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The Management's Discussion and Analysis (MD&A) dated February 22, 2007 should be read in conjunction with the audited Consolidated Financial Statements of TransCanada Corporation (TransCanada or the Company) and the notes thereto for the year ended December 31, 2006. This MD&A covers TransCanada's financial position and operations as at and for the year ended December 31, 2006. TransCanada's February 22, 2007 acquisition of American Natural Resources Company, and ANR Storage Company (collectively ANR), additional interests in Great Lakes Gas Transmission Partnership (Great Lakes) and related events, are summarized in the "Subsequent Events" section of this MD&A. 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 2006 Annual Report.

CONSOLIDATED FINANCIAL REVIEW

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

	2006	2005	2004
Balance Sheet			
Total assets	**25,909**	24,113	22,422
Total long-term liabilities	**14,464**	13,012	12,403
Income Statement			
Revenues	**7,520**	6,124	5,497
Net income			
Continuing operations	**1,051**	1,209	980
Discontinued operations	**28**	–	52
Total net income	**1,079**	1,209	1,032
Per Common Share Data			
Net income – Basic			
Continuing operations	**$2.15**	$2.49	$2.02
Discontinued operations	**0.06**	–	0.11
	$2.21	$2.49	$2.13
Net income – Diluted			
Continuing operations	**$2.14**	$2.47	$2.01
Discontinued operations	**0.06**	–	0.11
	$2.20	$2.47	$2.12
Dividends declared	**$1.28**	$1.22	$1.16

(1) The selected three-year consolidated financial data is based on the Company's financial statements which are prepared in accordance with Canadian generally accepted accounting principles (GAAP). Certain comparative figures have been reclassified to conform with the current year's presentation.

HIGHLIGHTS

Balance Sheet

- In 2006, TransCanada's shareholders' equity increased by $0.5 billion to $7.7 billion.

Net Income

- In 2006, net income was $1,079 million or $2.21 per share compared to $1,209 million or $2.49 per share in 2005.

Net Earnings

- In 2006, TransCanada's net income from continuing operations (net earnings) was $1,051 million or $2.15 per share compared to $1,209 million or $2.49 per share in 2005.
- Excluding gains on sales of assets, TransCanada's net earnings increased $186 million in 2006 to $1,038 million or $2.12 per share compared to $852 million or $1.75 per share in 2005.

Investing Activities

- In 2006, TransCanada invested approximately $2.0 billion in its Pipelines and Energy businesses.
- In February 2007, the Company closed the acquisition of ANR and an additional 3.55 per cent interest in Great Lakes for approximately US$3.4 billion, subject to certain post-closing adjustments, including approximately US$488 million of assumed long-term debt.
- In February 2007, TC PipeLines, LP (PipeLines LP) closed its acquisition of a 46.45 per cent interest in Great Lakes for approximately US$962 million, subject to certain post-closing adjustments, including approximately US$212 million of assumed long-term debt.

Financing Activities

- In 2006, TransCanada issued $2.1 billion of long-term debt.
- In January 2007, the Company filed a short form shelf prospectus in Canada and the U.S. to allow for the offering of up to $3.0 billion of common shares, preferred shares and/or subscription receipts.
- In February 2007, the Company sold 39,470,000 subscription receipts at a price of $38.00 each. The gross proceeds of approximately $1.5 billion were used to partially finance the ANR acquisition. TransCanada granted the underwriters of the subscription receipts offering an option to purchase an additional 5,920,500 common shares at a price of $38.00 at any time up to and including March 16, 2007.
- In February 2007, the Company entered into agreements for a US$2.2 billion one-year bridge loan facility and, through a wholly owned subsidiary, for a new US$1.0 billion credit facility. The Company utilized $1.5 billion and US$1.8 billion from these and existing facilities to partially finance the ANR acquisition as well as additional interests in PipeLines LP, described below. A portion of these advances were repaid on February 23, 2007 with proceeds from the subscription receipt offering.
- In February 2007, PipeLines LP increased the size of its syndicated revolving credit and term loan agreement to US$950 million. Draws of US$126 million under this agreement were used to partially finance PipeLines LP's Great Lakes acquisition.
- 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. TransCanada acquired 50 per cent of the units for US$300 million and invested an additional approximately US$12 million to maintain its general partner interest, increasing its total ownership to 32.1 per cent. The total private placement resulted in gross proceeds of approximately US$612 million which were used to partially finance PipeLines LP's Great Lakes acquisition.

Dividend

- On January 29, 2007, the Board of Directors of TransCanada increased the quarterly dividend on the Company's outstanding common shares for the quarter ending March 31, 2007 by six per cent to $0.34 per share from $0.32 per share. This is the seventh consecutive annual increase in the common share dividend.
- In January 2007, TransCanada's Board of Directors authorized the issue of common shares from treasury at a two per cent discount under the Company's Dividend Reinvestment and Share Purchase Plan (DRP), beginning with the dividend payable April 30, 2007 to shareholders of record at March 30, 2007.

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

	2006	2005	2004
Pipelines Net Earnings			
Excluding gains	**547**	630	577
Gain on sale of Northern Border Partners, L.P. interest	**13**	–	–
Gain on sale of PipeLines LP units	**–**	49	–
Gain on sale of Millennium	**–**	–	7
	560	679	584
Energy Net Earnings			
Excluding gains	**452**	258	211
Gain on sale of Paiton Energy	**–**	115	–
Gains related to Power LP	**–**	193	187
	452	566	398
Corporate	**39**	(36)	(2)
Net Income			
Continuing Operations(1)	**1,051**	1,209	980
Discontinued Operations	**28**	–	52
	1,079	1,209	1,032
Net Income Per Share			
Continuing Operations(2)	**$2.15**	$2.49	$2.02
Discontinued Operations	**0.06**	–	0.11
Basic	**$2.21**	$2.49	$2.13

	2006	2005	2004
(1)**Net Income from Continuing Operations:**			
Excluding gains	**1,038**	852	786
Gains as noted above	**13**	357	194
	1,051	1,209	980
(2)**Net Income Per Share from Continuing Operations:**			
Excluding gains	**$2.12**	$1.75	$1.62
Gains as noted above	**0.03**	0.74	0.40
	$2.15	$2.49	$2.02

RESULTS OF OPERATIONS

Effective June 1, 2006, TransCanada revised the composition and names of its reportable business segments to Pipelines and Energy. The financial reporting of these segments was aligned to reflect the internal organizational structure of the Company. Pipelines principally comprises the Company's pipelines in Canada, the U.S. and Mexico. Energy includes the Company's power operations, natural gas storage business and liquefied natural gas (LNG) projects in Canada and the U.S. The segmented information has been retroactively reclassified to reflect the changes in reportable segments. These changes had no impact on consolidated net income.

Net income for the year ended December 31, 2006 was $1,079 million or $2.21 per share compared to $1,209 million or $2.49 per share for 2005 and $1,032 million or $2.13 per share for 2004. This includes net income from discontinued operations of $28 million or $0.06 per share in 2006, reflecting bankruptcy settlements with Mirant Corporation and certain of its subsidiaries (Mirant) related to TransCanada's Gas Marketing business divested in 2001. Income from discontinued operations of $52 million or $0.11 per share in 2004 reflects income recognized on initially deferred gains relating to Mirant.

Net earnings for the year ended December 31, 2006 were $1,051 million or $2.15 per share compared to $1,209 million or $2.49 per share in 2005 and $980 million or $2.02 per share in 2004. Net earnings for 2006 included after-tax gains of $13 million from the sale of TransCanada's general partner interest in Northern Border Partners, L.P. Net earnings for 2005 included after-tax gains of $193 million on the sale of the Company's interest in TransCanada Power, L.P. (Power LP), $115 million on the sale of the Company's interest in P.T. Paiton Energy Company (Paiton Energy) and $49 million on the sale of PipeLines LP units.

Excluding gains of $13 million in 2006 and $357 million in 2005, net earnings in 2006 were $1,038 million or $2.12 per share, an increase of $186 million or $0.37 per share compared to 2005. This increase was mainly due to higher net earnings in Energy and Corporate, partially offset by decreased net earnings in Pipelines.

Excluding the gains on sale of the Northern Border Partners, L.P. interest in 2006 and the PipeLines LP units in 2005, net earnings in the Pipelines business decreased $83 million in 2006 compared to 2005. The decrease was primarily due to lower net earnings from the Canadian Mainline and the Alberta System as a result of lower approved rates of return on common equity (ROE) and lower average investment bases in 2006 compared to 2005. In addition, the Company's Other Pipelines businesses and the Gas Transmission Northwest System and the North Baja system (collectively GTN) experienced lower earnings in 2006.

Excluding the gain on the sale of Paiton Energy and gains related to the Company's investment in Power LP in 2005, Energy's net earnings for 2006 increased $194 million compared to 2005 as a result of higher operating income from each of its existing businesses as well as a $23-million favourable impact on future income taxes arising from reductions in Canadian federal and provincial income tax rates in 2006. These increases were partially offset by a loss of operating income associated with the sale of Power LP in 2005.

The increase in Corporate's net earnings in 2006 of $75 million compared to 2005 was primarily due to $72 million of positive income tax adjustments in 2006.

Net earnings increased $229 million or $0.47 per share in 2005 compared to 2004. The increase was primarily due to the inclusion of gains of $357 million or $0.74 per share in 2005 compared to gains of $194 million or $0.40 per share in 2004. Excluding gains, Pipeline's net earnings increased due to the inclusion of a full year of earnings from GTN in 2005 and the positive impact on earnings of a National Energy Board (NEB) decision to increase the Canadian Mainline's common equity component in its deemed capital structure. This was partially offset by the Canadian Mainline's lower average investment base, lower earnings related to operating cost savings, a decrease in the approved ROE and lower net earnings from the Company's Other Pipelines' businesses in 2005. Energy's net earnings, excluding gains, increased in 2005, compared to 2004, primarily due to higher operating income from Bruce Power A L.P. (Bruce A) and Bruce Power L.P. (Bruce B) (collectively Bruce Power), and Eastern Power Operations. A lower contribution from Western Power Operations and higher general administrative, support costs and other also reduced Energy's net earnings in 2005 compared to 2004. Corporate's net expenses increased in 2005 compared to 2004, primarily due to increased net interest expense on higher average long-term debt and commercial paper balances in 2005.

SUBSEQUENT EVENTS

ANR Acquisition

On February 22, 2007, TransCanada closed the acquisition of ANR and an additional 3.55 per cent interest in Great Lakes from El Paso Corporation for approximately US$3.4 billion, subject to certain post-closing adjustments, including approximately US$488 million of assumed long-term debt. The acquisition of ANR added approximately 17,000 kilometres (km) of natural gas transmission pipeline with a peak-day capacity of 6.8 Bcf/d. ANR also owns and operates natural gas storage facilities with a total capacity of approximately 230 Bcf. The acquisition was financed with a combination of proceeds from the Company's recent equity offering, cash on hand and funds drawn on existing and newly established loan facilities, discussed below.

In January 2007, TransCanada filed a final short form shelf prospectus with securities regulators in Canada and the U.S. to allow for the offering of up to $3.0 billion of common shares, preferred shares and/or subscription receipts in Canada and the U.S. until February 2009. The nature, size and timing of any financings will be dependent on TransCanada's assessment of its requirements for funding and general market conditions.

On February 6, 2007, TransCanada entered into an agreement with a syndicate of underwriters under which the underwriters agreed to purchase 39,470,000 subscription receipts from TransCanada and sell them to the public at a price of $38.00 each. The offering closed on February 14, 2007, resulting in gross proceeds to TransCanada of approximately $1.5 billion which were used towards financing the acquisition of ANR. TransCanada also granted the underwriters of the subscription receipts offering an option to purchase an additional 5,920,500 common shares at $38.00 per common share at any time up to and including March 16, 2007. Upon closing of the ANR acquisition, the subscription receipts were exchanged on a one-to-one basis for common shares of TransCanada without any further action of, or payment from, the holder.

In February 2007, the Company executed an agreement with a syndicate of banks for a US$2.2 billion, one-year bridge loan facility. The facility is committed and unsecured. The Company utilized $1.5 billion and US$700 million from this facility to partially finance the ANR acquisition of which $1.5 billion and US$20 million were subsequently repaid from the proceeds of the $1.5 billion subscription receipts offering and cash on hand, respectively.

In February 2007, the Company, through a wholly owned subsidiary, executed an agreement with a syndicate of banks to establish a new US$1.0 billion credit facility, consisting of a US$700 million five-year term loan and a US$300 million five-year extendible revolving facility. This facility is committed and unsecured. 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 as well as additional investments in PipeLines LP, described below.

Great Lakes Acquisition

On February 22, 2007, PipeLines LP closed its acquisition of a 46.45 per cent interest in Great Lakes from El Paso Corporation for approximately US$962 million, which included approximately US$212 million of assumed long-term debt, subject to certain post-closing adjustments. At December 31, 2006, TransCanada had a 13.4 per cent interest in PipeLines LP.

In February 2007, PipeLines LP increased the size of its syndicated revolving credit and term loan agreement from US$410 million to US$950 million. Incremental draws of US$126 million received under this agreement were used to partially finance PipeLines LP's Great Lakes acquisition.

