Proceeds from shares issued (Note 17)	**2,419**	1,842	–
Balance at end of year	**8,973**	6,554	4,712
Contributed Surplus			
Balance at beginning of year	**281**	277	275
Other	**3**	4	2
Balance at end of year	**284**	281	277
Retained Earnings			
Balance at beginning of year	**3,202**	2,719	2,267
Net income	**1,442**	1,232	1,099
Preferred share dividends	**(22)**	(22)	(22)
Common share dividends	**(833)**	(731)	(625)
Transition adjustment resulting from adopting new financial instruments accounting standards	**–**	4	–
Balance at end of year	**3,789**	3,202	2,719
Accumulated Other Comprehensive Income, Net of Income Taxes			
Balance at beginning of year	**(373)**	(90)	(90)
Other comprehensive income/(loss)	**(99)**	(187)	–
Transition adjustment resulting from adopting new financial instruments accounting standards	**–**	(96)	–
Balance at end of year	**(472)**	(373)	(90)
	3,317	2,829	2,629
Total Shareholders' Equity	**12,963**	10,053	8,007

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

TRANSCANADA PIPELINES LIMITED
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 DESCRIPTION OF TRANSCANADA PIPELINES LIMITED'S BUSINESS

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

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

- a natural gas transmission system extending from the Alberta/Saskatchewan border east into Québec (Canadian Mainline);
- a natural gas transmission system in Alberta (Alberta System);
- a natural gas transmission system extending from producing fields located primarily in Oklahoma, Texas, Louisiana and the Gulf of Mexico to markets located primarily in Wisconsin, Michigan, Illinois, Ohio and Indiana, and to regulated natural gas storage facilities in Michigan (ANR);
- a natural gas transmission system extending from the British Columbia (B.C.)/Idaho border to the Oregon/California border, traversing Idaho, Washington and Oregon (GTN System);
- a natural gas transmission system extending from central Alberta to the B.C./United States border and to the Saskatchewan/U.S. border (Foothills);
- a natural gas transmission system extending from Arizona to the Baja California, Mexico/California border (North Baja);
- natural gas transmission systems in Alberta that supply natural gas to the oil sands region of northern Alberta and to a petrochemical complex at Joffre, Alberta (Ventures LP);
- a natural gas transmission system in Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi (Tamazunchale);
- a 53.6 per cent direct ownership interest in a natural gas transmission system that connects to the Canadian Mainline and serves markets in Eastern Canada and the northeastern and midwestern 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 pipelines operated by TCPL:
  - a 46.4 per cent interest in Great Lakes, in which TCPL has a combined 68.5 per cent effective ownership interest through PipeLines LP and a direct interest described above;
  - a 50 per cent interest in a natural gas transmission system extending from a point near Monchy, Saskatchewan, to the U.S. Midwest (Northern Border), in which TCPL 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), in which TCPL has a 32.1 per cent effective ownership interest through PipeLines LP.

TCPL owns but does not operate:

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

TCPL has a 62 per cent interest in a pipeline under construction that will transport crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, and at Cushing, Oklahoma (Keystone).

Energy
The Energy segment consists primarily of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities. Through its Energy segment, the Company also sells electricity and holds interests in liquefied natural gas (LNG) regasification projects in North America. Through its Energy segment, TCPL owns and operates:

- natural gas-fired cogeneration plants in Alberta at Carseland, Redwater, Bear Creek and MacKay River;
- a waste-heat fuelled power plant at the Cancarb thermal carbon black facility in Medicine Hat, Alberta (Cancarb);

- a natural gas and oil-fired generating facility in Queens, New York, consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology (Ravenswood);
- hydroelectric generation assets located in New Hampshire, Vermont and Massachusetts (TC Hydro);
- a natural gas-fired, combined-cycle plant in Burrillville, Rhode Island (Ocean State Power);
- a natural gas-fired cogeneration plant near Trois-Rivières, Québec (Bécancour);
- a natural gas-fired cogeneration plant near Saint John, New Brunswick (Grandview); and
- a natural gas storage facility near Edson, Alberta (Edson).

TCPL owns but does not operate:

- a 48.9 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 Tiverton, Ontario;
- a 62 per cent interest in the Baie-des-Sables, Anse-à-Valleau and Carleton wind farms, three of six planned wind farms in Gaspé, Québec (Cartier Wind); and
- a 60 per cent interest in an underground natural gas storage facility near Crossfield, Alberta (CrossAlta).

TCPL 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.

TCPL has interests in the following projects under construction:

- a 50 per cent interest in a natural gas-fired, combined-cycle cogeneration plant near downtown Toronto, Ontario (Portlands Energy);
- a natural gas-fired, combined-cycle power plant near Toronto (Halton Hills); and
- a wind power project located in Kibby and Skinner Townships in northwestern Franklin County, Maine (Kibby Wind).

NOTE 2 ACCOUNTING POLICIES

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

Basis of Presentation

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

Regulation

The Canadian Mainline, Foothills Pipe Lines Ltd. (Foothills) and Trans Québec & Maritimes System (TQM) are subject to the authority of the National Energy Board (NEB) of Canada. The Alberta System is regulated by the Alberta Utilities Commission (AUC). The GTN System and North Baja (collectively, GTN), the ANR Pipeline Company, the ANR Storage Company and the other natural gas pipelines in the U.S. are subject to the authority of the U.S. Federal Energy Regulatory Commission (FERC). These natural gas transmission operations are regulated with respect to construction, operations and the determination of tolls. The timing of recognition of certain revenues and expenses in these regulated businesses may differ from that otherwise expected under GAAP to appropriately reflect the economic impact of the regulators' decisions regarding revenues and tolls. The impact of rate regulation on TCPL is provided in Note 14 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. The Company's natural gas pipeline revenues are generally based on quantity of gas delivered or contracted capacity. Revenues are recognized on firm contracted capacity over the contract period. For interruptible or volumetric-based services, revenues are recorded when physical delivery is made. As the majority of the Company's natural gas pipelines are subject to rate regulation, revenues collected that are subject to rate proceedings may have to be refunded. Revenues from non-regulated operations are recorded when products have been delivered or services have been performed.

Energy

i) Power

Revenues from the Company's Power business are primarily derived from the sale of electricity from energy marketing activities and from the sale of unutilized natural gas fuel, which are recorded in the month of delivery. Revenues also include capacity payments and ancillary services earned as well as the impact of energy derivative contracts, the accounting for which is described in the Financial Instruments section of this note.

ii) Natural Gas Storage

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

Cash and Cash Equivalents

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

Inventories

Effective April 1, 2007, the Company adopted the accounting requirements for the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3031 "Inventories". Inventories primarily consist of materials and supplies, including spare parts, and are carried at the lower of average cost and net realizable value. The Company values its proprietary natural gas inventory held in storage at fair value, as measured by the one-month forward price for natural gas, less selling costs. To record inventory at fair value, TCPL has designated its natural gas storage business as a broker/trader business that purchases and sells natural gas on a back-to-back basis. The Company records its net proprietary natural gas storage sales and purchases in Revenues. All changes in the fair value of the proprietary natural gas inventories are reflected in Inventories and Revenues.

Plant, Property and Equipment

Pipelines

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

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

Energy

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

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

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

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. An initial assessment is made by comparing the fair value of the operations, which includes goodwill, to the book values of each reporting unit. If this fair value is less than book value, an impairment is indicated and a second test is performed to measure the amount of the impairment. In the second test, the implied fair value of the goodwill is calculated by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of the goodwill exceeds the calculated implied fair value of the goodwill, an impairment charge is recorded.

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, with remaining terms ranging from nine to 12 years. The PPAs under which TCPL buys power are accounted for as operating leases. A portion of these PPAs has been subleased to third parties under similar terms and conditions. The subleases are accounted for as operating leases and TCPL records the margin earned from the subleases as a component of Revenues.

Income Taxes
The taxes payable method of accounting for income taxes is used for tollmaking purposes for 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 at December 31, 2008, 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 all of the Company's other operations. Under the liability method, future income 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 during 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 monetary assets and liabilities are recorded in income except for exchange gains or losses on the principal amounts of foreign currency debt related to the Alberta System, Foothills and Canadian Mainline, which are deferred until they are refunded or recovered in tolls, as permitted by regulatory bodies.

Financial Instruments
Effective January 1, 2007, the Company adopted the accounting requirements for CICA Handbook Sections 1530 "Comprehensive Income", 3855 "Financial Instruments – Recognition and Measurement", and 3865 "Hedges". Effective December 31, 2007, the Company adopted the accounting requirements for CICA Handbook Sections 3862 "Financial Instruments – Disclosure", 3863 "Financial Instruments – Presentation", and 1535 "Capital Disclosures". Adjustments to the consolidated financial statements for 2007 were made on a prospective basis.

The CICA Handbook requires that all financial instruments 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 derivative financial assets and liabilities consist of swaps, options, forwards and futures. A financial asset or liability may be designated as held for trading if it is entered into with the intention of generating a profit. The Company has not designated any non-derivative financial assets or liabilities as held for trading. Commodity held-for-trading financial instruments are initially recorded at their fair value and changes to fair value are included in Revenues. Changes in the fair value of interest rate and foreign exchange rate held-for-trading instruments are recorded in Financial Charges and in Interest Income and Other, respectively.

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

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

Trade receivables, loans and other receivables with fixed or determinable payments that are not quoted in an active market are classified as "loans and receivables" and are measured at amortized cost using the effective interest method, net of any impairment. 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. Items in this financial instrument category are recognized at amortized cost using the effective interest method. Interest expense is included in Financial Charges and in Financial Charges of Joint Ventures.

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

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

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

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

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

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

Hedges

The CICA Handbook 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 hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

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 are also recorded in Net Income. Changes in the fair value of foreign exchange and interest rate fair value hedges are recorded in Interest Income and Other and 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 from Accumulated Other Comprehensive Income when the hedged item is sold or terminated early, or when a hedged anticipated transaction is no longer expected to occur.

The Company also enters into cash flow hedges and fair value hedges for activities subject to rate regulation. 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 reclassified to Net Income in the event the Company settles or otherwise reduces its investment in a foreign operation.

Asset Retirement Obligations

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

It is not possible to determine the scope and timing of asset retirements related to regulated natural gas pipelines and, therefore, it is 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 regulated natural gas pipelines, with the exception of certain 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, it is 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 plants. With respect to the nuclear assets leased by Bruce Power, the Company has not recorded an amount for asset retirement obligations, as Bruce Power leases the assets and the lessor is responsible for decommissioning liabilities under the lease agreement.

Environmental Liabilities

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

Employee Benefit and Other Plans

The Company sponsors defined benefit pension plans (DB Plans), defined contributions plans (DC Plans), a Savings Plan and other post-employment plans. Contributions made by the Company to the DC Plans and Savings Plan 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 of the DB Plans' assets. Past service costs are amortized over the expected average remaining service life of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized over the average remaining service period of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

The Company has medium-term incentive plans, which are payable in cash to eligible employees. 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 3 ACCOUNTING CHANGES

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, was withdrawn. In addition, Section 3465 "Income Taxes" was amended to require the recognition of future income tax assets and liabilities for rate-regulated entities. The Company has chosen to adopt accounting policies consistent with the U.S. Financial Accounting Standards Board's Financial Accounting Standard (FAS) 71 "Accounting for the Effects of Certain Types of Regulation". Accordingly, TCPL will retain its current method of accounting for its rate-regulated operations, except that TCPL will be required to recognize future income tax assets and liabilities instead of using the taxes payable method, and will record an offsetting adjustment to regulatory assets and liabilities. If the Company had adopted FAS 71, at December 31, 2008, additional future income tax liabilities and a regulatory asset in the amount of $1,434 million would have been recorded and would have been recoverable from future revenue. These changes will be applied retrospectively without restatement beginning January 1, 2009.

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 International Financial Reporting Standards (IFRS) and U.S. GAAP. CICA Handbook 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 International Accounting Standards Board's (IASB) "Framework for the Preparation and Presentation of Financial Statements" that helps distinguish assets from expenses. CICA Handbook Section 3064 "Goodwill and Intangible Assets", which replaced CICA Handbook 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. In addition, CICA Handbook 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.

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

International Financial Reporting Standards
The CICA's Accounting Standards Board announced that Canadian publicly accountable enterprises are required to adopt IFRS, as issued by the IASB, effective January 1, 2011. In June 2008, the Canadian Securities Administrators proposed that Canadian public companies that are also U.S. Securities and Exchange Commission (SEC) registrants, such as TCPL, retain the option to prepare their financial statements under U.S. GAAP instead of IFRS. In November 2008, the SEC issued for public comment a recommendation that, beginning in 2014, U.S. issuers be required to adopt IFRS using a phased-in approach based on market capitalization.