On February 22, 2007, PipeLines LP completed a private placement offering of 17,356,086 common units at a price of US$34.57 per unit, of which 50 per cent of the units were acquired by TransCanada for US$300 million. TransCanada also invested an additional approximately US$12 million to maintain its general partnership ownership interest in PipeLines LP. As a result of TransCanada's additional investments in PipeLines LP, its ownership in PipeLines LP increased to 32.1 per cent. The total private placement resulted in gross proceeds to PipeLines LP of US$612 million, which were used to partially finance its Great Lakes acquisition. As a result of TransCanada's increased ownership in PipeLines LP, TransCanada's effective ownership in Tuscarora Gas Transmission Company (Tuscarora), Northern Border Pipeline

Company (Northern Border) and Great Lakes increased to 32.5 per cent (including one per cent held directly) 16.1 per cent and 68.5 per cent (including 53.55 per cent held directly), respectively.

FORWARD-LOOKING INFORMATION

Certain information in this MD&A includes forward-looking statements. All forward-looking statements are based on TransCanada's beliefs and assumptions based on information available at the time such statements were made. Factors which could cause actual results or events to differ materially from current expectations include, among other things, the ability of TransCanada to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the availability and price of energy commodities, regulatory decisions, changes in environmental and other laws and regulations, competitive factors in the pipeline and energy industry sectors, construction and completion of capital projects, access to capital markets, interest and currency exchange rates, technological developments and the current economic condition in North America. By its nature, such forward-looking information is subject to various risks and uncertainties, which could cause TransCanada's actual results and experience to differ materially from the anticipated results or other expectations expressed. Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date of this MD&A or as otherwise stated. TransCanada undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

NON-GAAP MEASURES

The Company uses the measures "funds generated from operations" and "operating income" in this MD&A. These measures do not have any standardized meaning in GAAP and are therefore considered to be non-GAAP measures. These measures may not be comparable to similar measures presented by other entities. These measures have been used to provide readers with additional information on the Company's liquidity and its ability to generate funds to finance its operations.

Funds generated from operations is comprised of 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 this MD&A. Operating income is used in the Energy segment and is comprised of revenues plus income from equity investments less operating expenses as shown on the consolidated income statement. Refer to the Energy section in this MD&A for a reconciliation of operating income to net earnings.

TRANSCANADA OVERVIEW

TransCanada is a leading North American energy infrastructure company with a strong focus on natural gas transmission and power generation opportunities located in regions in which it has significant competitive advantages. Natural gas transmission and power are complementary businesses for TransCanada. They are driven by similar supply and demand fundamentals, they are both capital-intensive businesses, and they use similar technology and operating practices. They are also businesses with significant long-term growth prospects.

North American natural gas demand is expected to increase primarily due to a growing demand for electricity. Experts predict that demand for electricity will increase at an average annual rate of approximately two per cent over the next ten years, primarily due to a growing population and an increase in gross domestic product. A large part of that demand growth is expected to be met by higher utilization of existing natural gas-fired generating plants.

Nuclear facilities have played, and will continue to play, a significant role in supplying North American power. Coal-fired plants remain the largest source of electric power in North America and coal reserves are significant. However, the long lead times required to complete new coal and nuclear projects may impede the development and completion of new coal or nuclear generation over the next five to ten years. As a result, North America is expected to continue to rely on natural gas-fired generation to satisfy its growing electricity needs in the near term. This is expected to lead to a significant increase in natural gas consumption. Natural gas demand in North America, including Mexico, is expected to grow to approximately 89 billion cubic feet per day (Bcf/d) by 2016, an increase of 14 Bcf/d when compared to 2006. New natural gas-fired power generation is expected to account for approximately 9 Bcf/d of that growth.

While growing demand will provide a number of opportunities, the natural gas industry also faces a number of challenges. North America has entered a period when it will no longer be able to rely solely on traditional sources of natural gas supply to meet its growing needs. Natural gas supply is limited and this is likely to continue until major investments are made in the infrastructure required to bring new supply to market. Looking forward, production from North America's traditional basins is expected to essentially remain flat over the next decade. An increase in production in the U.S. Rockies is expected to offset declines in other basins, including the Gulf of Mexico. This outlook for traditional basins means that northern gas and offshore LNG will be required to fill the shortfall between supply and demand. TransCanada is well positioned in North America to serve growing power generation demand in the near term and to bring these new natural gas supplies to market in the medium to long term.

TRANSCANADA'S STRATEGY

TransCanada's strong position in North America is the direct result of successfully executing its corporate strategy which was first adopted in 2000. While the plan has evolved over time in response to actual and anticipated changes in the business environment, it fundamentally remains the same. Today, TransCanada's corporate strategy consists of the following six components:

- maximize the profitability and long-term value of existing pipelines;
- grow the North American pipeline business, internally and through acquisitions;
- maximize the profitability and long-term value of existing power and other energy assets;
- grow the North American energy business, internally and through acquisitions;
- drive for operational excellence in all aspects of the business; and
- maximize TransCanada's competitive strength and enduring value.

Pipelines

Strategy
The Company's strategy in Pipelines is focused on both growing its North American natural gas transmission network and maximizing the profitability and long-term value of its existing pipeline assets. In order to grow the Pipelines segment, TransCanada is focusing on expanding and extending its existing systems to connect new supply to growing markets, increasing its ownership in partially owned entities, acquiring or constructing pipelines that provide TransCanada with a significant regional presence, expanding into the oil transmission business and, in the long term, connecting new sources of supply in the form of northern gas and LNG.

Over the past 50 years, TransCanada has developed significant expertise in large-diameter, cold-weather natural gas pipeline design, construction, operation and maintenance. It has also developed significant expertise in the design, optimization and operation of large gas turbine compressor stations. Today, TransCanada operates one of the largest, most sophisticated, remote-controlled pipeline networks in the world with a solid reputation for safety and reliability.

In addition to growing the North American Pipelines business, the Company continues to place a priority on maximizing the profitability and long-term value of its wholly owned pipelines. Efforts in this area are focused on achieving a fair return on invested capital and streamlining and harmonizing processes and tariff provisions for and among TransCanada's regulated pipelines. Further, the Company works collaboratively with its customers to develop and implement new services. TransCanada also provides services to many of its partially owned pipeline systems.

Existing Pipelines
TransCanada's natural gas transmission assets link the Western Canada Sedimentary Basin (WCSB) with premium North American markets. With approximately 42,000 km of pipeline (at December 31, 2006), the Company's network of wholly owned pipeline assets is one of the largest in North America.

In 2006, the wholly owned Alberta System gathered 67 per cent of the natural gas produced in western Canada or 17 per cent of total North American production. TransCanada exports natural gas from the WCSB to Eastern Canada and the U.S. West, Midwest and Northeast through four wholly owned pipeline systems:

- Canadian Mainline;
- Gas Transmission Northwest System;
- Foothills; and
- BC System.

In addition, the Company transports natural gas in Alberta through the TransCanada Pipeline Ventures Limited Partnership (Ventures LP) System.

In December 2006, TransCanada began transporting natural gas in Mexico through its Tamazunchale pipeline.

TransCanada also exports gas from the WCSB to eastern Canada as well as the U.S. West, Midwest and Northeast through six partially owned pipeline systems:

- Great Lakes;
- Trans Québec & Maritimes System (TQM);
- Iroquois Gas Transmission System (Iroquois);
- Portland Natural Gas Transmission System (Portland);
- Northern Border; and
- Tuscarora.

Northern Development
In 2006, TransCanada continued to pursue the Mackenzie Delta and Alaska North Slope projects. When the Mackenzie Gas Pipeline (MGP) project and the Alaska Highway Pipeline project are constructed and connected to TransCanada's existing infrastructure, they would represent additional growth opportunities for TransCanada and enhance the long-term viability and value of the Company's existing Pipelines business, especially the wholly owned pipelines currently transporting WCSB natural gas.

Mexico
In addition to the Tamazunchale pipeline, TransCanada continues to explore other pipeline and energy infrastructure opportunities in Mexico.

ANR and Great Lakes
On February 22, 2007, TransCanada closed its acquisition of ANR and an additional 3.55 per cent interest in Great Lakes. In addition, PipeLines LP closed its acquisition of a 46.45 per cent interest in Great Lakes.

Regulatory
In 2006, TransCanada's principal regulatory activities included a negotiated settlement with respect to 2006 Canadian Mainline tolls; filing a rate case with the Federal Energy Regulatory Commission (FERC) for new Gas Transmission Northwest System rates; filing an application with the NEB to integrate the BC System into the Foothills Zone 8 facilities (received NEB approval in February 2007); filing an application with the NEB seeking approval to transfer approximately 860 km of the Canadian Mainline's existing natural gas pipeline to oil service; filing an application with the NEB to construct and operate approximately 370 km of new oil pipeline, terminal facilities and pump stations; and filing

applications that sought approval to transfer a portion of the Canadian Mainline's assets to Keystone and to reduce the Canadian Mainline's rate base by the net book value (NBV) of the transferred assets (received NEB approval in February 2007).

Energy

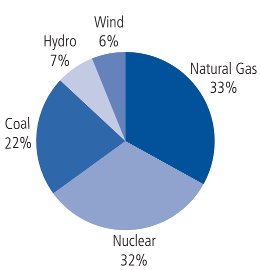
Strategy
TransCanada's strategy for growth and value creation in the Energy business has five key elements:

- focusing on markets where TransCanada has a competitive advantage;
- developing low-risk, greenfield generation projects, underpinned by long-term input and sales contracts with quality counterparties;
- acquiring low-cost, base-load power generation. The Company believes that being a low-cost provider and/or having long-term sales contracts is critical to being successful in volatile power markets;
- exploiting TransCanada's proven strong project management skills; and
- optimizing the profitability and reliability of the existing asset portfolio by operating the facilities as efficiently and cost-effectively as possible.

TransCanada's ability to successfully execute its strategy is related to a broad understanding of North American energy markets and a deep understanding of its core markets in Alberta, Ontario, Québec, and the northeastern U.S. In addition, the Company actively participates in deregulated and deregulating markets and has the ability to structure transactions and manage risk, which is critical to mitigating volatility in natural gas and power markets.

Existing Assets
TransCanada has built a substantial energy business over the past decade and has achieved a significant presence in power generation across Canada and the U.S. More recently, TransCanada has developed its natural gas storage business through investments in Alberta.

Power by Fuel Source



The power plants and power supply that TransCanada owns, operates and/or controls, including projects under construction, represent approximately 7,700 megawatts (MW) of power generation capacity in Canada and the U.S. TransCanada's portfolio of power supply is diversified: 33 per cent natural gas; 32 per cent nuclear; 22 per cent coal; seven per cent hydro and six per cent wind. TransCanada's power assets are primarily low-cost, base load generation and/or backed by secure, long-term power sales agreements. The Company's power assets are concentrated in two main regions: Western Power Operations in Alberta and Eastern Power Operations in the eastern Canada and New England markets.

Energy's natural gas storage assets are all located in Alberta. TransCanada owns or controls more than 130 billion cubic feet (Bcf) or approximately one third of the natural gas storage capacity in the province. TransCanada believes the market fundamentals for natural gas storage will remain strong into the future.

In 2006, TransCanada continued to add to its diverse portfolio of existing quality energy assets as follows:

Bécancour
Construction of the Bécancour cogeneration plant was completed and placed commercially in service in September 2006. The project was completed on time and under budget and is the largest greenfield power plant built by TransCanada to date.

Portlands Energy
In September 2006, Portlands Energy Centre L.P. (Portlands Energy) announced that it had signed a 20-year Accelerated Clean Energy Supply (ACES) contract with the Ontario Power Authority (OPA) to construct a natural gas generation plant to be located in downtown Toronto, Ontario.

Cartier Wind
In November 2006, the Baie-des-Sables wind farm went into commercial operation and is currently one of the largest wind farms in Canada, providing 110 MW of power to the Hydro-Québec grid.

Halton Hills
In November 2006, TransCanada announced that it had been awarded a contract to build, own and operate a natural gas-fired power plant near the town of Halton Hills, Ontario.

Bruce Power
Throughout 2006, work continued on the Bruce A capital project, consisting of the restart and refurbishment of the currently idle Units 1 and 2, extension of the operating life of Unit 3 by replacing its steam generators and fuel channels when required, and replacement of the steam generators on Unit 4.

Edson Gas Storage
Construction of the Edson natural gas storage facility was substantially completed and placed into service on December 31, 2006.

Broadwater and Cacouna LNG Facilities
TransCanada continues to pursue these two LNG proposals.

Operational Excellence

TransCanada maintains a high level of pipeline operating performance, as measured by the minimal disruptions for the Canadian Mainline, the Alberta System and GTN.

In 2006, TransCanada developed a technology program involving techniques to reduce the cost and environmental impact of constructing new pipeline. The program, which negates the need for large volumes of water, was applied to a segment of TransCanada's pipeline construction. The technology was accepted by the NEB which is expected to encourage further development by TransCanada and to promote wide-scale use.