TCPL is currently considering the impact a conversion to IFRS or U.S. GAAP would have on its accounting systems and financial statements. TCPL's conversion project planning includes an analysis of project structure and governance, resources and training, analysis of key GAAP differences and a phased approach to the assessment of current accounting policies and implementation.

Under existing Canadian GAAP, TCPL follows specific accounting policies unique to rate-regulated businesses. TCPL is actively monitoring ongoing discussions and developments at the IASB regarding potential future guidance to clarify the applicability of certain aspects of rate-regulated accounting under IFRS. The IASB is expected to issue a proposed standard for rate-regulated businesses in 2009.

NOTE 4 SEGMENTED INFORMATION

NET INCOME[(1)]

Year ended December 31, 2008 (millions of dollars)	**Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	**4,650**	**3,969**	**–**	**8,619**
Plant operating costs and other	**(1,732)**	**(1,326)**	**(4)**	**(3,062)**
Commodity purchases resold	**–**	**(1,511)**	**–**	**(1,511)**
Depreciation	**(989)**	**(200)**	**–**	**(1,189)**
	1,929	**932**	**(4)**	**2,857**
Financial charges	**(674)**	**–**	**(288)**	**(962)**
Financial charges of joint ventures	**(49)**	**(23)**	**–**	**(72)**
Interest income and other	**73**	**6**	**1**	**80**
Calpine bankruptcy settlements	**279**	**–**	**–**	**279**
Writedown of Broadwater LNG project costs	**–**	**(41)**	**–**	**(41)**
Income taxes	**(548)**	**(260)**	**217**	**(591)**
Non-controlling interests and preferred share dividends	**(108)**	**–**	**(22)**	**(130)**
Net Income Applicable to Common Shares	**902**	**614**	**(96)**	**1,420**

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	(718)	1	(244)	(961)
Financial charges of joint ventures	(52)	(23)	–	(75)
Interest income and other	52	10	88	150
Gain on sale of assets	–	16	–	16
Income taxes	(470)	(208)	195	(483)
Non-controlling interests and preferred share dividends	(75)	–	(22)	(97)
Net Income Applicable to Common Shares	686	514	10	1,210

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	(711)	–	(117)	(828)
Financial charges of joint ventures	(69)	(23)	–	(92)
Interest income and other	100	5	51	156
Gain on sale of assets	23	–	–	23
Income taxes	(410)	(198)	133	(475)
Non-controlling interests and preferred share dividends	(56)	–	(22)	(78)
Net income from continuing operations	560	452	37	1,049
Net income from discontinued operations				28
Net Income Applicable to Common Shares				1,077

(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)	**2008**	2007
Pipelines	**25,020**	22,024
Energy	**12,006**	7,037
Corporate	**3,909**	2,676
	40,935	31,737

GEOGRAPHIC INFORMATION

Year ended December 31 (millions of dollars)	**2008**	2007	2006
Revenues[1]			
Canada – domestic	**4,599**	5,019	4,956
Canada – export	**1,125**	1,006	972
United States and other	**2,895**	2,803	1,592
	8,619	8,828	7,520

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

December 31 (millions of dollars)	**2008**	2007
Plant, Property and Equipment		
Canada	**18,041**	16,741
United States	**10,973**	6,564
Mexico	**175**	147
	29,189	23,452

CAPITAL EXPENDITURES

Year ended December 31 (millions of dollars)	**2008**	2007	2006
Pipelines	**1,854**	564	560
Energy	**1,266**	1,079	976
Corporate	**14**	8	36
	3,134	1,651	1,572

NOTE 5 PLANT, PROPERTY AND EQUIPMENT

	2008			2007		
December 31 (millions of dollars)	**Cost**	**Accumulated Depreciation**	**Net Book Value**	Cost	Accumulated Depreciation	Net Book Value
Pipelines[1]						
Canadian Mainline						
Pipeline	**8,740**	**4,269**	**4,471**	8,889	4,149	4,740
Compression	**3,373**	**1,399**	**1,974**	3,371	1,303	2,068
Metering and other	**344**	**140**	**204**	345	140	205
	12,457	**5,808**	**6,649**	12,605	5,592	7,013
Under construction	**16**	**–**	**16**	28	–	28
	12,473	**5,808**	**6,665**	12,633	5,592	7,041
Alberta System						
Pipeline	**5,518**	**2,637**	**2,881**	5,258	2,504	2,754
Compression	**1,552**	**914**	**638**	1,522	842	680
Metering and other	**846**	**317**	**529**	831	297	534
	7,916	**3,868**	**4,048**	7,611	3,643	3,968
Under construction	**354**	**–**	**354**	120	–	120
	8,270	**3,868**	**4,402**	7,731	3,643	4,088
ANR						
Pipeline	**976**	**69**	**907**	772	25	747
Compression	**579**	**61**	**518**	424	32	392
Metering and other	**686**	**50**	**636**	483	6	477
	2,241	**180**	**2,061**	1,679	63	1,616
Under construction	**31**	**–**	**31**	69	–	69
	2,272	**180**	**2,092**	1,748	63	1,685
GTN						
Pipeline	**1,482**	**215**	**1,267**	1,181	134	1,047
Compression	**562**	**63**	**499**	436	39	397
Metering and other	**134**	**23**	**111**	81	3	78
	2,178	**301**	**1,877**	1,698	176	1,522
Under construction	**30**	**–**	**30**	31	–	31
	2,208	**301**	**1,907**	1,729	176	1,553
Great Lakes	**1,875**	**744**	**1,131**	1,509	552	957
Foothills	**1,655**	**873**	**782**	1,647	819	828
Northern Border	**1,530**	**682**	**848**	1,232	528	704
Keystone – under construction	**1,361**	**–**	**1,361**	158	–	158
Other[2]	**2,078**	**566**	**1,512**	1,705	439	1,266
	8,499	**2,865**	**5,634**	6,251	2,338	3,913
	33,722	**13,022**	**20,700**	30,092	11,812	18,280
Energy						
Nuclear[3]	**1,604**	**364**	**1,240**	1,479	286	1,193
Natural gas/oil – Ravenswood[4]	**1,977**	**22**	**1,955**	n/a[5]	n/a	n/a
Natural gas – Other[6]	**1,702**	**504**	**1,198**	1,570	383	1,187
Hydro	**628**	**48**	**580**	503	28	475
Wind	**391**	**18**	**373**	288	6	282
Natural gas storage	**374**	**46**	**328**	358	33	325
Other	**156**	**82**	**74**	137	78	59
	6,832	**1,084**	**5,748**	4,335	814	3,521
Under construction[7]	**2,687**	**–**	**2,687**	1,606	–	1,606
	9,519	**1,084**	**8,435**	5,941	814	5,127
Corporate	**74**	**20**	**54**	60	15	45
	43,315	**14,126**	**29,189**	36,093	12,641	23,452

(1) In 2008, the Company capitalized $27 million (2007 – $14 million) relating to AFUDC.

(2) Pipelines – Other primarily includes assets of Iroquois, Portland, TQM, Tuscarora and Tamazunchale.

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

(4) TCPL acquired Ravenswood on August 26, 2008.

(5) Not applicable, as there are no comparative amounts for prior years.

(6) Certain owned power generation facilities with long-term PPAs are accounted for as assets under operating leases. The net book value of these facilities was $77 million at December 31, 2008 (2007 – $78 million). Revenues of $14 million were recognized in 2008 (2007 – $16 million) through the sale of electricity under the related PPAs.

(7) Energy assets under construction primarily include expenditures for the Bruce A refurbishment and restart, and for construction of Halton Hills, Portland Energy, Kibby Wind and Coolidge.

NOTE 6 GOODWILL

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

(millions of dollars)	Pipelines	Energy	Total
Balance at January 1, 2007	281	–	281
Acquisition of ANR	2,235	–	2,235
Acquisition of additional interests in Great Lakes	573	–	573
Acquisition of additional interest in Tuscarora	3	–	3
Foreign exchange and adjustments	(459)	–	(459)
Balance at December 31, 2007	2,633	–	2,633
Acquisition of Ravenswood	**–**	**949**	**949**
Foreign exchange and adjustments	**749**	**66**	**815**
Balance at December 31, 2008	**3,382**	**1,015**	**4,397**

NOTE 7 OTHER ASSETS

December 31 (millions of dollars)	**2008**	2007
PPAs[(1)]	**651**	709
Prepaid operating lease[(2)]	**369**	n/a
Pension and other benefit plans (Note 22)	**234**	234
Regulatory assets (Note 14)	**201**	336
Fair value of derivative contracts (Note 18)	**191**	204
Loans and advances[(3)] (Note 24)	**140**	137
Deferred project development costs[(4)]	**116**	40
Equity investments[(5)]	**85**	63
Other	**241**	217
	2,228	1,940

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

	2008			2007		
December 31 (millions of dollars)	**Cost**	**Accumulated Amortization**	**Net Book Value**	Cost	Accumulated Amortization	Net Book Value
PPAs	**915**	**264**	**651**	915	206	709

Amortization expense for the PPAs was $58 million for the year ended December 31, 2008 (2007 – $58 million; 2006 – $58 million). The expected annual amortization expense in each of the next five years is: 2009 – $58 million; 2010 – $58 million; 2011 – $57 million; 2012 – $57 million; and 2013 – $57 million.

(2) The balance at December 31, 2008 represents the long-term portion of a prepaid operating lease from the acquisition of Ravenswood. The expected annual operating lease expense in each of the next five years is US$10 million.

(3) The balance at December 31, 2008 represents a $140-million loan (2007 – $137 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.

(4) The balance at December 31, 2008 includes $74 million (2007 – nil) related to the proposed expansion of the Keystone pipeline project and $42 million related to the Bison pipeline project. The balance of $40 million at December 31, 2007 related to the Broadwater LNG project and, in 2008, TCPL wrote down $41 million of capitalized costs related to this project after the New York Department of State rejected a proposal to construct this facility.

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

NOTE 8 JOINT VENTURE INVESTMENTS

		TCPL's Proportionate Share				
	Ownership Interest as at December 31,	Income/(Loss) Before Income Taxes Year ended December 31			Net Assets December 31	
(millions of dollars)	2008	**2008**	2007	2006	**2008**	2007
Pipelines						
Northern Border[(1)]		**59**	67	52	**479**	415
Iroquois	44.5%	**32**	25	25	**239**	163
TQM	50.0%	**12**	11	11	**69**	74
Keystone	61.9%[(2)]	**(7)**	n/a	n/a	**906**	207
Great Lakes[(3)]		**–**	13	69	**–**	–
Other	Various	**15**	13	6	**70**	48
Energy						
Bruce A	48.9%	**46**	8	75	**2,012**	1,640
Bruce B	31.6%	**136**	140	140	**429**	325
CrossAlta	60.0%	**44**	59	64	**56**	38
Cartier Wind	62.0%[(4)]	**12**	10	2	**365**	275
TC Turbines	50.0%	**9**	5	5	**31**	29
Portlands Energy	50.0%	**–**	–	–	**334**	269
ASTC Power Partnership	50.0%[(5)]	**–**	–	–	**70**	76
		358	351	449	**5,060**	3,559

(1) 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 TCPL's 32.1 per cent ownership interest in PipeLines LP, Northern Border became a jointly controlled entity and TCPL 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, 2008 and 2007.

(2) In December 2007, ConocoPhillips exercised its option to become a 50 per cent partner with TCPL in Keystone. As a result, TCPL 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. In 2008, TCPL agreed to increase its equity ownership in the Keystone partnerships to 79.99 per cent. ConocoPhillips' equity ownership will be reduced concurrently to 20.01 per cent. TCPL's increase in ownership is expected to occur as the Company funds 100 per cent of the construction expenditures until the participants' project capital contributions are aligned with the revised ownership interests. At December 31, 2008, TCPL's equity ownership in the Keystone partnerships was 61.9 per cent (December 31, 2007 – 50.0 per cent), however, strategic, operational and financial decisions are made jointly with ConocoPhillips.

(3) In February 2007, TCPL 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 TCPL an indirect 14.9 per cent interest in Great Lakes. As a result of these transactions, the Company's effective ownership interest in Great Lakes, net of non-controlling interests, was 68.5 per cent at December 31, 2008 and 2007. TCPL commenced consolidating its investment in Great Lakes on a prospective basis effective February 22, 2007.

(4) TCPL proportionately consolidates its 62 per cent interest in the Cartier Wind assets. The first three phases of the six-phase Cartier Wind project, Baie-des-Sables, Anse-à-Valleau and Carleton, began operating in November 2006, 2007 and 2008, respectively.

(5) The Company has a 50 per cent ownership interest in ASTC Power Partnership, an Alberta partnership which holds the Sundance B PPA. The underlying power volumes related to this ownership interest are effectively transferred to TCPL.

Summarized Financial Information of Joint Ventures

Year ended December 31 (millions of dollars)	**2008**	2007	2006
Income			
Revenues	**1,264**	1,305	1,382
Plant operating costs and other	**(683)**	(736)	(686)
Depreciation	**(154)**	(150)	(163)
Financial charges and other	**(69)**	(68)	(84)
Proportionate share of joint venture income before income taxes	**358**	351	449

Year ended December 31 (millions of dollars)	**2008**	2007	2006
Cash Flows			
Operating activities	**1,067**	420	645
Investing activities	**(2,031)**	(761)	(641)
Financing activities(1)	**952**	409	(31)
Effect of foreign exchange rate changes on cash and cash equivalents	**23**	(8)	9
Proportionate share of increase/(decrease) in cash and cash equivalents of joint ventures	**11**	60	(18)

(1) Financing activities included cash outflows resulting from distributions paid to TCPL of $287 million in 2008 (2007 – $361 million; 2006 – $470 million) and cash inflows resulting from capital contributions paid by TCPL of $1,067 million in 2008 (2007 – $771 million; 2006 – $452 million).

December 31 (millions of dollars)	**2008**	2007
Balance Sheet		
Cash and cash equivalents	**181**	170
Other current assets	**159**	343
Plant, property and equipment	**6,341**	4,283
Other assets/(deferred amounts), net	**45**	(69)
Current liabilities	**(793)**	(293)
Long-term debt	**(871)**	(873)
Future income taxes	**(2)**	(2)
Proportionate share of net assets of joint ventures	**5,060**	3,559

NOTE 9 ACQUISITIONS AND DISPOSITIONS

Acquisitions

Pipelines

Keystone
In 2008, TCPL agreed to increase its equity ownership in the Keystone partnerships up to 79.99 per cent from 50 per cent, with ConocoPhillips' equity ownership being reduced concurrently to 20.01 per cent. The increase in ownership is expected to occur as TCPL funds 100 per cent of the construction expenditures until the participants' project capital contributions are aligned with the revised ownership interests. In accordance with the agreement, TCPL funded $362 million of cash calls, resulting in the acquisition of an incremental 12 per cent ownership interest for $176 million, bringing TCPL's ownership interest to 62 per cent at December 31, 2008. TCPL continues to proportionately consolidate the Keystone partnerships.

During 2008, Keystone purchased pipeline facilities located in Saskatchewan and Manitoba from the Canadian Mainline for use in the construction of the Keystone oil pipeline. The sale was completed in three phases for total proceeds of $65 million, with no gain recognized on the sale.

ANR and Great Lakes
On February 22, 2007, TCPL acquired from El Paso Corporation 100 per cent of American Natural Resources Company and ANR Storage Company (collectively, 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, including US$491 million of assumed long-term debt. The acquisitions were accounted for using the purchase method of accounting. TCPL began consolidating ANR and Great Lakes in the Pipelines segment after the acquisition date. The purchase price was allocated as follows:

Purchase Price Allocation

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

TC PipeLines, LP Acquisition of Interest in Great Lakes
On February 22, 2007, PipeLines LP acquired from El Paso Corporation a 46.4 per cent interest in Great Lakes for US$942 million, including US$209 million of assumed long-term debt. The acquisition was accounted for using the purchase method of accounting. TCPL began consolidating Great Lakes in the Pipelines segment after the acquisition date. As of February 2007, TCPL's effective ownership interest in Great Lakes was 68.5 per cent, comprising its direct ownership interest and its indirect ownership interest through PipeLines LP. The purchase price was allocated as follows:

Purchase Price Allocation

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

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

Factors that contributed to goodwill included the opportunity to expand in the U.S. market and to gain a stronger competitive position in the North American gas transmission business. Goodwill related to TCPL'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
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. TCPL acquired 50 per cent of the units for US$300 million. TCPL also invested an additional US$12 million to maintain its general partnership interest in PipeLines LP. As a result of these additional investments, TCPL's ownership in PipeLines LP increased to 32.1 per cent on February 22, 2007. The total private placement, together with TCPL'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
In December 2007, 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 addition, PipeLines LP purchased TCPL's one per cent interest in Tuscarora for

US$2 million. Beginning December 2007, PipeLines LP owned 100 per cent of Tuscarora, resulting in TCPL's effective ownership of 32.1 per cent, net of non-controlling interests.

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.

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. As of April 2006, PipeLines LP owned 50 per cent of Northern Border, giving TCPL effective ownership of 16.1 per cent, net of non-controlling interests.

Energy

Ravenswood

On August 26, 2008, TCPL acquired from National Grid plc 100 per cent of the 2,480 MW Ravenswood power facility for US$2.9 billion, subject to certain post-closing adjustments. The acquisition was accounted for using the purchase method of accounting. TCPL began consolidating Ravenswood in the Energy segment subsequent to the acquisition date.

The preliminary allocation of the purchase price at December 31, 2008 was as follows:

Purchase Price Allocation

(millions of US dollars)	
Current assets	149
Plant, property and equipment	1,666
Other non-current assets	305
Goodwill	835
Current liabilities	(19)
Other non-current liabilities	(20)
	2,916

A preliminary allocation of the purchase price, subject to certain post-closing adjustments, has been made using fair values of the net assets at the date of acquisition. Factors that contributed to goodwill included the opportunity to expand the Energy segment further in the U.S. market and to gain a stronger competitive position in the North American power generation business. The goodwill recognized on this transaction is amortizable for tax purposes.

Dispositions

Pipelines

Northern Border Partners, L.P. Interest

In April 2006, TCPL sold its 17.5 per cent general partner interest in Northern Border Partners, L.P., 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.

Energy

Ontario Land Sale

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

NOTE 10 LONG-TERM DEBT

Outstanding loan amounts (millions of dollars unless otherwise indicated)	Maturity Dates	**2008** Outstanding December 31	**2008** Interest Rate[1]	2007 Outstanding December 31	2007 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian dollars	2009 to 2020	**1,251**	**10.8%**	1,351	10.9%
U.S. dollars (2008 and 2007 – US$600)[2]	2012 to 2021	**734**	**9.5%**	594	9.5%
Medium-Term Notes					
Canadian dollars[3]	2009 to 2031	**3,653**	**5.3%**	3,413	6.1%
Senior Unsecured Notes					
U.S. dollars (2008 – US$4,723; 2007 – US$3,223)[4]	2009 to 2038	**5,751**	**6.3%**	3,161	6.0%
		11,389		8,519	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian dollars	2010 to 2024	**439**	**11.5%**	501	11.6%
U.S. dollars (2008 and 2007 – US$375)	2012 to 2023	**457**	**8.2%**	368	8.2%
Medium-Term Notes					
Canadian dollars	2025 to 2030	**502**	**7.4%**	607	7.2%
U.S. dollars (2008 and 2007 – US$33)	2026	**39**	**7.5%**	32	7.5%
		1,437		1,508	
TRANSCANADA PIPELINE USA LTD.					
Bank Loan					
U.S. dollars (2008 – US$700; 2007 – US$860)	2012	**857**	**2.4%**	850	5.7%
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. dollars (2008 and 2007 – US$444)	2010 to 2025	**541**	**9.1%**	435	9.1%
GAS TRANSMISSION NORTHWEST CORPORATION					
Senior Unsecured Notes					
U.S. Dollars (2008 and 2007 – US$400)	2010 to 2035	**488**	**5.4%**	399	5.4%
TC PIPELINES, LP					
Unsecured Loan					
U.S. dollars (2008 – US$475; 2007 – US$507)	2011	**580**	**2.7%**	499	6.2%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. dollars (2008 – US$430; 2007 – US$440)	2011 to 2030	**526**	**7.8%**	434	7.8%
TUSCARORA GAS TRANSMISSION COMPANY					
Senior Unsecured Notes					
U.S. dollars (2008 – US$64; 2007 – US$69)	2010 to 2012	**78**	**7.4%**	67	7.4%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Secured Notes					
U.S. dollars (2008 – US$196; 2007 – US$211)[5]	2018	**236**	**6.1%**	205	6.1%
OTHER					
Senior Notes					
U.S. dollars (2008 – US$18; 2007 – US$17)	2011	**22**	**7.3%**	17	7.3%
		16,154		12,933	
Less: Current Portion of Long-Term Debt		**786**		556	
		15,368		12,377	

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

(2) Includes fair value adjustments for interest rate swap agreements on US$50 million of debt at December 31, 2008 and 2007.

(3) Includes fair value adjustments for interest rate swap agreements on $50 million of debt at December 31, 2008 (2007 – $150 million).

(4) Includes fair value adjustments for interest rate swap agreements on US$150 million of debt at December 31, 2008 and 2007.

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

Principal Repayments
Principal repayments on the long-term debt of the Company for the next five years are approximately as follows: 2009 – $786 million; 2010 – $531 million; 2011 – $1,014 million; 2012 – $1,370 million; and 2013 – $1,180 million.

Debt Shelf Programs – TransCanada PipeLines Limited
In January 2009, the Company filed a debt shelf prospectus in the U.S. qualifying for issuance US$3.0 billion of debt securities.

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. Subsequent to the February 2009 debt issue discussed below, the Company had $300 million of remaining capacity available under the Canadian shelf 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. At December 31, 2008, the Company had fully utilized its capacity under the September 2007 U.S. shelf prospectus.

TransCanada PipeLines Limited
On February 17, 2009, TCPL completed the issuance of Medium-Term Notes of $300 million and $400 million maturing in February 2014 and February 2039, respectively, and bearing interest at 5.05 per cent and 8.05 per cent, respectively. These notes were issued under the $1.5 billion debt shelf prospectus filed in Canada in March 2007.

On January 9, 2009, TCPL issued US$750 million and US$1.25 billion of Senior Unsecured Notes maturing in January 2019 and January 2039, respectively, and bearing interest at 7.125 per cent and 7.625 per cent, respectively. These notes were issued under the January 2009 U.S. debt shelf prospectus.

In August 2008, TCPL issued $500 million of Medium-Term Notes maturing in August 2013, and bearing interest at 5.05 per cent under the March 2007 Canadian debt shelf prospectus.

In August 2008, TCPL issued US$850 million and US$650 million of Senior Unsecured Notes maturing in August 2018 and August 2038, respectively, and bearing interest at 6.50 per cent and 7.25 per cent, respectively. These notes were issued under the September 2007 U.S. debt shelf prospectus.

In October 2007, TCPL issued US$1.0 billion of Senior Unsecured Notes under the U.S. debt shelf filed in September 2007.

NOVA Gas Transmission Ltd.
Debentures issued by NOVA Gas Transmission Ltd. (NGTL) in the amount of $225 million have retraction provisions that entitle the holders to require redemption of up to eight per cent of the then outstanding principal plus accrued and unpaid interest on specified repayment dates. No redemptions were made to December 31, 2008.

TransCanada PipeLine USA Ltd.
In February 2007, TransCanada PipeLine USA Ltd. established a US$1.0 billion committed, unsecured, syndicated credit facility, consisting of a US$700-million five-year term loan and a US$300-million five-year, extendible revolving facility. There was an outstanding balance of US$700 million and US$860 million on the credit facility at December 31, 2008 and 2007, respectively. In 2008, the maturity date of the revolving portion of the facility was extended to February 2013.

TC PipeLines, LP

In February 2007, PipeLines LP increased 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. During 2008, an additional US$13 million (2007 – US$18 million) of the senior term loan was terminated due to principal repayments. There was an outstanding balance of US$475 million and US$507 million on the credit facility at December 31, 2008 and 2007, respectively.

Sensitivity

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

(millions of dollars)	Increase	Decrease
Effect on fair value of fixed interest rate debt	(895)	1,014
Effect on interest expense of variable interest rate debt	2	(2)

Financial Charges

Year ended December 31 (millions of dollars)	**2008**	2007	2006
Interest on long-term debt	**970**	986	849
Interest on junior subordinated notes	**68**	43	n/a
Interest on short-term debt	**51**	28	23
Capitalized interest	**(141)**	(68)	(60)
Amortization and other financial charges[1]	**14**	(28)	16
	962	961	828

[1] Amortization and other financial charges in 2008 and 2007 included amortization of transaction costs and debt discounts calculated using the effective interest method.

The Company made interest payments of $869 million in 2008 (2007 – $944 million; 2006 – $771 million).