Through its annual Customer Satisfaction Survey, TransCanada received feedback from customers served by its Canadian pipelines. The survey, conducted by Ipsos Reid in the fall of 2006, found that TransCanada maintained high levels of overall customer satisfaction. TransCanada's call centre, transactional systems and staff obtained the highest satisfaction levels. This reflects TransCanada's commitment to operational excellence in the provision of reliable and high-quality service to customers.

The Company was very productive in 2006 with respect to collaborative efforts with customers. The Mainline Tolls Task Force, the Alberta System Tolls, Tariff, Facilities and Procedures Committee, and the BC System and Foothills Shippers group produced a number of resolutions in 2006. These resolutions included new services, service enhancements, process improvements, a Canadian Mainline tolls settlement and the proposed integration of the BC System into the Foothills system, which was approved by the NEB in February 2007. Productive collaborative processes can result in significant costs savings for both TransCanada and the industry by avoiding costs associated with regulatory proceedings.

In Energy, TransCanada continued its commitment in 2006 to provide safe, low-cost operations and maintenance of all assets to ensure the highest possible reliability and availability. For power plants directly operated by TransCanada, the weighted average plant availability in 2006 was 93 per cent compared to 87 per cent in 2005.

In 2007, TransCanada will continue to focus efforts on efficiencies, operational reliability, the environment and safety. Greenhouse gas emissions management programs will continue to receive attention and further efforts will be undertaken to improve contractor safety.

Competitive Strength and Enduring Value

TransCanada's strategy includes:

- developing excellence in value-creating strategy, analysis and investment execution;
- appropriate financial capacity and flexibility, allowing TransCanada to build large scale infrastructure projects and act quickly on quality opportunities when they arise;
- using project development and project management skills, combined with strong facility construction and operational abilities;
- maintaining high standards in corporate governance practices;
- developing and sustaining its relationships and reputation with key stakeholders; and
- creating sustainable organizational strengths.

At December 31, 2006, TransCanada had approximately 2,350 employees who have expertise in gas transmission and power operations, project management, depth of market and industry knowledge, and financial acumen.

OUTLOOK

Since 2000, TransCanada has followed a long-term approach of growing its Pipelines and Energy businesses in a diligent and disciplined manner. In 2007 and beyond, the Company's net earnings and cash flow, combined with a strong balance sheet, are expected to continue to provide the financial flexibility for TransCanada to pursue opportunities and create additional long-term value for its shareholders.

In 2007, the Company will continue to implement its Pipelines strategy, including:

- integrating ANR into TransCanada's existing Pipelines business;
- becoming the operator of Great Lakes in conjunction with the acquisition of an additional 3.55 per cent interest in Great Lakes, bringing its direct total ownership to 53.55 per cent, with PipeLines LP owning the remaining interest;
- engaging in discussions with Alberta System stakeholders following the conclusion of the current three-year settlement that expires at the end of 2007;
- proceeding with the Gas Transmission Northwest System rate case, which is scheduled to be in negotiations and answering discovery until the hearing phase begins on October 31, 2007;
- advancing development of the Keystone Pipeline;
- working with the MGP owners and the Aboriginal Pipeline Group (APG), including participating in regulatory proceedings as may be required, to advance the MGP project;
- working with project stakeholders and the State of Alaska to further advance the proposed Alaska Highway Pipeline project;
- developing transportation solutions for new market and supply growth opportunities that lead to potential expansions of the Alberta System;
- becoming the operator of Northern Border; and
- working with joint venture partners of partially owned pipeline systems to develop additional supply and market options for system customers.

TransCanada will continue to grow its Energy business in 2007. As in prior years, this growth is expected to come from a mix of greenfield developments, new acquisitions and organic growth within its existing assets and markets. In particular, in 2007, TransCanada expects to:

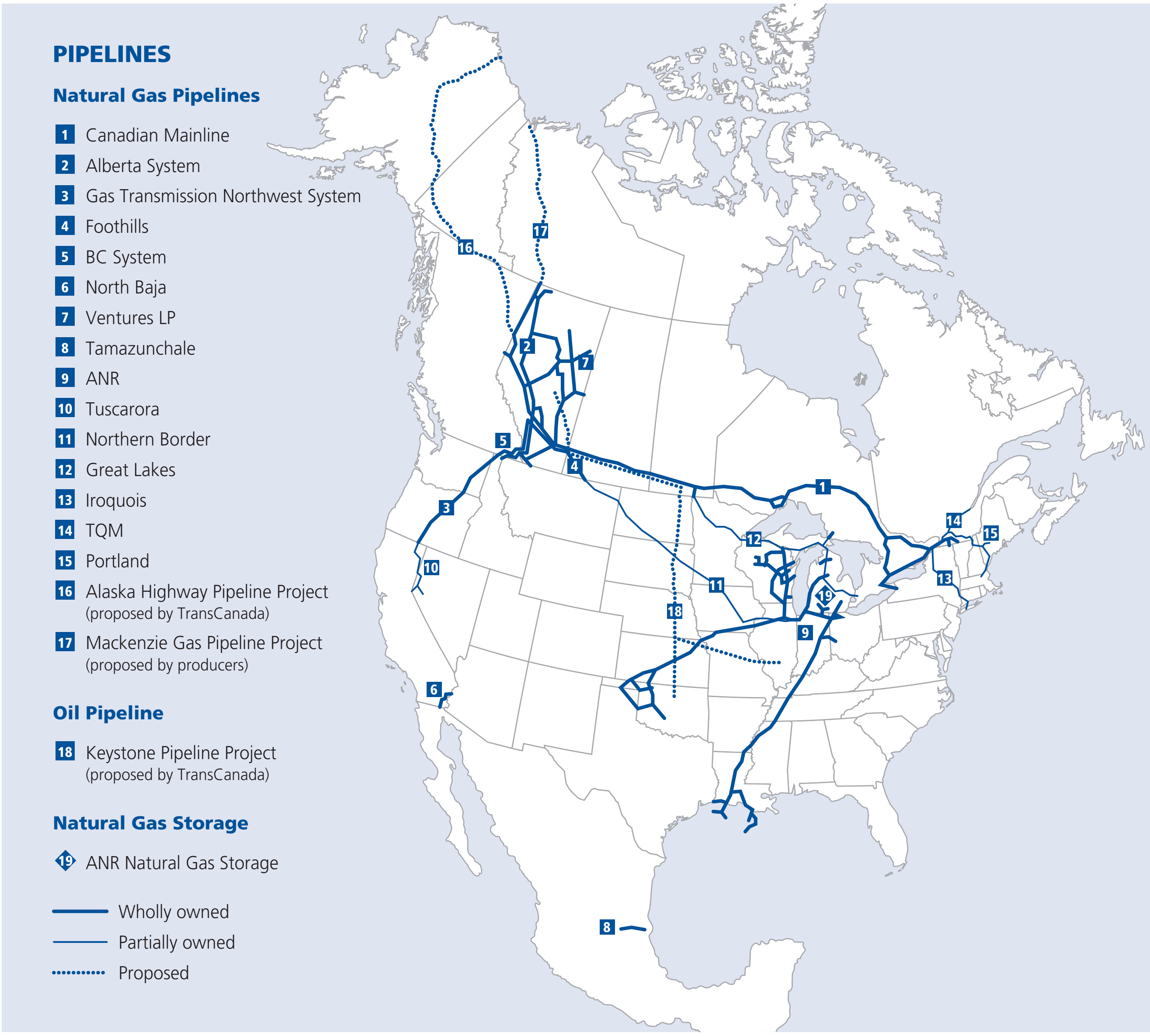
- work with Bruce A and its partners on the restart and refurbishment of the Bruce A units;
- complete construction of the second of six Cartier Wind projects in third quarter 2007 and begin construction of the third Cartier Wind facility;
- continue construction of the Portlands Energy project;
- initiate construction of the Halton Hills project;
- advance development of the Cacouna Energy project (Cacouna) and Broadwater Energy project (Broadwater) LNG facilities; and
- pursue additional greenfield projects and acquisition opportunities in TransCanada's key markets.

Although the following discussion reflects management's expectations for 2007, as discussed throughout this MD&A, a number of risk factors and developments may positively or negatively affect the actual results for 2007, as discussed throughout this MD&A, including the section entitled "Forward-Looking Information".

With the closing of the acquisition of ANR and Great Lakes, and the Company's increased ownership in PipeLines LP, TransCanada expects higher net earnings from Pipelines in 2007 compared to 2006. The combined effect of an expected decline in the average investment base of each of the Canadian Mainline and the Alberta System, and a decline in each of their formula-based regulated ROEs, is expected to decrease net earnings on these systems compared to 2006. Excluding any potential positive impact from a decision or settlement on the current rate case filing for the Gas Transmission Northwest System, reduced firm contract volumes on this system are expected to have a slightly negative impact on the results compared to 2006. In addition, Pipelines' 2006 net earnings included a $13 million gain on the sale of Northern Border Partners, L.P. interest, which will not occur in 2007. In 2007, TransCanada is expecting a positive impact from a full year of earnings from the Tamazunchale pipeline.

In Energy, net earnings in 2007 are expected to approximate or be slightly lower than 2006 net earnings due to the non-recurring $23-million future tax benefit in 2006 arising from reductions in federal and provincial income tax rates. Operating income is expected to be relatively consistent with 2006, although this is very dependent on commodity prices in each region as well as other factors such as hydrology and storage spreads. TransCanada's operating income from its investment in Bruce B can be significantly impacted by the effect, on uncontracted output, of changes in spot market prices for power. Excluding any changes in spot market prices for 2007 compared to 2006, Bruce Power's operating income is expected to decline in 2007 compared to 2006, reflecting lower projected generation volumes and higher operating costs resulting from an increase in planned outages in 2007. Western Power Operations' operating income in 2007 is expected to approximate 2006. Although TransCanada has sold forward significant output from its Alberta power purchase agreements (PPA) and power plants, Western Power Operations' operating income in 2007 can be significantly impacted by changes in the spot market price of power and market heat rates in Alberta. Eastern Power Operations' operating income is expected to increase in 2007 primarily due to a full year of operations for both the Bécancour natural gas-fired cogeneration facility and the first of six wind farms of the Cartier Wind project as well as the positive impact of the New England Power Pool (NEPOOL) forward capacity payments received by Ocean State Power (OSP) and TC Hydro commencing December 1, 2006. Gas Storage's operating income is expected to increase in 2007 over 2006 primarily due to the placing into service of the Edson facility at the end of 2006, partially offset by expected lower storage spreads.

Corporate's net expenses are expected to be higher in 2007 compared to 2006 primarily due to the income tax refunds and positive income tax adjustments realized in 2006 that are not expected to recur in 2007. Financing costs associated with the purchase of ANR are expected to increase net expenses in Corporate in 2007.



CANADIAN MAINLINE TransCanada's 100 per cent owned, 14,957 km natural gas transmission system in Canada 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 TransCanada's 100 per cent owned natural gas transmission system in Alberta gathers natural gas for use within the province and delivers it to provincial boundary points for connection with the Canadian Mainline, BC System, Foothills and other pipelines. The 23,498 km system is one of the largest carriers of natural gas in North America.

GAS TRANSMISSION NORTHWEST SYSTEM TransCanada's 100 per cent owned natural gas transmission system extends 2,174 km and links the BC System and Foothills with Pacific Gas and Electric Company's California Gas Transmission System, with Williams' Northwest Pipeline in Washington and Oregon, and with Tuscarora.

FOOTHILLS TransCanada's 100 per cent owned, 1,040 km natural gas 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.

BC SYSTEM TransCanada's 100 per cent owned natural gas transmission system extends 201 km from Alberta's western border through British Columbia (B.C.) to connect with the Gas Transmission Northwest System at the U.S. border, serving markets in B.C. as well as the Pacific Northwest, California and Nevada.

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

VENTURES LP Ventures LP, which is 100 per cent owned by TransCanada, owns a 121 km pipeline and related facilities which supply natural gas to the oil sands region of northern Alberta, and a 27 km pipeline which supplies natural gas to a petrochemical complex at Joffre, Alberta.

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

ANR On February 22, 2007, TransCanada acquired 100 per cent of the ANR natural gas transmission system which extends approximately 17,000 km from producing fields in Louisiana, Oklahoma, Texas and the Gulf of Mexico to markets in Wisconsin, Michigan, Illinois, Ohio and Indiana. This pipeline also connects with other pipelines to give access to supply from western Canada, the Rocky Mountain region and a variety of markets in the midwestern and northeastern U.S. ANR also owns and operates underground natural gas storage facilities in Michigan with a total capacity of approximately 230 Bcf.

TUSCARORA Tuscarora is owned or controlled 99 per cent by PipeLines LP and is a 491 km pipeline system transporting natural gas from the Gas Transmission Northwest System at Malin, Oregon to Wadsworth, Nevada with delivery points in northeastern California and northwestern Nevada. TransCanada operates Tuscarora and, at February 22, 2007, effectively owns or controls an aggregate 32.8 per cent interest in Tuscarora, of which 31.8 per cent is held indirectly through TransCanada's 32.1 per cent ownership interest in PipeLines LP and the remaining one percent is owned directly.