NOTE 11 LONG-TERM DEBT OF JOINT VENTURES

Outstanding loan amounts (millions of dollars)	Maturity Dates	**2008** Outstanding December 31(1)	**2008** Interest Rate(2)	2007 Outstanding December 31(1)	2007 Interest Rate(2)
NORTHERN BORDER PIPELINE COMPANY					
Senior Unsecured Notes (2008 – US$225; 2007 – US$232)	2009 to 2021	**275**	**7.7%**	229	7.7%
Bank Facility (2008 – US$96; 2007 – US$83)	2012	**116**	**3.4%**	82	5.3%
IROQUOIS GAS TRANSMISSION SYSTEM, L.P.					
Senior Unsecured Notes (2008 – US$160; 2007 – US$165)	2010 to 2027	**195**	**7.6%**	162	7.5%
Bank Loan (2007 – US$7)		**–**		7	7.4%
BRUCE POWER L.P. AND BRUCE POWER A L.P.					
Capital Lease Obligations	2018	**235**	**7.5%**	243	7.5%
Term Loan	2031	**95**	**7.1%**	n/a	
TRANS QUÉBEC & MARITIMES PIPELINE INC.					
Bonds	2009 to 2010	**137**	**6.0%**	137	6.0%
Term Loan	2011	**18**	**1.9%**	28	4.6%
OTHER	2009 to 2010	**5**	**5.5%**	15	4.5%
		1,076		903	
Less: Current Portion of Long-Term Debt of Joint Ventures		**207**		30	
		869		873	

(1) Amounts outstanding represent TCPL'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. Weighted average and effective interest rates are stated as at the respective outstanding dates. At December 31, 2008, the effective interest rate resulting from swap agreements was 4.1 per cent on the Northern Border bank facility (2007 – nil). At December 31, 2007, the effective interest rate resulting from swap agreements was 7.5 per cent on the Iroquois bank loan.

The long-term debt of joint ventures is non-recourse to TCPL, except that TCPL has provided certain pro-rata guarantees related to the capital lease obligations of Bruce Power. The security provided with respect to the debt of each joint venture is limited to the rights and assets of the joint venture and does not extend to the rights and assets of TCPL, except to the extent of TCPL's investment. 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 for the next five years resulting from maturities and sinking fund obligations of the non-recourse joint venture debt is approximately as follows: 2009 – $194 million; 2010 – $212 million; 2011 – $30 million; 2012 – $126 million; and 2013 – $8 million.

The Company's proportionate share of principal payments for the next five years resulting from the capital lease obligations of Bruce Power is approximately as follows: 2009 – $13 million; 2010 – $13 million; 2011 – $15 million; 2012 – $18 million; and 2013 – $20 million.

In September 2008, Bruce A entered into a $193 million unsecured term loan, maturing December 2031 and bearing interest at 7.12 per cent.

In April 2007, Northern Border established a US$250-million five-year unsecured 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.

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	(39)	44
Effect on interest expense of variable interest rate debt	1	(1)

Financial Charges of Joint Ventures

Year ended December 31 (millions of dollars)	**2008**	2007	2006
Interest on long-term debt	**45**	50	67
Interest on capital lease obligations	**18**	18	19
Short-term interest and other financial charges	**7**	4	3
Deferrals and amortization	**2**	3	3
	72	75	92

The Company's proportionate share of the interest payments of joint ventures was $50 million in 2008 (2007 – $45 million; 2006 – $73 million).

The Company's proportionate share of interest payments from the capital lease obligations of Bruce Power was $18 million in 2008 (2007 – $18 million; 2006 – $20 million).

NOTE 12 JUNIOR SUBORDINATED NOTES

		2008		2007	
Outstanding loan amount (millions of dollars)	Maturity Dates	**Outstanding December 31**	**Effective Interest Rate**	Outstanding December 31	Effective Interest Rate
TRANSCANADA PIPELINES LIMITED					
U.S. dollars (2008 and 2007 – US$1,000)	2017	**1,213**	**6.5%**	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 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, in whole or in part, upon the occurrence of certain events and at the Company's option at an amount equal to the greater of 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption and an amount determined by a specified formula in accordance with the terms of the Junior Subordinated Notes. The Junior Subordinated Notes were issued under the U.S. debt 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	(45)	49

NOTE 13 DEFERRED AMOUNTS

December 31 (millions of dollars)	**2008**	2007
Fair value of derivative contracts (Note 18)	**694**	205
Regulatory liabilities (Note 14)	**551**	525
Employee benefit plans (Note 22)	**219**	196
Asset retirement obligations (Note 21)	**114**	88
Other	**141**	93
	1,719	1,107

NOTE 14 REGULATED BUSINESSES

TCPL's regulated businesses include Canadian and U.S. natural gas pipelines. Regulatory assets and liabilities represent future revenues that are expected to be recovered from or refunded to customers. They arise from certain costs and revenues generated in the current period or in prior periods that may be collected from or refunded to shippers if, through the rate-setting process, it is found that revenues were over- or under-collected. Regulatory assets and liabilities are only recognized when approved by the applicable regulatory authorities. In addition to GAAP financial reporting, TCPL's regulated pipelines file financial reports using accounting regulations required by their respective regulators.

Canadian Regulated Operations

Canadian natural gas transmission services are supplied under 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 TCPL'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 specified annual return on capital, including debt and equity, and all necessary operating expenses, taxes and depreciation.

TCPL'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 and revenues are more or less than the forecasted costs and revenues, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in rates at that time. Costs for which the regulator does not allow the difference between actual and forecast to be deferred are included in the determination of net income in the year they are incurred.

The Canadian Mainline, Foothills and TQM pipelines are regulated by the NEB under the *National Energy Board Act (Canada)*. The Alberta System is regulated by the AUC primarily under the provisions of the *Gas Utilities Act (Alberta)* and the *Pipeline Act (Alberta)*. The AUC regulates the construction and operation of facilities, and the terms and conditions of services, including rates for the Alberta System. 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 natural gas transmission systems. The Alberta System has filed an application with the NEB to change its regulatory jurisdiction from the AUC to the NEB. The NEB's decision is expected in first quarter 2009.

Canadian Mainline

The Canadian Mainline currently operates under a five-year tolls settlement, which is effective January 1, 2007, to December 31, 2011. Canadian Mainline's cost of capital for establishing tolls under the settlement reflects 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. The allowed ROE in 2008 for Canadian Mainline was 8.71 per cent (2007 – 8.46 per cent). The remaining capital structure consists of short- and long-term debt following the agreed-upon redemption of US$460 million of Preferred Securities in 2007.

The settlement also establishes the Canadian Mainline's fixed operations, maintenance and administrative (OM&A) costs for each year of the five years. Any variance between actual OM&A costs and those agreed to in the settlement accrue to TCPL from 2007 to 2009. Variances in OM&A costs will be shared equally between TCPL and its customers in 2010 and 2011. All other cost elements of the revenue requirement are treated on a flow-through basis. There are also performance-based incentive arrangements that provide mutual benefits to both TCPL and its customers.

Alberta System

In March 2008, NOVA Gas Transmission Ltd. (NGTL) reached a revenue requirement settlement with interested stakeholders for 2008 and 2009 on the Alberta System. In December 2008, the AUC approved the 2008-2009 Revenue Requirement Settlement Application, which is effective for the full two-year period.

As part of the settlement, fixed costs were established for certain operating costs, ROE and income taxes. Any variances between actual costs and those agreed to in the settlement accrue to TCPL, subject to ROE and income tax adjustment mechanisms. All other costs of the revenue requirement are treated on a flow-through basis.

Other Canadian Pipelines

The NEB approves pipeline tolls on an annual cost of service basis for Foothills and TQM. 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.

The ROE for Foothills, which is based on the NEB-allowed ROE formula, was 8.71 per cent in 2008 (2007 – 8.46 per cent) on a deemed equity component of 36 per cent.

In September 2008, the NEB approved TQM's application for a three-year partial negotiated settlement with interested parties concerning all cost of service matters, with the exception of cost of capital and associated income taxes, for the years 2007 to 2009. In December 2007, TQM filed a cost of capital application with the NEB for the years 2007 and 2008, which requests approval of an 11 per cent return on deemed common equity of 40 per cent. An NEB hearing on the application concluded in October 2008 and a decision from the NEB is expected in early 2009. TQM currently is subject to the 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

TCPL'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 *Energy Policy Act of 2005*, and are subject to the jurisdiction of the FERC. The *Natural Gas Act of 1938* grants the FERC authority over the construction and operation of pipelines and related facilities. The FERC also has authority to regulate rates for natural gas transportation in interstate commerce.

ANR

ANR's operations are regulated primarily by the FERC. ANR's natural gas storage and transportation services regulated by the FERC also operate under approved tariff rates. ANR Pipeline'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 natural gas pipeline 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 and its customers reached a rate case settlement in November 2007 that was approved by the FERC in January 2008. GTN's financial results in 2007 reflected the terms of the settlement. In 2008, the GTN System refunded 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 was established during 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 certifying 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 rates currently in effect. The settlement expired October 31, 2005, with no requirement to file for new rates at any time, nor is Great Lakes prohibited from filing such a rate case. Great Lakes' services are provided pursuant to its FERC-approved tariff, which includes, among other factors, maximum and minimum rate levels for services and permits Great Lakes to negotiate or discount rates on a non-discriminatory basis.

Portland
In April 2008, Portland filed a general rate case under the *Natural Gas Act of 1938*, in accordance with the terms of its previous settlement approved by the FERC in 2003. The proposed tariffs, which included a rate increase of approximately six per cent, became effective September 1, 2008, subject to refund, in accordance with a FERC order dated May 1, 2008. The rate case hearing is scheduled to begin in July 2009.

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. 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 is required to provide services under negotiated and discounted rates on a non-discriminatory basis.

Regulatory Assets and Liabilities

Year ended December 31 (millions of dollars)	**2008**	2007	Remaining Recovery/ Settlement Period
			(years)
Regulatory Assets			
Unrealized losses on derivatives[1]	**67**	106	1 - 5
Foreign exchange on long-term debt principal[2]	**32**	34	21
Deferred income tax on carrying costs capitalized during construction of utility plant[3]	**26**	20	n/a
Unamortized issue costs on Preferred Securities[4]	**18**	19	18
Phase II preliminary expenditures[5]	**16**	18	7
Transitional other benefit obligations[6]	**15**	16	8
Unamortized post-retirement benefits[7]	**11**	13	3 - 5
Operating and debt-service regulatory assets[8]	**–**	85	n/a
Other	**16**	25	n/a
Total Regulatory Assets (Other Assets)	**201**	336	
Regulatory Liabilities			
Operating and debt-service regulatory liabilities[8]	**234**	3	1
Foreign exchange gain on redemption of Preferred Securities, net of income tax of $10 million (2007 – $15 million)[4]	**101**	150	3
Foreign exchange on long-term debt[9]	**70**	266	4 - 21
Post-retirement benefits other than pension[10]	**58**	38	n/a
Unamortized gains on derivatives[1]	**24**	n/a	4
Fuel tracker[11]	**23**	29	n/a
Negative salvage[12]	**16**	17	n/a
Other	**25**	22	n/a
Total Regulatory Liabilities (Deferred Amounts)	**551**	525	

(1) Unrealized gains and losses on derivatives represent the net position of fair value gains and losses on cross-currency and interest-rate swaps, and forward foreign currency contracts, which act as economic hedges. The cross-currency swaps pertain to foreign debt instruments associated with the Canadian Mainline, Foothills and Alberta System. Pre-tax operating results would have been $63 million higher in 2008 (2007 – $22 million lower) if these amounts had not been recorded as regulatory assets and liabilities.

(2) The foreign exchange on long-term debt principal account in the Alberta System, as approved by the AUC, is designed to facilitate the recovery or refund of foreign exchange gains and losses over the life of the foreign currency debt issues. Realized gains and losses and estimated net future losses on foreign currency debt are amortized over the remaining years of the longest outstanding U.S. debt issue. The annual amortization amount is included in the determination of tolls for the year. Pre-tax operating results would have been $2 million lower in 2008 (2007 – $1 million higher) if these amounts had not been recorded as regulatory assets.

(3) Rate-regulated accounting allows the capitalization of both equity and interest components for the carrying costs of funds used during the construction of utility assets. The capitalized AFUDC is depreciated as part of the total depreciable plant after the utility assets are placed in service. Equity AFUDC is not subject to income taxes, therefore, a deferred tax provision is recorded with an offset to a corresponding regulatory asset.

(4) 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 current rate case settlement. In addition, the issue costs on the Preferred Securities will be amortized over 20 years beginning January 1, 2007. 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 if these amounts had not been recorded as regulatory assets. This would have (decreased)/increased 2008 pre-tax operating results by $(54) million and $1 million (2007 – $165 million and $(19) million) related to the foreign exchange gain and issue costs, respectively.