NORTHERN BORDER Northern Border is 50 per cent owned by PipeLines LP and is a 2,250 km natural gas pipeline system which serves the U.S. Midwest from a connection with Foothills near Monchy, Saskatchewan. In April 2007, TransCanada expects to become the operator of Northern Border. At February 22, 2007, the Company effectively owns approximately 16.1 per cent of Northern Border through its 32.1 per cent ownership interest in PipeLines LP.

GREAT LAKES Great Lakes is a 3,404 km pipeline system that connects with the Canadian Mainline at Emerson, Manitoba and serves markets in central Canada and the midwestern U.S. Effective February 22, 2007, TransCanada owns 53.55 per cent of Great Lakes and PipeLines LP owns the remaining 46.45 per cent. TransCanada's effective ownership of Great Lakes is 68.5 per cent of which 14.9 per cent is held indirectly through its 32.1 per cent ownership in PipeLines LP. TransCanada is the operator of Great Lakes.

IROQUOIS Iroquois connects with the Canadian Mainline near Waddington, New York and delivers natural gas to customers in the northeastern U.S. TransCanada has a 44.5 per cent ownership interest in this 666 km pipeline system.

TQM TQM is a 572 km natural gas pipeline system which connects with the Canadian Mainline and transports natural gas from Montréal to Québec City and to the Portland system. TransCanada holds a 50 per cent ownership interest in TQM and is the operator.

PORTLAND Portland is a 474 km pipeline that connects with TQM near East Hereford, Québec and delivers natural gas to customers in the northeastern U.S. TransCanada has a 61.7 per cent ownership interest in Portland and operates this pipeline.

TRANSGAS TransGas is a 344 km natural gas pipeline system which runs from Mariquita in the central region of Colombia to Cali in the southwest of Colombia. TransCanada holds a 46.5 per cent ownership interest in this pipeline.

GAS PACIFICO Gas Pacifico is a 540 km natural gas pipeline extending from Loma de la Lata, Argentina to Concepción, Chile. TransCanada holds a 30 per cent ownership interest in Gas Pacifico.

INNERGY INNERGY is an industrial natural gas marketing company based in Concepción, Chile that markets natural gas transported on Gas Pacifico. TransCanada holds a 30 per cent ownership interest in INNERGY.

HIGHLIGHTS

Net Earnings

- Net earnings from Pipelines decreased $119 million to $560 million in 2006 compared to $679 million in 2005, primarily due to a $49-million gain on the sale of PipeLines LP units in 2005 ($13-million gain on the sale of the interest in Northern Border Partners, L.P., in 2006), lower net earnings from the Canadian Mainline and the Alberta System as a result of a lower ROE and lower average investment bases in 2006, compared to 2005, and a $13-million Mainline adjustment in 2005 related to a 2004 regulatory decision.

ANR and Great Lakes Acquisition

- On February 22, 2007, TransCanada acquired ANR and an additional 3.55 per cent interest in Great Lakes.

Canadian Mainline

- The NEB approved a negotiated settlement of 2006 Mainline tolls which included a deemed common equity ratio of 36 per cent and incentives for managing costs through fixing certain components of the revenue requirement.

Alberta System

- The Alberta System continues to operate under the terms of the 2005-2007 Revenue Requirement Settlement approved by the Alberta Energy and Utilities Board (EUB) in 2005. The settlement includes a deemed common equity ratio of 35 per cent.

Gas Transmission Northwest System

- In June 2006, Gas Transmission Northwest System filed a rate case with the FERC. The comprehensive filing requests a number of tariff changes, including increased rates for transportation services.

Keystone

- TransCanada filed two applications with the NEB in 2006. In the first application, TransCanada applied to transfer a portion of its Canadian Mainline assets to Keystone and to reduce the Canadian Mainline's rate base by the NBV of the transferred assets. Approval was received from the NEB on this application in February 2007. In the second application, TransCanada applied to construct and operate new oil pipeline facilities.

Foothills and BC System

- In February 2007, TransCanada received approval from the NEB to integrate the BC System into Foothills in southern B.C.

North Baja

- In February 2006, TransCanada filed an application with the FERC to expand North Baja to accommodate bi-directional natural gas flow and to construct new pipeline and metering facilities. In October 2006, the FERC issued a preliminary approval of the application except for environmental issues which will be the subject of a future order.

PipeLines LP

- In April 2006, PipeLines LP acquired an additional 20 per cent partnership interest in Northern Border.
- In December 2006, PipeLines LP acquired an additional 49 per cent controlling general partner interest in Tuscarora, with the option to purchase Sierra Pacific Resources' remaining one per cent interest in Tuscarora in approximately one year.
- On February 22, 2007, PipeLines LP acquired a 46.45 per cent interest in Great Lakes.
- TransCanada became the operator of Tuscarora in December 2006 and Great Lakes in February 2007, and expects to begin operating Northern Border in April 2007.
- In February 2007, PipeLines LP completed a private placement offering of 17,356,086 units at a price of US$34.57 per unit. TransCanada acquired 50 per cent of the units for US$300 million, increasing its total ownership to 32.1 per cent. TransCanada also invested an additional approximately US$12 million to maintain its general partnership interest in PipeLines LP. The total private placement resulted in gross proceeds of approximately US$612 million which were used to partially finance the acquisition of the 46.45 per cent interest in Great Lakes.

Other Pipelines

- TransCanada sold its 17.5 per cent general partner interest in Northern Border Partners, L.P. for an after-tax gain of approximately $13 million.
- TransCanada continued its efforts to progress the proposed Alaska Highway Pipeline.
- TransCanada continued to fund the APG participation in the MGP project.
- In December 2006, TransCanada commenced commercial operations of the Tamazunchale pipeline in east-central Mexico.

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

	2006	2005	2004
Wholly Owned Pipelines			
Canadian Mainline	**239**	283	272
Alberta System	**136**	150	150
GTN[1]	**64**	71	14
Foothills	**21**	21	22
BC System	**6**	6	7
	466	531	465
Other Pipelines			
Great Lakes	**44**	46	55
Iroquois	**15**	17	17
PipeLines LP[2]	**4**	9	16
Portland	**13**	11	10
Ventures LP	**12**	12	15
TQM	**7**	7	8
Tamazunchale[3]	**2**	–	–
TransGas	**11**	11	11
Gas Pacifico/INNERGY[4]	**8**	6	4
Northern Development	**(5)**	(4)	(6)
General, administrative, support costs and other	**(30)**	(16)	(18)
	81	99	112
Gain on sale of Northern Border Partners, L.P. interest	**13**	–	–
Gain on sale of PipeLines LP units	**–**	49	–
Gain on sale of Millennium	**–**	–	7
	94	148	119
Net earnings	**560**	679	584

(1) TransCanada acquired GTN in November 2004. Amounts in this table reflect TransCanada's 100 per cent ownership interest in GTN's net earnings from the acquisition date.

(2) During 2005, TransCanada decreased its ownership interest in PipeLines LP to 13.4 per cent from 33.4 per cent.

(3) The Tamazunchale pipeline went into service December 1, 2006.

(4) Gasoducto del Pacifico S.A./INNERGY Holdings S.A.

In 2006, net earnings from the Pipelines business were $560 million compared to $679 million and $584 million in 2005 and 2004, respectively. Excluding the $49-million after-tax gain on the sale of PipeLines LP units in 2005 and the $13-million after-tax gain on the sale of TransCanada's general partner interest in Northern Border Partners, L.P. in 2006, Pipelines' net earnings for the year ended December 31, 2006 decreased $83 million compared to the same period in 2005. This decrease was primarily due to lower net earnings from the Canadian Mainline, the Alberta System, GTN and Other Pipelines.

The overall increase of $95 million in 2005 Pipelines net earnings compared to 2004 was mainly due to a full year of GTN net earnings, the $49-million gain related to PipeLines LP and higher Canadian Mainline net earnings in 2005 as a result of an April 2005 NEB decision that resulted in a positive $13-million adjustment related to 2004, partially offset by lower net earnings from Other Pipelines. Lower 2005 net earnings from Other Pipelines were primarily due to decreased earnings from Great Lakes, PipeLines LP and Ventures LP.

PIPELINES – FINANCIAL ANALYSIS

Canadian Mainline

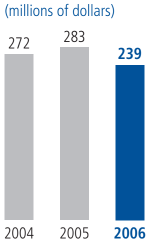
The Canadian Mainline is regulated by the NEB. The NEB sets tolls which provide TransCanada with the opportunity to recover its projected costs of transporting natural gas, including a return on the Canadian Mainline's average investment base. In addition, new facilities are approved by the NEB before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

In April 2006, the NEB approved TransCanada's application for a negotiated settlement of the 2006 Canadian Mainline tolls as filed. The settlement resulted in a revenue requirement of approximately $1.8 billion for 2006. The settlement also established the Canadian Mainline's fixed OM&A costs for 2006 at $174 million with variances between actual OM&A costs in 2006 and those agreed to in the settlement accruing to TransCanada. The majority of the other cost elements of the 2006 revenue requirement were to be treated on a flow-through basis. The settlement also provided TransCanada with an opportunity to realize modest additional net earnings through performance-based incentive arrangements. These incentive arrangements were focused on certain cost management activities and the management of fuel, and provided mutual benefits to both TransCanada and its customers. Further, the settlement included an ROE of 8.88 per cent as determined for 2006 under the NEB's return adjustment formula, on a deemed common equity ratio of 36 per cent.

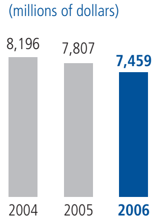
Net earnings of $239 million in 2006 were $44 million lower than 2005 net earnings of $283 million. The decrease was primarily due to a combination of a lower ROE and a lower average investment base in 2006 compared to 2005. In addition, 2005 net earnings included a positive adjustment of $13 million related to 2004 as a result of the NEB's decision in April 2005 on the Canadian Mainline's 2004 Tolls and Tariff Application (Phase II) which included an increase in the deemed common equity ratio to 36 per cent from 33 per cent for 2005 that was also effective for 2004. The 2006 NEB-approved Canadian Mainline tolls settlement that TransCanada reached with its customers and other interested parties included an ROE of 8.88 per cent, which was determined for 2006 under the NEB's return adjustment formula on a deemed common equity ratio of 36 per cent. The NEB-approved ROE for 2005 was 9.46 per cent.

The Canadian Mainline generated net earnings of $283 million in 2005, an increase of $11 million over 2004 earnings. The increase in net earnings was primarily due to the NEB's decision on the 2004 Tolls and Tariff Application (Phase II). The Phase II decision resulted in a $35-million ($22 million related to 2005 and $13 million related to 2004) increase to the Canadian Mainline's 2005 net earnings compared to 2004. However, this earnings increase was partially offset by the combination of a lower average investment base, lower cost savings and a lower approved ROE in 2005. The NEB-approved ROE decreased to 9.46 per cent in 2005 from 9.56 per cent in 2004.

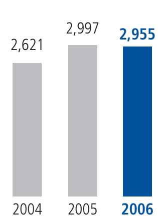
Canadian Mainline Net Earnings (millions of dollars)



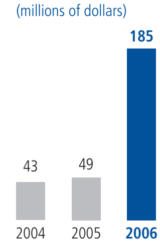
Canadian Mainline Average Investment Base (millions of dollars)



Canadian Mainline Throughput Volumes (Bcf)



Canadian Mainline Capital Expenditures (millions of dollars)



Alberta System

The Alberta System is regulated by the EUB primarily under the provisions of the *Gas Utilities Act (Alberta)* (GUA) and the *Pipeline Act (Alberta)*. Under the GUA, the Alberta System's rates, tolls and other charges, and terms and conditions of service are subject to approval by the EUB.

The Alberta System is currently operating under the 2005-2007 Revenue Requirement Settlement. The settlement was reached in 2005 with shippers and other interested parties regarding the annual revenue requirements of its Alberta System for the years 2005, 2006 and 2007. The settlement was approved by the EUB in June 2005 and encompassed all elements of the Alberta System revenue requirement, including operating, maintenance and administration (OM&A) costs, ROE, depreciation and income and municipal taxes.

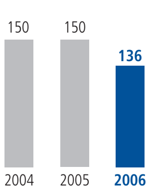
The Alberta System settlement fixed OM&A costs at $193 million for 2005, $201 million for 2006, and $207 million for 2007. In each year, any variance between actual OM&A and other fixed costs, and those agreed to in the settlement accrues to TransCanada. The majority of other cost elements of the 2005, 2006 and 2007 revenue requirements are treated on a flow-through basis.

The ROE will be calculated annually during the term of the settlement using the EUB formula for the purpose of establishing the annual generic rate of return for Alberta utilities on deemed common equity of 35 per cent. In addition, depreciation costs are determined using the depreciation rates and methodology that the Company proposed to the EUB in its 2004 General Rate Application (GRA).

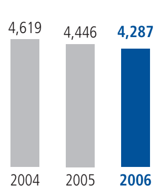
Net earnings of $136 million in 2006 were $14 million lower compared to 2005. The decrease was primarily due to a lower investment base and a lower approved rate of return in 2006. Net earnings in 2005 and 2006 reflect an ROE of 9.50 and 8.93 per cent, respectively, as prescribed by the EUB, on deemed common equity of 35 per cent.

Net earnings of $150 million in 2005 were unchanged from 2004 due to the negative impacts of a lower investment base and a lower approved rate of return in 2005 being offset by the positive impact of higher allowed operating costs in 2005 compared to 2004 as a result of cost disallowances in the EUB's decision on Phase 1 of the 2004 GRA. Net earnings in 2004 reflect an ROE of 9.60 as prescribed by the EUB, on deemed common equity of 35 per cent.

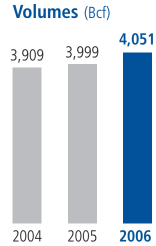
Alberta System Net Earnings (millions of dollars)



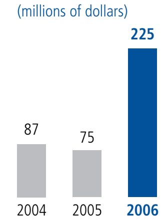
Alberta System Average Investment Base (millions of dollars)



Alberta System Throughput Volumes (Bcf)



Alberta System Capital Expenditures (millions of dollars)



GTN

GTN is regulated by the FERC, which has authority to regulate rates for natural gas transportation in interstate commerce. Both of GTN's systems, the Gas Transmission Northwest System and North Baja, operate under fixed rate models, under which maximum and minimum rates for various service types have been ordered by the FERC. GTN is permitted to discount or negotiate these rates on a non-discriminatory basis. In 2006, the Gas Transmission Northwest System operated under a rate case that was filed in 1994 and settled and approved by the FERC in 1996. In June 2006, the Gas Transmission Northwest System filed a new rate case with the FERC. North Baja's rates were established in the FERC's initial order in 2002 certifying construction and operation of the system. The net earnings of GTN are impacted by variations in contracted levels, volumes delivered and prices charged under the various service types that are provided, as well as by variations in the costs of providing services.

Net earnings for the year ended December 31, 2006 were $64 million, a $7-million decrease from the same period in 2005. This decrease was primarily due to lower transportation revenues, higher operating costs, the impact of a weaker

U.S. dollar and a provision for non-payment of contract transportation revenue from a subsidiary of Calpine Corporation that filed for bankruptcy protection. These negative factors were partially offset by an $18-million bankruptcy settlement ($29 million pre-tax) in first quarter 2006 with Mirant, a former shipper on the Gas Transmission Northwest System. Net earnings for November and December 2004 were $14 million.

Other Pipelines

TransCanada's direct and indirect investments in various natural gas pipelines are included in Other Pipelines. It also includes TransCanada's project development activities related to its pursuit of new pipelines and gas and oil transmission related opportunities throughout North America.

TransCanada's net earnings from Other Pipelines in 2006 were $94 million compared to $148 million and $119 million in 2005 and 2004, respectively. Excluding the gains on sale of Northern Border Partners, L.P. in 2006 and PipeLines LP units in 2005, net earnings for 2006 were $18 million lower compared to 2005. The decrease was primarily due to higher project development and support costs associated with growing the Pipelines business, reduced ownership in PipeLines LP, a weaker U.S. dollar and bankruptcy settlements received by Iroquois in 2005, partially offset by increased net earnings from Portland due to a bankruptcy settlement received in 2006.

Excluding the gains on sale of PipeLines LP units in 2005 and the Millennium Pipeline project (Millennium) in 2004, net earnings in 2005 were $13 million lower than 2004. The decrease was primarily due to lower net earnings from Great Lakes as a result of lower short-term revenues and higher operating and maintenance costs, and lower earnings from PipeLines LP as a result of the reduced ownership. Results were also negatively impacted by a weaker U.S. dollar in 2005.

PIPELINES – OPPORTUNITIES AND DEVELOPMENTS

ANR and Great Lakes Acquisition

On February 22, 2007, TransCanada closed its acquisition of ANR and an additional 3.55 per cent interest in Great Lakes from El Paso Corporation for approximately US$3.4 billion, subject to certain post-closing adjustments, including approximately US$488 million of assumed long-term debt. This transaction will significantly expand the Company's continental natural gas pipeline and storage operations.

ANR operates one of the largest interstate natural gas pipeline systems in the U.S., providing transportation, storage, and various capacity-related services to a variety of customers in both the U.S. and Canada. The system consists of approximately 17,000 km of pipeline with a peak-day capacity of 6.8 Bcf/d. It transports natural gas from producing fields in Louisiana, Oklahoma, Texas and the Gulf of Mexico to markets in Wisconsin, Michigan, Illinois, Ohio and Indiana. The pipeline system also connects with numerous other pipelines providing customers with access to diverse sources of supply from western Canada and the Rocky Mountain region and access to a variety of end-user markets in the midwestern and northeastern U.S.

ANR also owns and operates numerous underground natural gas storage facilities in Michigan with a total capacity of approximately 230 Bcf. Its facilities offer customers a high level of service flexibility allowing them to meet peak-day delivery requirements and to capture the value resulting from changing supply and demand dynamics. As part of the acquisition, TransCanada will also obtain certain natural gas supplies contained within production and storage reservoirs in Michigan.

Great Lakes

On February 22, 2007, PipeLines LP closed its acquisition of a 46.45 per cent interest in Great Lakes from El Paso Corporation for approximately US$962 million, subject to certain post-closing adjustments, including approximately US$212 million of assumed long-term debt. Great Lakes owns and operates a 3,402 km interstate natural gas pipeline system with a design capacity of 2.5 Bcf/d. TransCanada is the general partner of and holds a 32.1 per cent interest in PipeLines LP.

Canadian Mainline

In May 2006, TransCanada filed for approval of two Canadian Mainline services designed to meet the growing needs of natural gas-fired power generators in Ontario. These services are designed to ensure that shippers can access transportation on as little as 15 minutes notice so they can better match the timing of their natural gas transportation needs with the timing of their power generation requirements. The application was the subject of an oral public hearing in September 2006 and, in December 2006, the NEB approved implementation of the services with minor modifications.

In December 2006, TransCanada applied to the NEB for approval of a new receipt point at Gros Cacouna on the Canadian Mainline. The Company is also seeking affirmation of the tolling methodology that will apply to service from that point. The new receipt point would accommodate receipts of regassified LNG at Gros Cacouna, bringing a new source of supply to the Canadian Mainline to serve markets in eastern Canada and the U.S. Northeast. The NEB has established a procedure to deal with the Gros Cacouna, Québec receipt point application which includes an oral hearing expected to begin in April 2007.

Alberta System

On February 21, 2006, the EUB issued its decision on the 2005 GRA Phase II. The EUB approved the 2005 rate design as applied for. With this decision, TransCanada was able to finalize the 2005 and 2006 Alberta System tolls on March 14, 2006. The 2006 final tolls were effective April 1, 2006. TransCanada had been charging interim tolls since January 1, 2006 with the EUB's approval.

TransCanada filed for a Review and Variance on the Ventures LP's Transportation by Others (TBO) costs following the EUB decision on the 2004 GRA Phase I. At the time, the EUB denied certain costs associated with the Ventures LP's new TBO contract that was replacing the old TBO contract. In its decision on November 28, 2006, (Decision 2006-069), the EUB allowed for the recovery of approximately $1 million of costs due to the timing of the termination and commencement of the TBO contracts.

On November 30, 2006, the EUB finalized the 2007 generic ROE formula results. For 2007, the Alberta System's ROE will be 8.51 per cent; down from 8.93 per cent in 2006.

On December 20, 2006, the EUB approved TransCanada's application to charge interim tolls for transportation service, effective January 1, 2007. Final tolls for 2007 will be determined in first quarter 2007 upon updating of the flow-through cost components of the revenue requirement to reflect actual costs and revenues from the prior year.

GTN

In June 2006, TransCanada filed a rate case with the FERC for its Gas Transmission Northwest System. The rate case filing was primarily driven by decreased revenues due to contract non-renewals and shipper defaults. The comprehensive filing requested a number of tariff changes including an increase in rates for transportation services that became effective January 1, 2007, subject to refund. The proposed rates include an ROE of 14.5 per cent, a common equity ratio of 62.99 per cent and a depreciation rate for the transmission plant of 2.76 per cent. The rates in effect prior to the January 2007 rate increase were based on the last rate case filed in 1994.

In January 2007, TransCanada received a procedural order from the FERC establishing a timeline for the system's rate case proceeding. The hearing into this rate case is scheduled to commence on October 31, 2007.

BC System and Foothills

TransCanada filed applications with the NEB in early December 2005 for approval of 2006 tolls for Foothills and the BC System, reflecting an agreement with the Canadian Association of Petroleum Producers (CAPP) and other stakeholders to increase the deemed equity component of the capital structure of each system to 36 per cent from 30 per cent. On December 21, 2005, the NEB approved Foothills' application as filed. On February 22, 2006, the NEB finalized the BC System's 2006 tolls as filed.

In March 2006, TransCanada initiated discussions with shippers on the BC System to integrate the BC System with Foothills. The discussions culminated in a settlement agreement (Integration Settlement) between Foothills and CAPP.

The Integration Settlement amended an existing settlement for Foothills and includes a sharing mechanism for anticipated cost savings through increased administrative efficiencies arising out of the integration of the two systems. TransCanada filed Foothills and BC System's integration application and related approvals with the NEB on December 21, 2006. In February 2007, the NEB approved the application as filed.

Tamazunchale

In December 2006, TransCanada commenced commercial operations of the Tamazunchale pipeline. The 36 inch, 130 km pipeline in central Mexico extends from the facilities of Pemex Gas near Naranjos, Veracruz and transports natural gas under a 26-year contract with the Comisión Federal de Electricdad to an electricity generation station near Tamazunchale, San Luis Potosi.

The pipeline is designed to transport initial volumes of 170 million cubic feet per day (mmcf/d). Under the contract, the capacity of the Tamazunchale pipeline is expected to be expanded, beginning in 2009, to approximately 430 mmcf/d to meet the needs of two additional proposed power plants near Tamazunchale.

North Baja

On February 7, 2006, North Baja Pipelines LLC (North Baja) filed an application with the FERC to expand and modify its existing system to facilitate the importation of up to 2.7 Bcf/d of regassified LNG from Mexico into the California and Arizona markets. Specifically, North Baja proposes to modify its existing system to accommodate bi-directional natural gas flow, to construct a new meter station and a 36 inch pipeline to interconnect with Southern California Gas Company, to construct approximately 74 km of lateral facilities to serve electric generation facilities, and to loop its entire approximately 129 km existing system with a combination of 42 inch and 48 inch diameter pipeline. In addition to its FERC certificate of public convenience and necessity, which includes a determination on environmental issues, the project will need various permits and leases from the U.S. Bureau of Land Management, the California State Lands Commission and other agencies. On October 6, 2006, the FERC issued a preliminary determination approving all aspects of North Baja's proposal other than those related to environmental issues, which will be the subject of a future order.

Keystone Pipeline

In November 2005, TransCanada, ConocoPhillips Company and ConocoPhillips Pipe Line Company (CPPL) signed a Memorandum of Understanding which commits ConocoPhillips Company to ship crude oil on the proposed Keystone Pipeline, and gives CPPL the right to acquire up to a 50 per cent ownership interest in the pipeline. On January 31, 2006, TransCanada announced it has secured firm, long-term contracts totalling 340,000 barrels per day with durations averaging 18 years. The commitments were obtained through the successful completion of a binding Open Season held during fourth quarter 2005. With these commitments from shippers, TransCanada proceeded with regulatory filings for approval of the project.

At an estimated cost of approximately US$2.1 billion, the Keystone Pipeline is intended to transport approximately 435,000 barrels per day of crude oil from Hardisty, Alberta, to Patoka, Illinois through a 2,960 km pipeline system. The pipeline can be expanded to 590,000 barrels per day with additional pump stations. In addition to approximately 1,730 km of new pipeline construction in the U.S., the Canadian portion of the proposed project includes the construction of approximately 370 km of new pipeline and the conversion of approximately 860 km of TransCanada's existing pipeline facilities from natural gas to crude oil transmission. At December 31, 2006, the Company had capitalized $39 million related to Keystone.

In 2006, TransCanada and TransCanada's wholly owned subsidiary, TransCanada Keystone Pipeline GP Ltd. (Keystone), filed two regulatory applications with the NEB for the Canadian leg of the Keystone Pipeline. In June 2006, TransCanada filed the first application with the NEB seeking approval to transfer a portion of its Canadian Mainline natural gas transmission facilities to Keystone for use as part of the Keystone Pipeline. As part of the transfer application, TransCanada sought approval to reduce the Canadian Mainline's rate base by the NBV of the transferred facilities and to add the NBV of these facilities to the Keystone Pipeline rate base. Public hearings on the transfer application were completed in mid-November 2006. Approval was received from the NEB in February 2007.

In the second application, TransCanada sought approval to construct and operate new facilities in Canada including approximately 370 km of new oil pipeline, terminal facilities at Hardisty, Alberta and required pump stations. TransCanada is also seeking approval of the tolls and tariff for the pipeline. A decision on this application is anticipated from the NEB in fourth quarter 2007.

In April 2006, TransCanada filed an application with the U.S. Department of State for a Presidential Permit authorizing the construction, operation and maintenance of the U.S. portion of the Keystone Pipeline. In September 2006, the Department of State issued a formal notice of the application as well as a Notice of Intent to prepare an Environmental Impact Statement for the project.