(5) Phase II preliminary expenditures are costs incurred by Foothills prior to 1981 related to development of Canadian facilities to deliver Alaskan gas. These costs have been approved by the regulator for collection through straight-line amortization over the period November 2002 to December 2015. Pre-tax operating results would have been $2 million higher in 2008 (2007 – $2 million higher) if these amounts had not been recorded as regulatory assets.

(6) The regulatory asset with respect to the annual transitional other benefit obligations is being amortized over 17 years to December 2016, at which time the full transitional obligation will have been recovered through tolls. Pre-tax operating results would have been $1 million higher in 2008 (2007 – $2 million higher) if these amounts had not been recorded as regulatory assets.

(7) An amount is recovered in ANR's rates for post-retirement benefits other than pensions (PBOP). A curtailment and special termination benefits charge related to PBOP for a closed group of retirees was recorded as a regulatory asset and is being amortized through 2011. Pre-tax operating results would have been $3 million higher in 2008 (2007 – $3 million higher) if these amounts had not been recorded as regulatory assets.

(8) Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances approved by the regulatory authority for inclusion in determining tolls for the immediate following calendar year. Pre-tax operating results would have been $316 million higher in 2008 (2007 – $152 million lower) if these amounts had not been recorded as regulatory assets and liabilities.

(9) Foreign exchange on long-term debt of the Canadian Mainline, Alberta System and Foothills represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the 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 PBOP. This regulatory liability represents the difference between the amount collected in rates and the amount of PBOP expense. No PBOP expense was recorded in 2008 and 2007.

(11) ANR's tariff stipulates a fuel tracker mechanism to track over- or under-collections of fuel used and gas lost and unaccounted for (collectively, fuel). The fuel tracker represents the difference between the value of 'in-kind' natural gas retained from shippers and the actual amount of natural gas used for fuel by ANR. Any over- or under-collections are returned to or collected from shippers through a prospective annual adjustment to fuel retention rates. A regulatory asset or liability is established for the difference between ANR's actual fuel use and amounts collected through its fuel rates. Pre-tax operating results are not affected by the fuel tracker mechanism.

(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.

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 at December 31, 2008, this method is also used for accounting purposes. Consequently, future income tax liabilities have not been recognized, as it is expected they will be recovered through future rates when the amounts become payable. 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 would have been recorded at December 31, 2008 and would have been recoverable from future revenues. 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. Effective January 1, 2009, the Company will be adopting policies consistent with FAS 71 to account for its rate-regulated pipelines, as discussed in Note 3.

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)	**2008**	2007
Non-controlling interest in PipeLines LP	**721**	539
Non-controlling interest in Portland	**84**	71
	805	610

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

Year ended December 31 (millions of dollars)	**2008**	2007	2006
Non-controlling interest in PipeLines LP	**62**	65	43
Non-controlling interest in Portland	**46**	10	13
	108	75	56

The non-controlling interests in PipeLines LP and Portland as at December 31, 2008 represented the 67.9 per cent and 38.3 per cent interest, respectively, not owned by TCPL (2007 – 67.9 per cent and 38.3 per cent, respectively).

TCPL received revenues of $2 million from PipeLines LP in 2008 (2007 – $2 million; 2006 – $1 million) and $7 million from Portland in 2008 (2007 – $7 million; 2006 – $6 million) for services it provided.

NOTE 16 PREFERRED SHARES

December 31	Number of Shares	Dividend Rate Per Share	Redemption Price Per Share	**2008**	2007
	(thousands)			(millions of dollars)	(millions of dollars)
Cumulative First Preferred Shares					
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 issuable in series is unlimited. All of the cumulative first preferred shares are without par value.

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

Dividend Reinvestment and Share Purchase Plan

Commencing in 2007, the Board of Directors of TransCanada authorized the issuance of common shares from treasury at a discount to participants in TransCanada's Dividend Reinvestment and Share Purchase Plan (DRP). Under the DRP, eligible TCPL preferred shareholders may reinvest their dividends and make optional cash payments to obtain additional TransCanada common shares. The discount was set at two per cent commencing with the dividend payable in April 2007 and was increased to three per cent for the dividend payable in January 2009. TransCanada reserves the right to alter the discount or return to purchasing shares on the open market at any time. Prior to the April 2007 dividend, TransCanada purchased shares on the open market and provided them to DRP participants at cost.

NOTE 17 COMMON SHARES

	Number of Shares	Amount
	(thousands)	(millions of dollars)
Outstanding at December 31, 2005 and 2006	483,344	4,712
Issued for cash or cash equivalent	48,205	1,842
Outstanding at December 31, 2007	531,549	6,554
Issued for cash or cash equivalent	66,341	2,419
Outstanding at December 31, 2008	**597,890**	**8,973**

Common Shares Issued and Outstanding
The Company is authorized to issue an unlimited number of common shares without par value.

Share Capital
In 2008, TCPL issued 66.3 million common shares to TransCanada for proceeds of approximately $2.4 billion.

In 2007, TCPL issued 48.2 million common shares to TransCanada for proceeds of approximately $1.8 billion.

Restriction on Dividends
Certain terms of the Company's preferred shares and debt instruments could restrict the company's ability to declare dividends on preferred and common shares. At December 31, 2008, approximately $1.7 billion (2007 – $1.5 billion) was available for the payment of dividends on common and preferred shares.

NOTE 18 RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

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

Risk management strategies, policies and limits are designed to ensure TCPL's risks and related exposures are in line with the Company's business objectives and risk tolerance. Risks are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by risk management and internal audit personnel. The Board of Directors' Audit Committee oversees how management monitors compliance with risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework. Internal audit personnel assist the Audit Committee in its oversight role by performing regular and ad-hoc reviews of risk management controls and procedures, the results of which are reported to the Audit Committee. The Board of Directors also has a Governance Committee that assists in overseeing the risk management activities of TCPL. The Governance Committee monitors, reviews with management and makes recommendations related to TCPL's risk management programs and policies on an ongoing basis.

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

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

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

Commodity Price Risk

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

- Subject to the Company's overall risk management policies, the Company commits a significant portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to mitigate price risk in its asset portfolio.
- The Company purchases a portion of the natural gas and oil products required for its power plants or enters into contracts that base the sales price of electricity on the cost of natural gas, effectively locking in a margin. A significant portion of the electricity needed to fulfill the Company's power sales commitments is purchased with contracts or fulfilled through power generation, thereby reducing the Company's exposure to fluctuating commodity prices.
- The Company enters into offsetting or back-to-back positions and derivative financial instruments to manage price risk exposure in power and natural gas commodities created by certain fixed and variable pricing arrangements for different pricing indices and delivery points.

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

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

Natural Gas Inventory Price Risk

At December 31, 2008, $76 million (2007 – $190 million) of proprietary natural gas inventory was included in Inventories. Effective April 2007, TCPL began valuing its proprietary natural gas inventory held in storage at fair value, as measured by the one-month forward price for natural gas less selling costs. The Company did not have any proprietary natural gas inventory held in storage prior to April 2007. In 2008, the net change in fair value of proprietary natural gas held in inventory was a net unrealized loss of $7 million (2007 – nil), which was recorded as a decrease to Revenue and Inventory. In 2008, the net change in fair value of natural gas forward purchases and sales contracts was a net unrealized gain of $7 million (2007 – $10 million) which was included in Revenues.

Foreign Exchange and Interest Rate Risk

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

A portion of TCPL's earnings from its Pipelines and Energy operations is generated in U.S. dollars and is subject to currency fluctuations. The performance of the Canadian dollar relative to the U.S. dollar can affect TCPL's earnings. This foreign exchange impact is offset by certain related debt and financing costs being denominated in U.S. dollars and by the Company's hedging activities. Due to its increased U.S. operations, TCPL has a greater exposure to U.S. currency 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 debt and other U.S. dollar-denominated transactions, and to manage the interest rate exposure of the Canadian Mainline, Alberta System and Foothills operations. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms. These gains and losses are deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers in accordance with the terms of the shipping agreements.

TCPL 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 this risk.

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 foreign exchange contracts, cross-currency interest rate swaps and foreign exchange options. At December 31, 2008, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $7.2 billion (US$5.9 billion) (2007 – $4.3 billion (US$4.4 billion)) and a fair value of $5.9 billion (US$4.8 billion) (2007 – $4.4 billion (US$4.5 billion)). In January 2009, the Company issued an additional US$2.0 billion of long-term debt and designated it as a hedge of the net U.S. dollar investment in foreign operations. At December 31, 2008, $254 million was included in Deferred Amounts for the fair value of the forwards, swaps and options used to hedge the Company's net U.S. dollar investment in foreign operations.

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

Asset/(Liability)	**2008**		2007	
December 31 (millions of dollars)	**Fair Value**	**Notional or Principal Amount**	Fair Value	Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2009 to 2014)	**(218)**	**U.S. 1,650**	77	U.S. 350
U.S. dollar forward foreign exchange contracts (maturing 2009)	**(42)**	**U.S. 2,152**	(4)	U.S. 150
U.S. dollar options (maturing 2009)	**6**	**U.S. 300**	3	U.S. 600
	(254)	**U.S. 4,102**	76	U.S. 1,100

VaR Analysis

TCPL uses a Value-at-Risk (VaR) methodology 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 TCPL 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. The VaR methodology is a statistically-calculated, probability-based approach that takes into consideration market volatilities as well as risk diversification by recognizing offsetting positions and correlations among products and markets. Risks are measured across all products and markets, and risk measures are aggregated to arrive at a single VaR number.

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

TCPL'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. 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. TCPL's consolidated VaR was $23 million at December 31, 2008 (2007 – $8 million). The increase from December 31, 2007 was primarily due to the Ravenswood acquisition.

Counterparty Credit Risk

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

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

TCPL's maximum counterparty credit exposure with respect to financial instruments at the balance sheet date consisted primarily of the carrying amount, which approximates fair value, of non-derivative financial assets, such as accounts receivable, as well as the fair value of derivative financial assets.

The Company does not have significant concentrations of counterparty credit risk with any individual counterparties and the majority of counterparty credit exposure is with counterparties who are investment grade. At December 31, 2008, there were no significant amounts past due or impaired.

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

During the deterioration of global financial markets in 2008, TCPL continued to closely monitor and reassess the creditworthiness of its counterparties, including financial institutions. This has resulted in TCPL reducing or mitigating its exposure to certain counterparties where it is deemed warranted and permitted under contractual terms. As part of its ongoing operations, TCPL must balance its market risk and counterparty credit risk when making business decisions.

Certain subsidiaries of Calpine Corporation (Calpine) filed for bankruptcy protection in both Canada and the U.S. in 2005. Gas Transmission Northwest Corporation (GTNC) and Portland Natural Gas Transmission System (PNGTS) reached agreements with Calpine for allowed unsecured claims in the Calpine bankruptcy. In February 2008, GTNC and PNGTS received initial distributions of 9.4 million common shares and 6.1 million common shares of Calpine, respectively, which represented approximately 85 per cent of their agreed upon claims. In 2008, these shares were subsequently sold into the open market and resulted in total pre-tax gains of $279 million. Claims by NGTL and Foothills Pipe Lines (South B.C.) Ltd. for $32 million and $44 million, respectively, were received in cash in January 2008 and will be passed on to shippers on these systems. At December 31, 2008, $22 million remained in regulatory liabilities for these claims.

Liquidity Risk

Liquidity risk is the risk that TCPL 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, under both normal and stressed conditions, it always has sufficient cash and credit facilities to meet its obligations when due, without incurring unacceptable losses or damage to the Company's reputation.

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

At December 31, 2008, the Company had committed revolving bank lines of US$1.0 billion, $2.0 billion and US$300 million maturing in November 2010, December 2012 and February 2013, respectively. As of December 31, 2008, no draws were made on these facilities as the Company has continued to have largely uninterrupted access to the Canadian commercial paper market on competitive terms. In January 2009, TCPL filed a new US$3.0 billion debt shelf in the U.S. to supplement the $1.8 billion and $1.0 billion of capacity available under its existing equity and Canadian debt shelves, respectively. The Company has US$1.0 billion of capacity remaining available under its January 2009 U.S. debt shelf.

The following tables detail the remaining contractual maturities for TCPL's non-derivative financial liabilities, including both the principal and interest cash flows at December 31, 2008:

Contractual Repayments of Financial Liabilities[1]

		Payments Due by Period			
(millions of dollars)	Total	2009	2010 and 2011	2012 and 2013	2014 and Thereafter
Notes payable	1,702	1,702	–	–	–
Due to TransCanada Corporation	1,821	1,821	–	–	–
Long-term debt and junior subordinated notes	17,367	786	1,545	2,550	12,486
Long-term debt of joint ventures	1,076	207	270	172	427
Total contractual repayments	21,966	4,516	1,815	2,722	12,913

(1) The anticipated timing of settlement of derivative contracts is presented in the Derivatives Financial Instrument Summary in this Note.