In June 2006, TransCanada filed a petition with the Illinois Commerce Commission for a certificate authorizing the pipeline and granting authority to exercise eminent domain. The matter is expected to go to hearing in March 2007.

Shippers have also expressed interest in a proposed extension of the Keystone Pipeline to Cushing, Oklahoma. Through an Open Season, which will close at the end of first quarter 2007, binding commitments are being solicited to support the Cushing Extension, which would expand the Keystone Pipeline from a capacity of approximately 435,000 barrels per day to 590,000 barrels per day, and see the construction of a 468 km, 36 inch extension of the U.S. portion of the pipeline to Cushing. The expansion and extension would enable Keystone to provide access for increasing western Canadian crude supply to two key markets and transportation hubs at Patoka and Cushing. The expected capital cost is US$700 million and the targeted in-service date is fourth quarter 2010.

The Heartland extension is a proposed 190 km pipeline from Hardisty which would connect Keystone to the Fort Saskatchewan area. This extension would increase the Keystone Pipeline's market supply reach and provide incremental transportation service between Alberta's two major crude oil centres. The expected capital cost is approximately US$300 million. Discussions are under way with shippers to gauge the level of interest with an anticipation of moving forward with commercial arrangements later in 2007. The targeted in-service date of the Heartland extension is 2010/2011.

TransCanada is in the business of connecting energy supplies to markets and it views the Keystone opportunity as another way of providing a valuable service to its customers. Converting one of the Company's natural gas pipeline assets for oil transportation is an innovative, cost-competitive way to meet the need for pipeline expansions to accommodate anticipated growth in Canadian crude oil production during the next decade.

Mackenzie Gas Pipeline Project

The MGP is a 1,200 km natural gas pipeline proposed to be constructed from near Inuvik, Northwest Territories to the northern border of Alberta, where it would then connect to the Alberta System. In June 2006, TransCanada submitted an application to the EUB for approval of the Dickins-Vardie facilities, a $212-million capital project required to provide the Alberta System interconnection facilities for Mackenzie gas volumes.

Throughout 2006, the MGP proponents participated in public hearings convened by the NEB and by a Joint Review Panel (JRP) constituted to assess socio-economic and environmental aspects of the project. These latter hearings are expected to conclude in second quarter 2007, with the JRP's report ultimately being submitted into the NEB review process. Concurrently, the project proponents have been reassessing the capital cost estimate and construction schedule for the MGP, in light of overall industry cost escalations and labour shortages. A revised capital estimate for the project is expected to be filed with the NEB in first quarter 2007.

Apart from the Alberta System interconnection facilities, TransCanada's involvement with the MGP is derived from a 2003 agreement with the APG and the MGP by which TransCanada agreed to finance the APG's one-third share of the pipeline's pre-development costs associated with the project. These costs are currently forecasted to be approximately $145 million by the end of 2007. Cumulative advances made by TransCanada in this respect totalled $118 million at December 31, 2006 and are included in Other Assets. These amounts constitute a loan to the APG, which becomes repayable only after the date upon which the pipeline commences commercial operations. The total amount of the loan is expected to ultimately form part of the rate base of the pipeline, and the loan will subsequently be repaid from the APG's share of available future pipeline revenues or from alternate financing. If the project does not proceed, TransCanada has no recourse against the APG for recovery of advances made. Accordingly, the recovery of the advances is dependent upon a successful outcome of the project.

Under the terms of certain MGP agreements, TransCanada holds an option to acquire up to five per cent equity ownership in the pipeline at the time of the decision to construct. In addition, TransCanada gains certain rights of first refusal to acquire 50 per cent of any divestitures by existing partners and an entitlement to obtain a one-third interest in all expansion opportunities once the APG reaches a one-third ownership share, with the other pipeline owners and the APG sharing the balance.

Alaska Highway Pipeline Project

In 2006, TransCanada continued its discussions with Alaska North Slope producers and the State of Alaska regarding the Alaskan portion of the proposed Alaska Highway Pipeline Project. In early 2006, Alaska's State administration reached a preliminary agreement with ConocoPhillips Alaska Inc., BP Exploration (Alaska) Inc. and ExxonMobil Alaska Production Inc. for the pipeline project. However, the State Legislature did not ratify that agreement. Alaska's new Governor, elected in November 2006, has indicated the new administration intends to introduce a different process for the pipeline project in 2007.

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

Western Supply and Markets

The primary driver for infrastructure projects for the Alberta System is the development of natural gas supply and market demand in the various regions served by the Alberta System. In 2006, natural gas prices were lower than in 2005 which resulted in some slowdown in natural gas drilling activity levels. Nevertheless, activity remains strong which has resulted in supply growth in some regions of western Canada and an increased requirement for new transmission infrastructure. The primary source of supply growth has been deeper conventional drilling in western Alberta, northeastern B.C. and coalbed methane development in central Alberta.

TransCanada will continue to focus on the cost effective and timely connection of new gas production volumes so that customers can promptly access markets. As well, service flexibility will continue to be a focus to ensure TransCanada remains competitive.

TransCanada received approval from the EUB in April 2006 to construct new natural gas transmission facilities to serve the firm intra-Alberta delivery contract requirements of oil sand developers in the Fort McKay area. These facilities include 127 km of pipeline and three metering facilities at an estimated capital cost of $125 million. In addition to the proposed Fort McKay facilities, TransCanada constructed additional metering facilities to serve approximately 200 mmcf/d of firm intra-Alberta delivery contracts.

Eastern Supply and Markets

Historically, TransCanada's eastern pipeline system has been supplied by long-haul flows from western Canada and by volumes received from storage fields and interconnecting pipelines in southwestern Ontario. In the future, the eastern pipeline system may also be supplied by LNG deliveries from proposed regassification facilities in Québec and the northeastern U.S.

Power generation continues to be the primary driver for incremental gas demand in eastern Canada and the northeastern U.S. Power projects that require significant volumes of natural gas continue to be developed, supporting utilization of the eastern pipeline system. Aligned with these power project developments, TransCanada received NEB approval in 2006 for two new services targeted at attracting incremental demand for natural gas transportation on the Canadian Mainline system.

In addition, TransCanada completed construction of three NEB-approved facilities on its Canadian Mainline system in 2006. This included the Stittsville and Deux Rivières loops of approximately 38 km of 42 inch pipe with a capital cost of approximately $113 million, and the Les Cèdres loop of approximately 21 km of 36 inch pipe with a capital cost of $56 million.

PIPELINES – BUSINESS RISKS

Competition

TransCanada faces competition at both the supply end and the market end of its systems. The competition is a result of other pipelines accessing the increasingly mature WCSB as well as markets served by TransCanada's pipelines. In addition, the continued expiration of long-term firm transportation (FT) contracts has resulted in significant reductions in long-term firm contracted capacity on the Canadian Mainline, the Alberta System, the BC System and the Gas Transmission Northwest System, and shifts to short-term firm contracts.

TransCanada's primary source of natural gas supply is the WCSB. As of December 2005, the WCSB had remaining discovered natural gas reserves of approximately 57 trillion cubic feet and a reserves-to-production ratio of approximately nine years at current levels of production. Historically, additional reserves have continually been discovered to maintain the reserves-to-production ratio at close to nine years. Natural gas prices in the future are expected to be higher than long-term historical averages due to a tighter supply/demand balance, which should stimulate exploration and production in the WCSB. However, the WCSB's natural gas supply is expected to remain essentially flat. With the expansion of capacity on TransCanada's wholly and partially owned pipelines over the past decade and the competition provided by other pipelines combined with significant growth in natural gas demand in Alberta, TransCanada anticipates there will be excess pipeline capacity out of the WCSB for the foreseeable future.

TransCanada's Alberta System is the major natural gas gathering and transportation system for the WCSB, connecting most of the natural gas processing plants in Alberta to domestic and export markets. The Alberta System has faced, and will continue to face, increasing competition from other pipelines. An emerging competitive issue for the Alberta System is the existence and access to natural gas liquids (NGLs) contained in the gas that is transported by the pipeline. The current extraction convention in Alberta allocates a heat content value to the receipt point shippers at the overall Alberta System average gas composition. This averaging is becoming a significant issue for northern gas producers whose gas is generally rich in NGL content as they seek to extract the full value of the NGLs. Alberta's petrochemical industry is also very interested in the issue as it relies on NGLs as their feedstock. The EUB is aware of the current extraction convention inequities and has indicated that they will commission a process to address these concerns.

The Canadian Mainline is TransCanada's cross-continental natural gas pipeline serving midwestern and eastern markets in Canada and the U.S. The demand for natural gas in TransCanada's key eastern markets is expected to continue to increase, particularly to meet the expected growth in natural gas-fired power generation. Although there are opportunities to increase market share in Canadian and U.S. export markets, TransCanada faces significant competition in these regions. Consumers in the northeastern U.S. generally have access to an array of pipeline and supply options. Eastern Canadian markets that historically received Canadian supplies only from TransCanada are now capable of receiving supplies from new pipelines into the region that can source western and Atlantic Canadian, and U.S. supplies.

Over the last few years, the Canadian Mainline has experienced reductions in long-haul FT contracts. This has been partially offset by increases in short-haul contracts. While decreases in throughput do not directly impact the Canadian Mainline earnings, such decreases will impact the competitiveness of its tolls. Over the course of 2005 and into early

2006, strong prices in eastern Canada and the northeastern U.S. resulted in higher than anticipated flows on the Canadian Mainline. Moderating prices in these markets in the latter part of 2006 have reduced flows toward expected levels. Looking forward, in the short to medium term, there is limited opportunity to further reduce per unit tolls by increasing long-haul volumes on the Canadian Mainline.

The Gas Transmission Northwest System must compete with other pipelines to access natural gas supplies as well as to access markets. Transportation service capacity on the Gas Transmission Northwest System provides customers with access to supplies of natural gas primarily from the WCSB and serves markets in the Pacific Northwest, California and Nevada. These three markets may also access supplies from other competing basins in addition to supplies from the WCSB. Historically, natural gas supplies from the WCSB have been competitively priced in relation to natural gas supplies from the other supply regions serving these markets. The Gas Transmission Northwest System experienced significant contract non-renewals in 2005 and 2006 as natural gas transported from the WCSB on the Gas Transmission Northwest System competes for the California and Nevada markets against supplies from the Rocky Mountain and southwestern U.S. supply basins. In the Pacific Northwest market, natural gas transported on the Gas Transmission Northwest System competes against the Rocky Mountain natural gas supply as well as additional western Canadian supply transported by other pipelines.

In October 2006, the Gas Transmission Northwest System's largest customer, Pacific Gas & Electric Company (PG&E), extended its contract to October 31, 2008. In 2006, PG&E accounted for approximately 22 per cent of the Gas Transmission Northwest System's revenue. By October 31, 2007, PG&E will inform TransCanada whether it elects to either extend the contract beyond November 2008, utilize the contract's right of first refusal process or terminate the contract.

Transportation service on North Baja provides access to natural gas supplies primarily from both the Permian Basin, located in western Texas and southeastern New Mexico, and the San Juan Basin, primarily located in northwestern New Mexico and Colorado. North Baja delivers gas to the Gasoducto Bajanorte Pipeline at the California/Mexico border, which transports the gas to markets in northern Baja California, Mexico. While there are currently no direct competitors to deliver natural gas to North Baja's downstream markets, the pipeline may compete with fuel oil, which is an alternative to natural gas in the operation of some electric generation plants in the North Baja region.

Counterparty Risk

The risk of counterparty default is always present. In December 2005, Calpine Corporation and certain of its subsidiaries (Calpine) filed for bankruptcy protection in both Canada and the U.S. Calpine repudiated its transportation contracts on certain of TransCanada's Canadian pipelines effective January 1, 2007 as allowed under a Companies' Creditors Arrangement Act Order. Given that TransCanada considers itself prudent in having obtained the maximum financial assurances allowable under the respective Canadian tariffs, TransCanada will make an application to the regulator for recovery under the current regulatory model for any lost revenue, net of assurances and any revenues from the defaulted capacity. Should Calpine be successful in rejecting its contracts on certain of TransCanada's U.S. pipelines, the unmitigated annual after-tax exposure of the contract obligations is estimated at $10 million for the Gas Transmission Northwest System. Mitigating factors exist which may reduce this exposure including recontracting the capacity where possible and recovery from bankruptcy proceedings. The potential impact of such mitigating factors and the resulting net exposure are unknown at this time.

Regulatory Financial Risk

Regulatory decisions continue to have a significant impact on the financial returns for existing and future investments in TransCanada's Canadian wholly owned pipelines. TransCanada remains concerned that the approved financial returns fail to be competitive with returns from assets of similar risk and will discourage additional investment in existing Canadian natural gas transmission systems. In recent years, TransCanada applied for an ROE of 11 per cent on 40 per cent deemed common equity for both the Canadian Mainline and the Alberta System to the NEB and the EUB, respectively. The outcome of these proceedings resulted in the Canadian Mainline's current 36 per cent deemed equity thickness and the Alberta System's 35 per cent deemed equity thickness. Additionally, the NEB reaffirmed its ROE formula, while the EUB set a generic ROE which largely aligns with the NEB's formula. In 2006, the NEB's ROE formula declined to 8.88 per cent from the 2005 ROE of 9.46 per cent and the EUB's generic ROE declined to 8.93 per cent from 9.50 per cent in 2005. In 2007, the Canadian Mainline and the Alberta System's ROEs continued to decline, dropping to 8.46 percent and 8.51 per cent, respectively.

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

PIPELINES – OTHER

Safety
TransCanada worked closely with regulators, customers and communities during 2006 to ensure the continued safety of employees and the public. In 2006, TransCanada experienced two small diameter pipeline line-breaks located in remote areas of northern Alberta. The breaks released sweet natural gas and resulted in minimal impact with no injuries or property damage. Under the approved regulatory models in Canada, expenditures for pipeline integrity on the NEB and the EUB regulated pipelines are treated on a flow-through basis and, as a result, have no impact on TransCanada's earnings. The Company expects to spend approximately $100 million in 2007 for pipeline integrity on its wholly owned pipelines, which approximates the amount spent in 2006. TransCanada continues to use a rigorous risk management system that focuses spending on issues and areas that have the largest impact on maintaining or improving the reliability and safety of the pipeline system. TransCanada utilizes a comprehensive management system of policies, programs and procedures to ensure the occupational safety of employees and contractors.

Environment
In 2006, TransCanada continued to address environmental issues associated with its historical operations through proactive environmental monitoring, sampling and site remediation programs. Environmental site assessments were completed on the assets of the BC System, the Alberta System and the Canadian Mainline. The building containment integrity improvement program also continued at compressor station sites across the Canadian Mainline. Additionally, the demolition and clean up of four mainline compressor plants was carried out in 2006. TransCanada will continue to actively invest in improving its environmental protection practices in 2007 and the future.

For information on management of risks with respect to the Pipelines business, refer to the "Risks and Risk Management" section of this MD&A.

PIPELINES – OUTLOOK

As demand for natural gas continues to grow across North America, TransCanada's Pipelines business will continue to play a critical role in the reliable transportation of natural gas. For 2007, the business will continue to focus on the reliable delivery of natural gas to growing markets, connecting new supply, progressing development of new infrastructure to connect natural gas from the north, LNG in the east, and development of the Keystone Pipeline.

It is expected that producers will continue to explore and develop new fields, particularly in northeastern B.C. and the west central foothills regions of Alberta. There will also be significant activity aimed at unconventional resources such as coalbed methane although activity is expected to decline from last year's level. New facilities will be required to move this incremental supply from the location of the resource. New customer requests to serve markets in eastern Canada and the U.S. will require expansion of certain facilities on the Canadian Mainline for 2007 and 2008. This will include the addition of 18 MW of compression and a 7 km looping project. The estimated capital cost for these projects is $63 million.

It is expected that incremental supply from LNG will serve growing North American markets in the mid to long term. As a result, TransCanada will take prudent steps to further understand the potential commercial and operational implications of connecting LNG facilities to those systems affected.

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

Earnings

With the closing of the acquisition of ANR and Great Lakes, and the Company's increased ownership in PipeLines LP, TransCanada expects higher net earnings from Pipelines in 2007 compared to 2006. TransCanada's earnings from its Canadian Wholly Owned Pipelines are primarily determined by the average investment base, ROE, deemed common equity and opportunity for incentive earnings. In the short to medium term, the Company expects a modest level of investment in these mature assets and, therefore, anticipates a continued net decline in the average investment base due to depreciation. Accordingly, without an increase in ROE, deemed common equity or incentive opportunities, future earnings from the Canadian Wholly Owned Pipelines are anticipated to decrease. However, these mature assets will continue to generate strong cash flows that can be redeployed to other projects offering higher returns. Under the current regulatory model, earnings from the Canadian Wholly Owned Pipelines are not affected by short-term fluctuations in the commodity price of natural gas, changes in throughput volumes or changes in contract levels. In addition, the Tamazunchale pipeline will provide an increase in 2007 earnings as a result of its first full year of operations.

In November 2006, the NEB established the 2007 ROE for the Canadian Mainline at 8.46 per cent compared to 8.88 per cent in 2006. In addition, the 2007 average investment base is expected to continue to decline. These two factors are expected to lower earnings on the Canadian Mainline in 2007, relative to 2006, barring any offsetting factors.

Alberta System's earnings will be negatively influenced in 2007 by the decrease in the EUB's generic ROE to 8.51 per cent in 2007 from 8.93 per cent in 2006, and the anticipated decrease in the average investment base. The three-year revenue requirement settlement reached in 2005 does provide the opportunity for limited incentive earnings as the settlement contains some at-risk components. There is a possibility that the at-risk OM&A cost components of the settlement will have a negative impact on the Alberta System's earnings in 2007.

In 2007, reduced firm contract volumes on the Gas Transmission Northwest System, partially due to the bankruptcy of Calpine, are expected to have a negative impact on the Gas Transmission Northwest System's earnings compared to 2006. It is uncertain what impact the rate case proceeding may have on the system's financial results. Net earnings, excluding gains, from Other Pipelines are expected to be relatively consistent with 2006.

Capital Expenditures

Total capital spending for the Wholly Owned Pipelines during 2006 was $434 million. Overall capital spending for the Wholly Owned Pipelines in 2007 is expected to be approximately $400 million, excluding any capital expenditures for ANR.

NATURAL GAS THROUGHPUT VOLUMES
(Bcf)

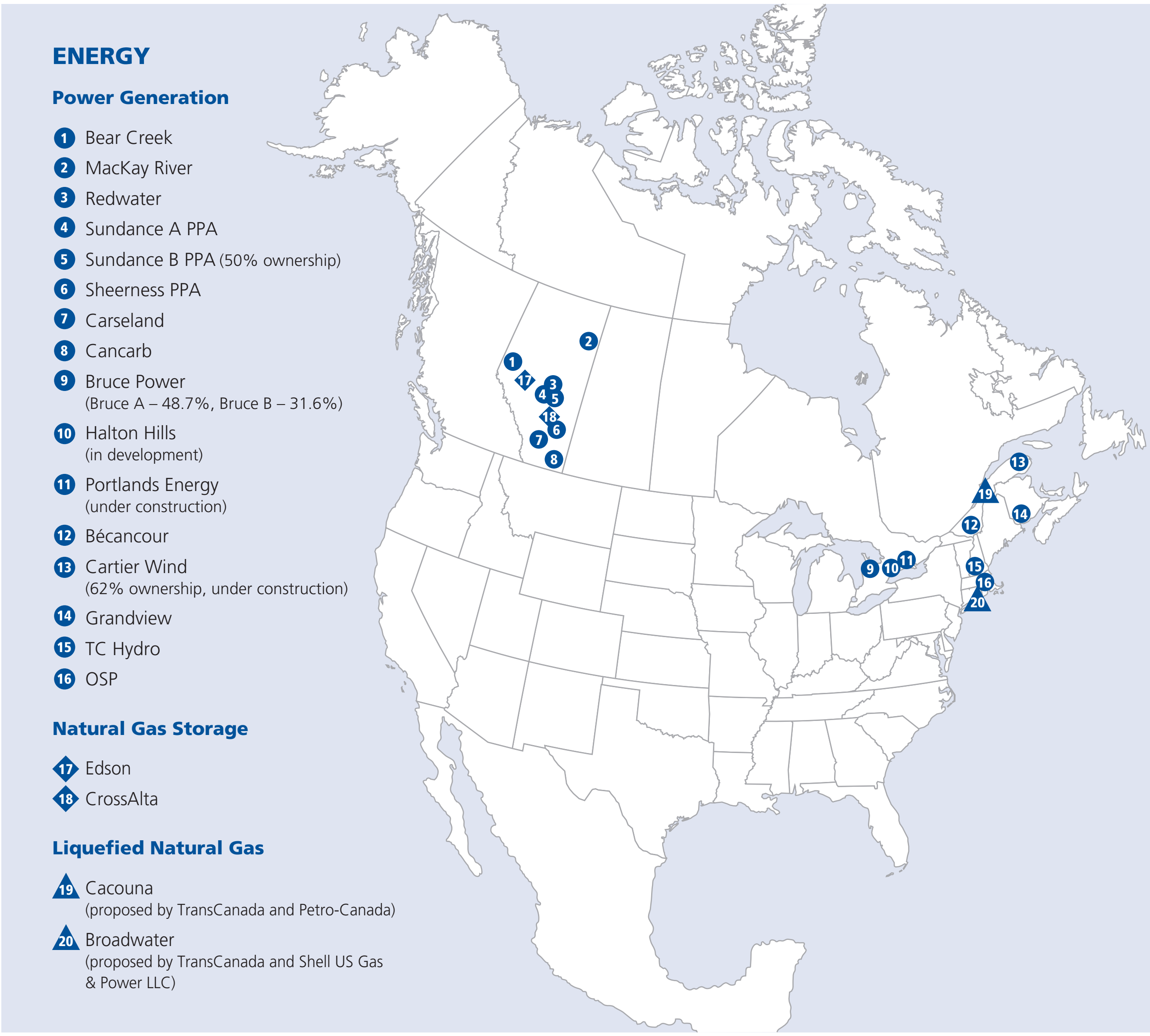
	2006	2005	2004
Canadian Mainline[1]	**2,955**	2,997	2,621
Alberta System[2]	**4,051**	3,999	3,909
Gas Transmission Northwest System[3]	**790**	777	181
Foothills	**1,051**	1,051	1,139
BC System	**351**	321	360
North Baja[3]	**95**	84	13
Great Lakes	**816**	850	801
Northern Border	**799**	808	845
Iroquois	**384**	394	356
TQM	**158**	166	159
Ventures LP	**179**	138	136
Portland	**52**	62	50
Tuscarora	**28**	25	25
Gas Pacifico	**52**	34	28
TransGas	**22**	19	18
Tamazunchale[4]	**–**	–	–

(1) Canadian Mainline deliveries originating at the Alberta border and in Saskatchewan in 2006 were 2,224 Bcf (2005 – 2,215 Bcf; 2004 – 2,017 Bcf).

(2) Field receipt volumes for the Alberta System in 2006 were 4,160 Bcf (2005 – 4,034 Bcf; 2004 – 3,952 Bcf).

(3) TransCanada acquired GTN on November 1, 2004. The delivery volumes for 2004 represent November and December 2004 throughput for GTN.

(4) The Tamazunchale pipeline went into service December 1, 2006.



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

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

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

SUNDANCE A&B The Sundance power facility in Alberta is the largest coal-fired electrical generating facility in Western Canada. TransCanada owns the 560 MW Sundance A PPA, which expires in 2017. TransCanada effectively owns 50 per cent of the 706 MW Sundance B PPA, which expires in 2020.

SHEERNESS The Sheerness plant consists of two 390 MW coal-fired thermal power generating units. TransCanada owns the 756 MW Sheerness PPA, which expires in 2020.

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

CANCARB The 27 MW Cancarb facility at Medicine Hat, Alberta is fuelled by waste heat from TransCanada's adjacent thermal carbon black facility.

BRUCE POWER TransCanada owns 31.6 per cent of Bruce B, consisting of operating Units 5 to 8 with approximately 3,200 MW of generating capacity. In addition, TransCanada owns 48.7 per cent of Bruce A, consisting of operating Units 3 and 4 with approximately 1,500 MW of generating capacity and currently idle Units 1 and 2 with approximately 1,500 MW of generating capacity, which are currently being refurbished and are expected to restart in late 2009 or early 2010.

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

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

BÉCANCOUR Construction of the 550 MW Bécancour natural gas-fired cogeneration power plant located near Trois-Rivières, Québec was completed and the plant placed into service in September 2006. The entire power output will be supplied to Hydro-Québec under a 20-year power purchase contract. Steam is also sold to industrial customers for use in commercial processes.

CARTIER WIND Construction of the 740 MW Cartier Wind project, 62 per cent owned by TransCanada, continued in 2006. The first of six wind projects, Baie-des-Sables, with a generation capacity of 110 MW, was placed into service in November 2006. Planning and construction on the remaining five projects will continue, subject to future appropriations and approvals.

GRANDVIEW A 90 MW natural gas-fired cogeneration power plant located in Saint John, New Brunswick was commissioned and placed into service in January 2005. Under a 20-year tolling arrangement, 100 per cent of the plant's heat and electricity output is sold to Irving Oil.

TC HYDRO TransCanada's hydroelectric facilities on the Connecticut and Deerfield Rivers consist of 13 stations and associated dams and reservoirs with a total generating capacity of 567 MW and are located in New Hampshire, Vermont and Massachusetts.

OSP The OSP plant is a 560 MW natural gas-fired, combined-cycle facility in Rhode Island.

EDSON Edson is an underground natural gas storage facility connected to the Alberta System located near Edson, Alberta. The 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. Construction of the Edson facility was substantially completed in third quarter 2006 and the facility was placed into service on December 31, 2006.

CROSSALTA CrossAlta is an underground natural gas storage facility connected to the Alberta System and is located near Crossfield, Alberta. CrossAlta has a working natural gas capacity of 50 Bcf with a maximum deliverability capability of 400 mmcf/d. TransCanada holds a 60 per cent ownership in CrossAlta.