Interest Payments on Financial Liabilities

		Payments Due by Period			
(millions of dollars)	Total	2009	2010 and 2011	2012 and 2013	2014 and Thereafter
Due to TransCanada Corporation	92	92	–	–	–
Long-term debt and junior subordinated notes	15,170	1,150	2,151	1,950	9,919
Long-term debt of joint ventures	328	61	76	56	135
Total interest payments	15,590	1,303	2,227	2,006	10,054

Capital Management

The primary objective of capital management is to ensure TCPL has strong credit ratings to support its businesses and maximize shareholder value. In 2008, this overall objective and policy for managing capital remained unchanged from the prior year.

TCPL 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, net amounts Due to TransCanada Corporation, Long-Term Debt and Junior Subordinated Notes less Cash and Cash Equivalents. Net debt only includes obligations that the Company controls and manages. Consequently, it does not include Cash and Cash Equivalents, Notes Payable and Long-Term Debt of TCPL's joint ventures.

The capital structure at December 31 was as follows:

(millions of dollars)	**2008**	2007
Notes payable	**1,685**	41
Due to TransCanada Corporation, net	**292**	472
Long-term debt	**16,154**	12,933
Junior subordinated notes	**1,213**	975
Cash and cash equivalents	**(1,109)**	(333)
Net debt	**18,235**	14,088
Non-controlling interests	**805**	610
Shareholders' equity	**12,963**	10,053
Total equity	**13,768**	10,663
Total capital	**32,003**	24,751

Fair Values

The fair value of financial instruments included in Cash and Cash Equivalents, Accounts Receivable, Other Assets, Notes Payable, Accounts Payable, Accrued Interest and Deferred Amounts approximates their carrying amounts due to the nature of the item and/or the short time to maturity. The fair value of foreign exchange and interest rate derivatives has been calculated using year-end market rates. The fair value of power, natural gas and oil products derivatives has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes are used. Credit risk has been taken into consideration when calculating fair values.

Valuation techniques that refer to observable market data or estimated market prices may also be used to calculate fair value. 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, was estimated by discounting future payments of interest and principal at estimated interest rates that were made available to the Company.

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 follows:

	2008		2007	
December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Long-Term Debt				
TransCanada PipeLines Limited[1]	**11,389**	**10,583**	8,519	9,400
NOVA Gas Transmission Ltd.	**1,437**	**1,534**	1,508	1,877
TransCanada PipeLine USA Ltd.	**857**	**857**	850	850
ANR Pipeline Company	**541**	**570**	435	573
Gas Transmission Northwest Corporation	**488**	**393**	399	383
TC PipeLines, LP	**580**	**580**	499	499
Great Lakes Gas Transmission Limited Partnership	**526**	**496**	434	519
Tuscarora Gas Transmission Company	**78**	**80**	67	81
Portland Natural Gas Transmission System	**236**	**220**	205	214
Other	**22**	**24**	17	24
	16,154	**15,337**	12,933	14,420
Junior Subordinated Notes	**1,213**	**815**	975	914
	17,367	**16,152**	13,908	15,334
Long-Term Debt of Joint Ventures				
Northern Border Pipeline Company	**391**	**391**	311	329
Iroquois Gas Transmission System, L.P.	**195**	**181**	169	180
Bruce Power L.P. and Bruce Power A L.P.	**330**	**318**	243	243
Trans Québec & Maritimes Pipeline Inc.	**155**	**157**	165	169
Other	**5**	**5**	15	16
	1,076	**1,052**	903	937
	18,443	**17,204**	14,811	16,271

(1) At December 31, 2008, the carrying amount of Long-Term Debt included $15 million (2007 – $15 million) for fair value adjustments related to swap agreements on $50 million (2007 – $150 million) and US$200 million (2007 – US$200 million) of this debt.

Non-Derivative Financial Instruments Summary

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

	2008		2007	
December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial Assets[1]				
Cash and cash equivalents	**1,300**	**1,300**	504	504
Accounts receivable and other assets[2][3]	**1,404**	**1,404**	1,231	1,231
Due from TransCanada Corporation	**1,529**	**1,529**	1,407	1,407
Available-for-sale assets[2]	**27**	**27**	17	17
	4,260	**4,260**	3,159	3,159
Financial Liabilities[1][3]				
Notes payable	**1,702**	**1,702**	55	55
Accounts payable and deferred amounts[4]	**1,364**	**1,364**	1,192	1,192
Accrued interest	**361**	**361**	265	265
Due to TransCanada Corporation	**1,821**	**1,821**	1,879	1,879
Long-term debt and junior subordinated notes	**17,367**	**16,152**	13,908	15,334
Long-term debt of joint ventures	**1,076**	**1,052**	903	937
Other long-term liabilities of joint ventures[4]	**–**	**–**	60	60
	23,691	**22,452**	18,262	19,722

(1) Consolidated Net Income in 2008 and 2007 included unrealized gains or losses of nil for the fair value adjustments to each of these financial instruments.

(2) At December 31, 2008, the Consolidated Balance Sheet included financial assets of $1,257 million (2007 – $1,018 million) in Accounts Receivable and $174 million (2007 – $230 million) in Other Assets.

(3) Recorded at amortized cost, except for certain Long-Term Debt which is adjusted to fair value.

(4) At December 31, 2008, the Consolidated Balance Sheet included financial liabilities of $1,342 million (2007 – $1,174 million) in Accounts Payable and $22 million (2007 – $78 million) in Deferred Amounts.

Derivative Financial Instruments Summary
Information for the Company's derivative financial instruments is as follows:

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

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

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

(3) All power, natural gas and oil products realized and unrealized gains and losses are included in Revenues. All interest rate and foreign exchange realized and unrealized gains and losses are included in Financial Charges and Interest Income and Other, respectively. Realized gains and losses are included in Net Income upon settlement of the financial instrument.

(4) All hedging relationships are designated as cash flow hedges except for interest-rate derivative financial instruments designated as fair value hedges with a fair value of $8 million. In 2008, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

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

The anticipated timing of settlement of the derivative contracts assumes no changes in commodity prices, interest rates and foreign exchange rates from December 31, 2008. Actual settlements will vary based on changes in these factors. The anticipated timing of settlement of these contracts is as follows:

(millions of dollars)	Total	2009	2010 and 2011	2012 and 2013	2014 and Thereafter
Derivative financial instruments held for trading	(30)	38	(46)	(14)	(8)
Derivative financial instruments in hedging relationships	(199)	(68)	(65)	(43)	(23)
	(229)	(30)	(111)	(57)	(31)

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	–
Net unrealized gains/(losses) in the year(3)	$16	$(10)	$8	$(5)
Net realized(losses)/gains in the year(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	–
Net realized (losses)/gains in the year(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 power and natural gas realized and unrealized gains and losses are included in Revenues. All interest rate and foreign exchange realized and unrealized gains and losses are included in Financial Charges and Interest Income and Other, respectively. Realized gains and losses are included in Net Income upon settlement of the financial instrument.

(4) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $2 million. In 2007, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(5) In 2007, Net Income 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. In 2007, Net Income 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 when the anticipated transaction was not likely to occur by the end of the originally specified time period.

Balance Sheet Presentation of Derivative Financial Instruments

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

December 31 (millions of dollars)	**2008**	2007
Current		
Other current assets	**318**	160
Accounts payable	**(298)**	(144)
Long-term		
Other assets	**191**	204
Deferred amounts	**(694)**	(205)

Derivative Financial Instruments of Joint Ventures

Included in the Balance Sheet Presentation of Derivative Financial Instruments table above are amounts related to power derivatives used by one of the Company's joint ventures to manage commodity price risk. The Company's proportionate share of the fair value of these power sales derivatives was $75 million at December 31, 2008 (2007 – $75 million). These contracts mature from 2009 to 2014. The Company's proportionate share of the notional sales volumes of power associated with this exposure was 7,600 gigawatt hours (GWh) at December 31, 2008 (2007 – 7,300 GWh). The Company's proportionate share of the notional purchased volumes of power associated with this exposure was 47 GWh at December 31, 2008 (2007 – 50 GWh).

NOTE 19 INCOME TAXES

Provision for Income Taxes

Year ended December 31 (millions of dollars)	**2008**	2007	2006
Current			
Canada	**381**	364	263
Foreign	**143**	65	37
	524	429	300
Future			
Canada	**(10)**	8	104
Foreign	**77**	46	71
	67	54	175
	591	483	475

Geographic Components of Income

Year ended December 31 (millions of dollars)	**2008**	2007	2006
Canada	**1,203**	1,208	1,158
Foreign	**938**	582	444
Income from continuing operations before income taxes and non-controlling interests	**2,141**	1,790	1,602

Reconciliation of Income Tax Expense

Year ended December 31 (millions of dollars)	**2008**	2007	2006
Income from continuing operations before income taxes and non-controlling interests	**2,141**	1,790	1,602
Federal and provincial statutory tax rate	**29.5%**	32.1%	32.5%
Expected income tax expense	**632**	575	521
Income tax differential related to regulated operations	**44**	69	72
Lower effective foreign tax rates	**(5)**	(39)	n/a
Tax rate and legislated changes	**–**	(73)	(33)
Income from equity investments and non-controlling interests	**(45)**	(34)	(27)
Change in valuation allowance	**(9)**	–	–
Other[1]	**(26)**	(15)	(58)
Actual income tax expense	**591**	483	475

[1] Includes net income tax benefits of $7 million recorded in 2008 (2007 – $13 million; 2006 – $51 million) on the resolution of certain income tax matters with taxation authorities and changes in estimates.

Future Income Tax Assets and Liabilities

December 31 (millions of dollars)	**2008**	2007
Deferred amounts	**119**	43
Other post-employment benefits	**69**	57
Unrealized losses on derivatives	**62**	22
Unrealized foreign exchange losses on long-term debt	**77**	n/a
Non-capital loss carryforwards	**24**	n/a
Other	**107**	63
	458	185
Less: valuation allowance[1]	**77**	13
Future income tax assets, net of valuation allowance	**381**	172
Difference in accounting and tax bases of plant, equipment and PPAs	**1,464**	1,073
Investments in subsidiaries and partnerships	**28**	61
Pension benefits	**55**	50
Unrealized foreign exchange gains on long-term debt	**14**	110
Unrealized gains on derivatives	**19**	27
Other	**54**	44
Future income tax liabilities	**1,634**	1,365
Net future income tax liabilities	**1,253**	1,193

[1] A valuation allowance was recorded in 2008 as there is no virtual certainty that the Company will realize the tax benefit related to the unrealized foreign exchange losses on long-term debt in the future.

Unremitted Earnings of Foreign Investments
Income taxes have not been provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. Future income tax liabilities would have increased by approximately $102 million at December 31, 2008 (2007 – $72 million) if there had been a provision for these taxes.

Income Tax Payments
Income tax payments of $486 million were made during the year ended December 31, 2008 (2007 – $440 million; 2006 – $494 million).

NOTE 20 NOTES PAYABLE

	2008		2007	
	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	**1,250**	**1.8%**	55	5.0%
U.S. dollars (2008 – US$369)	**452**	**3.3%**	–	–
	1,702		55	

Notes payable consists of commercial paper outstanding and drawings on bridge and line-of-credit facilities. Unsecured revolving and demand credit facilities totaled $4.2 billion at December 31, 2008 to support the Company's commercial paper program and for general corporate purposes. These credit facilities included the following:

- a $2.0 billion committed, syndicated, revolving credit facility maturing December 2012, which was fully available at December 31, 2008. The cost to maintain the credit facility was $2 million in 2008 (2007 – $2 million).
- a US$300 million syndicated, revolving facility, maturing February 2013, which was fully available at December 31, 2008. This facility is part of the US$1.0 billion committed, unsecured TransCanada PipeLine USA Ltd. credit facility established in February 2007.
- a US$1.0 billion committed, extendible, expandable, revolving, unsecured, one-year agreement executed by TransCanada Keystone Pipeline L.P. in fourth quarter 2008 with a syndicate of banks, bearing interest at a floating rate, based on the greater of bank prime interest rates and LIBOR, plus a margin of not less than one per cent and not more than three per cent on revolving loans and not less than three per cent and not more than 6.5 per cent if drawn as a term loan. The agreement is extendible at the option of the Keystone partnership for an additional one-year term. As at December 31, 2008, this facility was fully available. This US$1.0 billion agreement is guaranteed by TCPL.
- demand lines totaling $611 million, which support the issuance of letters of credit and provide additional liquidity. The Company had used approximately $433 million of its total lines of credit for letters of credit at December 31, 2008. 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 June 2008, TCPL executed an agreement with a syndicate of banks for a US$1.5 billion, committed, unsecured, one-year bridge loan facility, at a floating interest rate based on LIBOR plus 30 basis points. The facility is extendible at the option of the Company for an additional six-month term at LIBOR plus 35 basis points. In August 2008, the Company used US$255 million from this facility and cancelled the remainder of the commitment. At December 31, 2008, US$255 million remained outstanding on the facility.

NOTE 21 ASSET RETIREMENT OBLIGATIONS

The estimated undiscounted cash flows required to settle the asset retirement obligations with respect to the regulated and non-regulated operations in the Pipelines segment were $69 million at December 31, 2008 (2007 – $65 million), calculated using an inflation rate ranging from two per cent to four per cent per annum. The estimated fair value of these liabilities was $31 million at December 31, 2008 (2007 – $25 million) after discounting the estimated cash flows at rates ranging from 5.4 per cent to 8.0 per cent. At December 31, 2008, the expected timing of payment for settlement of the obligations ranged from one year to 27 years. Management believes it is reasonable to assume that all retirement costs associated with its regulated pipelines will be recovered through future tolls and, therefore, typically only records asset retirement obligations for its non-regulated pipelines.

The estimated undiscounted cash flows required to settle the asset retirement obligations with respect to the Energy segment were $427 million at December 31, 2008 (2007 – $216 million), calculated using an inflation rate ranging from two per cent to three per cent per annum. The estimated fair value of this liability was $85 million at December 31, 2008 (2007 – $63 million), after discounting the estimated cash flows at rates ranging from 5.4 per cent to 8.0 per cent. At December 31, 2008, the expected timing of payment for settlement of the obligations ranged from 10 years to 33 years.

Reconciliation of Asset Retirement Obligations[1]

(millions of dollars)	Pipelines	Energy	Total
Balance at January 1, 2006	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
New obligations and revisions in estimated cash flows	**4**	**18**	**22**
Accretion expense	**2**	**4**	**6**
Balance at December 31, 2008	**31**	**85**	**116**

(1) At December 31, 2008, Asset Retirement Obligations totalling $114 million (2007 – $88 million) and $2 million (2007 – nil) were included in Deferred Amounts and Accounts Payable, respectively.

NOTE 22 EMPLOYEE FUTURE BENEFITS

The Company sponsors DB Plans that cover substantially all employees. Pension benefits provided under the DB Plans are based on years of service and highest average earnings over three consecutive years of employment, and increase annually in the Canadian pension plan by a portion of the increase in the Consumer Price Index (CPI). Past service costs are amortized over the expected average remaining service life of employees, which is approximately nine years.

Effective January 1, 2008, the Company also provides its employees with a Savings Plan in Canada, a 401(k) Plan in the U.S. and post-employment benefits other than pensions, including termination benefits and defined life insurance and medical benefits beyond those provided by government-sponsored plans. Past service costs are amortized over the expected average remaining life expectancy of former employees, which was approximately 11 years at December 31, 2008. Contributions to the Savings Plan and 401(k) Plan are expensed as incurred.

Total cash payments for employee future benefits, consisting of cash contributed by the Company to the DB Plans and other benefit plans, was $90 million in 2008 (2007 – $61 million; 2006 – $104 million), including $21 million in 2008 (2007 – $8 million; 2006 – $2 million) related to retirement savings plans.

The Company measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2009, and the next required valuation will be as at January 1, 2010.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2008**	2007	**2008**	2007
Change in Benefit Obligation				
Benefit obligation – beginning of year	**1,462**	1,378	**155**	132
Current service cost	**52**	45	**2**	2
Interest cost	**80**	73	**8**	7
Employee contributions	**3**	4	**1**	–
Benefits paid	**(68)**	(65)	**(8)**	(7)
Actuarial (gain)/loss	**(261)**	(22)	**(21)**	8
Foreign exchange rate changes	**35**	(16)	**10**	(6)
Plan amendment	**–**	–	**(11)**	–
Acquisition	**29**	65	**8**	19
Benefit obligation – end of year	**1,332**	1,462	**144**	155
Change in Plan Assets				
Plan assets at fair value – beginning of year	**1,358**	1,264	**30**	33
Actual return on plan assets	**(222)**	33	**(10)**	2
Employer contributions	**62**	46	**7**	7
Employee contributions	**3**	4	**1**	–
Benefits paid	**(68)**	(65)	**(8)**	(7)
Foreign exchange rate changes	**32**	(17)	**6**	(5)
Acquisition	**28**	93	**–**	–
Plan assets at fair value – end of year	**1,193**	1,358	**26**	30
Funded status – plan deficit	**(139)**	(104)	**(118)**	(125)
Unamortized net actuarial loss	**340**	299	**33**	44
Unamortized past service costs	**25**	28	**(1)**	7
Accrued benefit asset/(liability), net of valuation allowance of nil	**226**	223	**(86)**	(74)

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)	**2008**	2007	**2008**	2007
Other Assets	**226**	223	**–**	5
Deferred Amounts	**–**	–	**(86)**	(79)
Total	**226**	223	**(86)**	(74)

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)	**2008**	2007	**2008**	2007
Benefit obligation	**(1,317)**	(1,324)	**(144)**	(155)
Plan assets at fair value	**1,178**	1,198	**26**	30
Funded status – plan deficit	**(139)**	(126)	**(118)**	(125)

The Company's expected contributions in 2009 are approximately $140 million for the pension benefit plans and approximately $27 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
2009	77	8
2010	81	9
2011	84	9
2012	88	10
2013	91	10
2014 to 2018	510	59

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

	Pension Benefit Plans		Other Benefit Plans	
	2008	2007	**2008**	2007
Discount rate	**6.65%**	5.30%	**6.50%**	5.50%
Rate of compensation increase	**3.65%**	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 follows:

	Pension Benefit Plans			Other Benefit Plans		
	2008	2007	2006	**2008**	2007	2006
Discount rate	**5.30%**	5.05%	5.00%	**5.50%**	5.20%	5.15%
Expected long-term rate of return on plan assets	**6.95%**	6.90%	6.90%	**7.75%**	7.75%	7.75%
Rate of compensation increase	**3.60%**	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 determining the overall expected rate of return. The discount rate is based on market interest rates of high quality bonds that match the timing and benefits expected to be paid under each plan.

A nine per cent annual rate of increase in the per-capita cost of covered health care benefits was assumed for 2009 measurement purposes. The rate was assumed to decrease gradually to five per cent in 2018 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	11	(10)

The Company's net benefit cost is as follows:

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31 (millions of dollars)	**2008**	2007	2006	**2008**	2007	2006
Current service cost	**52**	45	39	**2**	2	3
Interest cost	**80**	73	65	**8**	7	8
Actual return on plan assets	**222**	(33)	(134)	**10**	(2)	(6)
Actuarial (gain)/loss	**(261)**	(22)	53	**(21)**	8	(2)
Plan amendment	**–**	–	–	**(11)**	–	(18)
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**93**	63	23	**(12)**	15	(15)
Difference between expected and actual return on plan assets	**(316)**	(51)	63	**(12)**	(1)	4
Difference between actuarial loss/(gain) recognized and actual actuarial loss/(gain) on accrued benefit obligation	**280**	47	(27)	**23**	(7)	4
Difference between amortization of past service costs and actual plan amendments	**4**	4	4	**11**	–	19
Amortization of transitional obligation related to regulated business	**–**	–	–	**2**	2	2
Net benefit cost recognized	**61**	63	63	**12**	9	14

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

December 31	Percentage of Plan Assets		**Target Allocations**
Asset Category	**2008**	2007	**2008**
Debt securities	**48%**	42%	**35% to 60%**
Equity securities	**52%**	58%	**40% to 65%**
	100%	100%	

Debt securities included the Company's debt of $3 million (0.3 per cent of total plan assets) and $4 million (0.3 per cent of total plan assets) at December 31, 2008 and 2007, respectively. Equity securities included the Company's common shares of $4 million (0.3 per cent of total plan assets) and $6 million (0.4 per cent of total plan assets) at December 31, 2008 and 2007, 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 TCPL. The following amounts in this note, including those in the accompanying tables, represent TCPL'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 $42 million in 2008 (2007 – $34 million; 2006 – $25 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, 2009, and the next required valuations will be as at January 1, 2010.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2008**	2007	**2008**	2007
Change in Benefit Obligation				
Benefit obligation – beginning of year	**789**	807	**165**	169
Current service cost	**27**	28	**8**	10
Interest cost	**42**	40	**9**	8
Employee contributions	**6**	5	**–**	–
Benefits paid	**(37)**	(23)	**(4)**	(2)
Actuarial gain	**(229)**	(34)	**(45)**	(16)
Foreign exchange rate changes	**1**	(3)	**–**	–
Acquisition	**–**	(31)	**–**	(2)
Plan amendment	**–**	–	**–**	(2)
Benefit obligation – end of year	**599**	789	**133**	165
Change in Plan Assets				
Plan assets at fair value – beginning of year	**626**	666	**–**	–
Actual return on plan assets	**(78)**	(1)	**–**	–
Employer contributions	**38**	32	**4**	2
Employee contributions	**6**	5	**–**	–
Benefits paid	**(37)**	(23)	**(4)**	(2)
Foreign exchange rate changes	**1**	(5)	**–**	–
Acquisition	**–**	(48)	**–**	–
Plan assets at fair value – end of year	**556**	626	**–**	–
Funded status – plan deficit	**(43)**	(163)	**(133)**	(165)
Unamortized net actuarial loss/(gain)	**51**	169	**(3)**	45
Unamortized past service costs	**–**	–	**3**	3
Accrued benefit asset/(liability), net of valuation allowance of nil	**8**	6	**(133)**	(117)

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)	**2008**	2007	**2008**	2007
Other Assets	**8**	6	**–**	–
Deferred Amounts	**–**	–	**(133)**	(117)
Total	**8**	6	**(133)**	(117)

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)	**2008**	2007	**2008**	2007
Benefit obligation	**(594)**	(786)	**(133)**	(165)
Plan assets at fair value	**551**	623	**–**	–
Funded status – plan deficit	**(43)**	(163)	**(133)**	(165)

The expected total contributions of the Company's joint ventures in 2009 are approximately $37 million for the pension benefit plans and approximately $4 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
2009	39	4
2010	43	5
2011	46	6
2012	50	7
2013	54	7
2014 to 2018	325	49

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

	Pension Benefit Plans		Other Benefit Plans	
	2008	2007	**2008**	2007
Discount rate	**6.70%**	5.25%	**6.40%**	5.15%
Rate of compensation increase	**3.50%**	3.50%		

The significant weighted average actuarial assumptions adopted in measuring the net benefit plan costs of the Company's joint ventures for years ended December 31 were as follows:

	Pension Benefit Plans			Other Benefit Plans		
	2008	2007	2006	**2008**	2007	2006
Discount rate	**5.25%**	5.00%	5.25%	**5.15%**	4.90%	5.15%
Expected long-term rate of return on plan assets	**7.00%**	7.00%	7.30%			
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	3	(2)
Effect on post-employment benefit obligation	17	(14)

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)	**2008**	2007	2006	**2008**	2007	2006
Current service cost	**27**	28	24	**8**	10	7
Interest cost	**42**	40	37	**9**	8	5
Actual return on plan assets	**78**	1	(68)	**–**	–	–
Actuarial (gain)/loss	**(229)**	(34)	77	**(45)**	(16)	72
Plan amendment	**–**	–	–	**–**	(2)	6
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**(82)**	35	70	**(28)**	–	90
Difference between expected and actual return on plan assets	**(122)**	(44)	26	**–**	–	–
Difference between actuarial loss/(gain) recognized and actual actuarial loss/(gain) on accrued benefit obligation	**239**	44	(70)	**48**	20	(72)
Difference between amortization of past service costs and actual plan amendments	**–**	–	–	**–**	3	(6)
Net benefit cost recognized related to joint ventures	**35**	35	26	**20**	23	12

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

December 31	Percentage of Plan Assets		Target Allocations
Asset Category	**2008**	2007	**2008**
Debt securities	**44%**	43%	**40%**
Equity securities	**56%**	57%	**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, 2008 and 2007, respectively. Equity securities included the Company's common shares of $3 million (0.6 per cent of total plan assets) and $3 million (0.5 per cent of total plan assets) at December 31, 2008 and 2007, respectively.

The assets of the pension plans are managed on a going concern basis subject to legislative restrictions. The plans' investment policies are to maximize returns within an acceptable risk tolerance. Pension assets are invested in a diversified manner with consideration given to the demographics of the plans' participants.

NOTE 23 CHANGES IN OPERATING WORKING CAPITAL

Year ended December 31 (millions of dollars)	**2008**	2007	2006
(Increase)/decrease in accounts receivable	**(126)**	49	(186)
Decrease/(increase) in inventories	**82**	(6)	(108)
(Increase)/decrease in other current assets	**(146)**	118	(6)
(Decrease)/increase in accounts payable	**(100)**	64	(41)
Increase/(decrease) in accrued interest	**102**	(10)	41
	(188)	215	(300)

NOTE 24 COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

Operating leases

Future annual payments, net of sub-lease receipts, under the Company's operating leases for various premises, services and equipment are approximately as follows:

Year ended December 31 (millions of dollars)	Minimum Lease Payments	Amounts Recoverable under Sub-leases	Net Payments
2009	40	(12)	28
2010	39	(12)	27
2011	39	(10)	29
2012	38	(5)	33
2013	37	(4)	33
2014 and thereafter	260	(7)	253
Total	453	(50)	403

The operating lease agreements for premises, services and equipment expire at various dates through 2035, with an option to renew certain lease agreements for periods of one year to ten years. Net rental expense on operating leases in 2008 was $52 million (2007 – $34 million; 2006 – $25 million).

TCPL's commitments under the acquired Alberta PPAs are considered to be operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Future payments under these PPAs have been excluded from the above table, as these payments are dependent upon plant availability, among other factors. The amount of power purchased under the PPAs in 2008 was $471 million (2007 – $440 million; 2006 – $499 million). The generating capacities and expiry dates of the PPAs are as follows:

	Megawatts	Expiry Date
Sundance A	560	December 31, 2017
Sundance B	353	December 31, 2020
Sheerness	756	December 31, 2020

TCPL 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. TCPL's share of these signed commitments, which extend over the three-year period ending December 31, 2011, are as follows:

Year ended December 31 (millions of dollars)	
2009	204
2010	49
2011	2
	255

Loan – Aboriginal Pipeline Group
On June 18, 2003, the Mackenzie Delta gas producers, the APG and TCPL reached an agreement governing TCPL's role in the Mackenzie Gas Pipeline (MGP) project. The project would result in a natural gas pipeline being constructed from Inuvik, Northwest Territories, to the northern border of Alberta, where it would connect with the Alberta System. Under the agreement, TCPL agreed to finance the APG for its one-third share of project pre-development costs. These costs, on a cumulative basis, are currently forecast to be between $150 million and $200 million, depending upon the pace of project development. As at December 31, 2008, the Company had advanced $140 million to the APG.

TCPL and the other co-venture companies involved in the MGP continue to pursue approval of the proposed project, focusing on obtaining regulatory approval and the Canadian government's support of an acceptable fiscal framework. Detailed discussions with the Canadian government are continuing, and project timing continues to be uncertain. In the event the co-venture group is unable to reach an agreement with the government on an acceptable fiscal framework, the parties will need to determine the appropriate next steps for the project, including a review by TCPL of the carrying value of advances to the APG.

Other Commitments
TCPL is committed to capital expenditures totalling approximately $2.3 billion related to its share of the construction costs of Keystone, North Central Corridor and other pipeline projects.

The Company is committed to capital expenditures totalling approximately $1.0 billion related to its share of the construction costs of Coolidge, Bruce Power, the remaining Cartier Wind projects, Halton Hills and Portlands Energy.

Contingencies
On April 3, 2008, the Ontario Court of Appeal dismissed an appeal filed by the Canadian Alliance of Pipeline Landowners' Associations (CAPLA). CAPLA filed the appeal as a result of a decision by the Ontario Superior Court in November 2006 to dismiss CAPLA's class action lawsuit against TCPL and Enbridge Inc. for damages 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*. The Ontario Court of Appeal's decision is final and binding as CAPLA did not seek any further appeal within the time frame allowed.

TCPL is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2008, the Company accrued approximately $83 million related to operating facilities and $3 million related to discontinued operation sites. The accrued amount represents the Company's estimate of the amount it expects to expend to remediate the sites. However, additional liabilities may be incurred as assessments occur and remediation efforts continue.

TCPL 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
TCPL, Cameco Corporation and BPC Generation Infrastructure Trust (BPC) have severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, operator licenses, a lease agreement and contractor services. The guarantees have terms

ranging from one year ending in 2010 to perpetuity. In addition, TCPL and BPC have severally guaranteed one-half of certain contingent financial obligations related to an agreement with the Ontario Power Authority to refurbish and restart Bruce A power generation units. The guarantees were provided as part of the reorganization of Bruce Power in 2005 and have terms ending in 2019. TCPL's share of the potential exposure under these Bruce A and Bruce B guarantees was estimated at December 31, 2008 to range from $711 million to a maximum of $750 million. The fair value of these guarantees is estimated to be $17 million.

The Company and its partners in certain jointly owned entities have severally as well as jointly and severally guaranteed the financial performance of these entities related primarily to construction projects, redelivery of natural gas, PPA payments and the payment of liabilities. TCPL's share of the potential exposure under these guarantees was estimated at December 31, 2008 to range from $688 million to a maximum of $1.4 billion. For certain of these entities, any payments made by TCPL under these guarantees in excess of its ownership interest are to be reimbursed by its partners. Deferred Amounts includes $9 million for the fair value of these joint and several guarantees.

TCPL has guaranteed a subsidiary's equity undertaking to support the payment, under certain conditions, of principal and interest on US$43 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, TCPL 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 TCPL under this agreement would 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 TCPL. The debt matures in 2010. The Company has made no provision related to this guarantee.

NOTE 25 RELATED PARTY TRANSACTIONS

The following amounts are included in Due from TransCanada Corporation:

		2008		2007	
(millions of dollars)	Maturity Dates	**Outstanding December 31**	**Interest Rate**	Outstanding December 31	Interest Rate
Discount Notes	2009	**1,529**	**2.1%**	1,226	4.8%
Promissory Notes[(1)]		**–**		181	
		1,529		1,407	

[(1)] Payable on demand and non-interest bearing.

The following amounts are included in Due to TransCanada Corporation:

		2008		2007	
(millions of dollars)	Maturity Dates	**Outstanding December 31**	**Interest Rate**	Outstanding December 31	Interest Rate
Credit Facility[(1)]	2009	**1,621**	**5.3%**	1,307	5.5%
Credit Facility[(2)]		**200**	**4.8%**	207	6.0%
Promissory Notes (2007 – US$370)[(3)]		**–**	**–**	365	5.6%
		1,821		1,879	

[(1)] TransCanada established a $2.5 billion, unsecured credit facility agreement with TCPL, bearing interest at the Reuters prime rate or Bankers' Acceptance rate plus 65 basis points, at TCPL's option. The funds advanced under this agreement can be used to repay indebtedness or to make partner contributions to Bruce A, or for working capital and general corporate purposes. At December 31, 2008, $1.6 billion was outstanding under this credit facility (2007 – $1.3 billion). This credit agreement matures on December 15, 2009.

[(2)] In May 2003, TCPL established a demand revolving credit facility with TransCanada for general corporate purposes at $500 million, or a U.S. dollar equivalent amount, bearing interest at the Royal Bank of Canada prime rate per annum or the U.S. base rate per annum. In May 2008, $7 million was repaid to TransCanada.

[(3)] In February 2007, TCPL issued a promissory note to TransCanada for US$700 million bearing interest at LIBOR plus 32.5 basis points, due on or before February 9, 2008. The US$370 million outstanding at December 31, 2007 was fully repaid on January 7, 2008.

In 2008, Financial Charges included $76 million (2007 – $72 million) of interest expense and $55 million (2007 – $30 million) of interest income as a result of transactions with TransCanada. At December 31, 2008, Accounts Payable included $2 million of interest payable to TransCanada (2007 – $5 million).

NOTE 26 DISCONTINUED OPERATIONS

The $28 million income from discontinued operations in 2006 reflected settlements received from bankruptcy claims related to TCPL's Gas Marketing business, which was sold in 2001.

NINE-YEAR FINANCIAL HIGHLIGHTS

(millions of dollars except where indicated)	**2008**	2007	2006	2005	2004	2003	2002	2001	2000
Income Statement									
Revenues	**8,619**	8,828	7,520	6,124	5,497	5,636	5,225	5,285	4,384
Net income from continuing operations	**1,442**	1,232	1,071	1,230	1,000	823	769	708	663
Net income/(loss) by segment									
Pipelines	**902**	686	560	679	584	625	639	572	613
Energy	**614**	514	452	566	398	217	160	181	95
Corporate	**(96)**	10	37	(37)	(4)	(41)	(52)	(67)	(80)
Continuing operations	**1,420**	1,210	1,049	1,208	978	801	747	686	628
Discontinued operations	**–**	–	28	–	52	50	–	(67)	61
Net income applicable to common shares	**1,420**	1,210	1,077	1,208	1,030	851	747	619	689
Cash Flow Statement									
Funds generated from operations	**2,992**	2,603	2,374	1,950	1,701	1,822	1,843	1,625	1,484
(Increase)/decrease in operating working capital	**(188)**	215	(300)	(48)	28	93	92	(487)	437
Net cash provided by operations	**2,804**	2,818	2,074	1,902	1,729	1,915	1,935	1,138	1,921
Capital expenditures and acquisitions	**(6,363)**	(5,874)	(2,042)	(2,071)	(2,046)	(965)	(851)	(1,082)	(1,144)
Disposition of assets, net of current income taxes	**28**	35	23	671	410	–	–	1,170	2,233
Cash dividends paid on common and preferred shares	**(817)**	(725)	(639)	(608)	(574)	(532)	(488)	(440)	(458)
Balance Sheet									
Assets									
Plant, property and equipment									
Pipelines	**20,700**	18,280	17,141	16,528	17,306	16,064	16,158	16,562	16,937
Energy	**8,435**	5,127	4,302	3,483	1,421	1,368	1,340	1,116	776
Corporate	**54**	45	44	27	37	50	64	66	111
Total assets									
Continuing operations	**40,935**	31,737	26,386	24,113	22,414	20,873	20,416	20,255	20,238
Discontinued operations	**–**	–	–	–	7	11	139	276	5,007
Total assets	**40,935**	31,737	26,386	24,113	22,421	20,884	20,555	20,531	25,245
Capitalization									
Long-term debt	**15,368**	12,377	10,887	9,640	9,749	9,516	8,899	9,444	10,008
Junior subordinated notes	**1,213**	975	–	–	–	–	–	–	–
Preferred securities	**–**	–	536	536	554	598	944	950	1,208
Non-controlling interests	**805**	610	366	394	311	324	288	286	257
Preferred shares	**389**	389	389	389	389	389	389	389	389
Common shareholders' equity	**12,574**	9,664	7,618	7,164	6,484	6,044	5,747	5,426	5,211

	2008	2007	2006	2005	2004	2003	2002	2001	2000
Per Common Share Data (dollars)									
Net income – Basic									
Continuing operations	**$2.59**	$2.33	$2.17	$2.50	$2.03	$1.66	$1.56	$1.44	$1.32
Discontinued operations	**–**	–	0.06	–	0.11	0.11	–	(0.14)	0.13
	$2.59	$2.33	$2.23	$2.50	$2.14	$1.77	$1.56	$1.30	$1.45
Net income – Diluted									
Continuing operations	**$2.59**	$2.33	$2.17	$2.50	$2.03	$1.66	$1.55	$1.44	$1.32
Discontinued operations	**–**	–	0.06	–	0.11	0.11	–	(0.14)	0.13
	$2.59	$2.33	$2.23	$2.50	$2.14	$1.77	$1.55	$1.30	$1.45
Per Preferred Share Data (dollars)									
Series U Cumulative First Preferred Shares	**$2.80**	$2.80	$2.80	$2.80	$2.80	$2.80	$2.80	$2.80	$2.80
Series Y Cumulative First Preferred Shares	**$2.80**	$2.80	$2.80	$2.80	$2.80	$2.80	$2.80	$2.80	$2.80
Financial Ratios									
Earnings to fixed charges[1]	**2.7**	2.6	2.6	2.9	2.5	2.3	2.3	2.1	1.9

[1] The earnings to fixed charges ratio is determined by dividing earnings by fixed charges. Earnings is calculated as the sum of income from continuing operations, financial charges, financial charges of joint ventures, income taxes, income from non-controlling interests (excluding non-controlling interests with financial charges) and adjusted for undistributed earnings of investments accounted for by the equity method. Fixed charges is calculated as the sum of financial charges, financial charges of joint ventures and capitalized interest.

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Chief Executive Officer

Russ Girling
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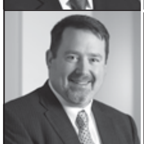

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