CACOUNA Cacouna, a joint venture with Petro-Canada, is a proposed LNG project in Québec at Gros Cacouna harbour on the St. Lawrence River, capable of receiving, storing and regassifying imported LNG with an average send-out capacity of approximately 500 mmcf/d of natural gas.

BROADWATER Broadwater, a joint venture with Shell US Gas & Power LLC, is a proposed LNG project located offshore of New York State in Long Island Sound, capable of receiving, storing and regassifying imported LNG with an average send-out capacity of approximately 1 Bcf/d of natural gas.

HIGHLIGHTS

Net Earnings

- Energy's net earnings in 2006 were $452 million compared to $566 million in 2005.
- Excluding gains related to Power LP and Paiton Energy in 2005, Energy's net earnings in 2006 increased $194 million to $452 million compared to $258 million in 2005, primarily due to increased operating income from Western Power Operations.

Expanding Asset Base

- At December 31, 2006, approximately 2,100 MW of new power plants were under construction, with an anticipated total capital cost of more than $3.2 billion.
- Since 1999, TransCanada's Power business has grown its nominal generating capacity by approximately 5,200 MW (including 2,100 MW under construction), representing an investment of more than $4 billion to the end of 2006. TransCanada has committed an additional $1.9 billion to complete the assets under construction.

  Power

  - In September 2006, the Bécancour cogeneration plant was commissioned and placed into service.
  - Construction on the Portlands Energy project commenced in September 2006.
  - In November 2006, construction on the Baie-des-Sables Cartier Wind project was completed and placed into service.
  - In November 2006, TransCanada was awarded a contract to build, own and operate a natural gas-fired power plant near the town of Halton Hills, Ontario.
  - In 2006, construction continued on the Bruce A restart and refurbishment project, which includes restart of the currently idle Units 1 and 2, and replacement of the steam generators on Unit 4.
  - 2006 included the first full year of earnings from the Sheerness PPA, acquired in December 2005 from the Alberta Balancing Pool.

  Natural Gas Storage

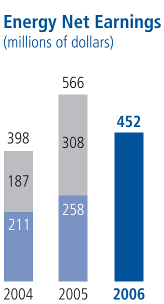
  - Construction of the Edson natural gas storage facility was substantially completed in third quarter 2006 and was placed into service on December 31, 2006.

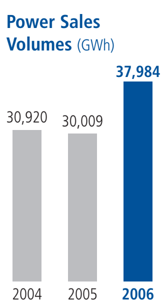
Plant Availability

- Weighted average power plant availability was 93 per cent in 2006, excluding Bruce Power, compared to 87 per cent in 2005.
- Including Bruce Power, weighted average power plant availability was 91 per cent in 2006, compared to 84 per cent in 2005.

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

	2006	2005	2004
Bruce Power	**235**	195	130
Western Power Operations	**297**	123	138
Eastern Power Operations	**187**	137	108
Natural Gas Storage	**93**	32	27
Power LP Investment	**–**	29	29
General, administrative, support costs and other	**(144)**	(129)	(127)
Operating income	**668**	387	305
Financial charges	**(23)**	(11)	(13)
Interest income and other	**5**	5	14
Income taxes	**(198)**	(123)	(95)
	452	258	211
Gain on sale of Paiton Energy	**–**	115	–
Gains related to Power LP	**–**	193	187
Net earnings	**452**	566	398





Gains related to Power LP and Paiton Energy

Energy's net earnings in 2006 were $452 million compared to $566 million in 2005. In 2005, TransCanada sold its approximate 11 per cent interest in Paiton Energy to subsidiaries of the Tokyo Electric Power Company for gross proceeds of US$103 million ($122 million) resulting in an after-tax gain of $115 million. In August 2005, TransCanada sold its ownership interest in Power LP to EPCOR Utilities Inc. (EPCOR) for net proceeds of $523 million resulting in an after-tax gain of $193 million.

Excluding the Paiton Energy and Power LP-related gains in 2005, Energy's net earnings in 2006 of $452 million increased $194 million compared to $258 million in 2005. The increase was primarily due to higher contributions from each of its existing businesses and a $23-million favourable impact on future income taxes arising from reductions in Canadian federal and provincial corporate income tax rates enacted in 2006. Partially offsetting these increases was the loss of operating income associated with the sale of the Power LP interest in 2005 and reduced earnings in 2006 due to the effect of a weaker U.S. dollar on earnings from Energy's U.S. operations.

Included in 2004 net earnings was an after-tax gain of $187 million comprising a $15-million after-tax gain on the sale of TransCanada's Curtis Palmer and ManChief power facilities to Power LP as well as $172 million of after-tax dilution gains.

Excluding the gain on the sale of Paiton Energy in 2005 and Power LP-related gains in 2005 and 2004, Energy's net earnings for the year ended December 31, 2005 of $258 million increased $47 million compared to $211 million in 2004. The increase was primarily due to higher operating income from Bruce Power and Eastern Power Operations, partially offset by a reduced contribution from Western Power Operations and lower interest income and other.

POWER PLANTS – NOMINAL GENERATING CAPACITY AND FUEL TYPE

	MW	Fuel Type
Bruce Power[1]	2,474	Nuclear
Western Power Operations		
Sheerness[2]	756	Coal
Sundance A[3]	560	Coal
Sundance B[3]	353	Coal
MacKay River	165	Natural gas
Carseland	80	Natural gas
Bear Creek	80	Natural gas
Redwater	40	Natural gas
Cancarb	27	Natural gas
	2,061	
Eastern Power Operations		
Halton Hills[4]	683	Natural gas
TC Hydro[5]	567	Hydro
OSP	560	Natural gas
Bécancour[6]	550	Natural gas
Cartier Wind[7]	458	Wind
Portlands Energy[8]	275	Natural gas
Grandview[9]	90	Natural gas
	3,183	
Total Nominal Generating Capacity	7,718	

(1) Represents TransCanada's 48.7 per cent proportionate interest in Bruce A and 31.6 per cent proportionate interest in Bruce B. Bruce A consists of four 750 MW reactors. Bruce A Unit 3 was returned to service in first quarter 2004. Bruce A Units 1 and 2 are currently being refurbished and are expected to restart in late 2009 or early 2010. Bruce B consists of four reactors which are currently in operation, with a combined capacity of approximately 3,200 MW.

(2) TransCanada directly acquires 756 MW from Sheerness through a long-term PPA.

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

(4) Currently in development.

(5) Acquired in second quarter 2005.

(6) Placed in service in third quarter 2006.

(7) First of six wind farms placed in service in fourth quarter 2006. Represents TransCanada's 62 per cent share of the total 740 MW project.

(8) Currently under construction. Represents TransCanada's 50 per cent share of this 550 MW facility.

(9) Placed in service in first quarter 2005.

ENERGY – FINANCIAL ANALYSIS

Bruce Power

On October 31, 2005, Bruce Power and the OPA completed a long-term agreement whereby Bruce A will restart and refurbish the currently idle Units 1 and 2, extend the operating life of Unit 3 by replacing its steam generators and fuel channels when required and replace the steam generators on Unit 4. As a result of an agreement between Bruce Power and the OPA, and Cameco Corporation's (Cameco) decision not to participate in the restart and refurbishment program, the Bruce A partnership was formed by TransCanada and BPC Generation Infrastructure Trust (BPC), with each owning a 48.7 per cent (2005 – 47.9 per cent) interest in Bruce A at December 31, 2006. TransCanada and BPC each incurred a net cash outlay of approximately $100 million in 2005 to acquire Cameco's interest. The remaining 2.6 per cent is owned by the Power Worker's Union Trust No. 1 and The Society of Energy Professionals Trust. The Bruce A partnership subleases the Bruce A facilities, which comprises Units 1 to 4, from Bruce B. TransCanada continues to own 31.6 per cent of Bruce B, which consists of Units 5 to 8.

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

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

	2006	2005	2004
Bruce Power (100 per cent basis)			
Revenues			
Power	**1,861**	1,907	1,563
Other[2]	**71**	35	20
	1,932	1,942	1,583
Operating expenses			
Operations and maintenance	**(912)**	(871)	(793)
Fuel	**(96)**	(77)	(68)
Supplemental rent	**(170)**	(164)	(156)
Depreciation and amortization	**(134)**	(198)	(161)
	(1,312)	(1,310)	(1,178)
Revenues, net of operating expenses	**620**	632	405
Financial charges under equity accounting[3]	**–**	(58)	(67)
	620	574	338
TransCanada's proportionate share	**228**	188	107
Adjustments	**7**	7	23
TransCanada's operating income from Bruce Power[3]	**235**	195	130
Bruce Power – Other Information			
Plant availability	**88%**	80%	82%
Sales volumes (GWh)[4]			
Bruce Power – 100 per cent	**36,470**	32,900	33,600
TransCanada's proportionate share	**13,317**	10,732	10,608
Results per MWh[5]			
Bruce A revenues	**$58**		
Bruce B revenues	**$48**		
Combined Bruce Power revenues	**$51**	$58	$47
Combined Bruce Power fuel	**$3**	$2	$2
Combined Bruce Power total operating expenses[6]	**$35**	$40	$35
Percentage of output sold to spot market	**35%**	49%	52%

(1) All information in this table includes adjustments to eliminate the effects of inter-partnership transactions between Bruce A and Bruce B.

(2) Includes fuel cost recoveries for Bruce A of $30 million for 2006 ($4 million from November 1 to December 31, 2005).

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

(4) Gigawatt hours.

(5) Megawatt hours.

(6) Net of fuel cost recoveries.

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

Combined Bruce Power prices achieved during 2006 (excluding other revenues) were $51 per MWh compared to $58 per MWh in 2005, reflecting lower prices on uncontracted volumes sold into the spot market. Bruce Power's combined operating expenses (net of fuel cost recoveries) decreased to $35 per MWh for 2006 from $40 per MWh in 2005 primarily due to increased output and higher fuel cost recoveries in 2006.

The Bruce units ran at a combined average availability of 88 per cent in 2006, compared to an 80 per cent average availability during 2005. The higher availability in 2006 was the result of 114 fewer days of planned maintenance outages as well as 65 fewer forced outage days in 2006 compared to 2005.

TransCanada's operating income from its combined investment in Bruce Power for 2005 was $195 million compared to $130 million for the same period in 2004. This increase was primarily due to higher realized prices in 2005, partially offset by higher maintenance costs, higher depreciation and lower capitalization of labour and other in-house costs following the restart of Unit 3 in first quarter 2004.

Adjustments to TransCanada's combined interest in Bruce Power's income before income taxes for 2005 were lower than in 2004 primarily due to a lower amortization of the purchase price allocated to the fair value of sales contracts in place at the time of acquisition.

Income from Bruce B is directly impacted by fluctuations in wholesale spot market prices for electricity. Income from both Bruce A and Bruce B units is impacted by overall plant availability, which in turn, is impacted by scheduled and unscheduled maintenance. To reduce its exposure to spot market prices, as at December 31, 2006, Bruce B entered into fixed price sales contracts to sell forward approximately 6,900 GWh for 2007 and 2,900 GWh for 2008. As a result of the contract with the OPA, all of the output from Bruce A was sold at a fixed price of $58.63 per MWh ($57.37 to March 31, 2006), before recovery of fuel costs from the OPA. Under the terms of the arrangement between Bruce A and the OPA, effective October 31, 2005, Bruce A receives a contract price for power generated, whereby the price is adjusted for inflation annually on April 1. Post refurbishment, prices are adjusted for any capital cost variances associated with the restart and refurbishment projects. Bruce A contract prices will not vary with changes in the wholesale price of power in the Ontario market. As part of this contract, sales from the Bruce B Units 5 to 8 are subject to a floor price of $45.99 per MWh ($45.00 to March 31, 2006), adjusted annually for inflation on April 1. 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 December 31, 2006 included no amounts received pursuant to this floor mechanism.

The overall plant availability percentage in 2007 is expected to be in the low 90s for the four Bruce B units and the mid 70s for the two operating Bruce A units. Two planned outages are scheduled for Bruce A Unit 3 with the first outage expected to last one month in second quarter 2007 and a second outage expected to last approximately two months beginning in late third quarter 2007. A one month outage of Bruce A Unit 4 is expected to commence in first quarter 2007. The only planned maintenance outage for 2007 for Bruce B is an approximately two and a half month outage for Unit 6 that began in January 2007 and is expected to be completed in early second quarter 2007.

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

The project to restart and refurbish Bruce A Units 1 and 2 was initiated in 2005. Substantial work on the project began in 2006 after Bruce received formal acceptance of its environmental assessment from the Canadian Nuclear Safety Commission in July 2006. Bruce Power has separated Units 1 and 2 from the operating reactors in Units 3 and 4. At the end of December 2006, eight replacement steam generators had been delivered and preparations made for the installation in early 2007. Work on manufacturing the Unit 4 steam generators also occurred during the year.

Bruce Power's capital program for the restart and refurbishment project is expected to total approximately $4.25 billion and TransCanada's approximately $2.125 billion share will be financed through capital contributions to 2011. A capital cost risk-and reward-sharing schedule with the OPA is in place for spending below or in excess of the $4.25 billion base case estimate. The first unit is expected to be online in late 2009, subject to approval by the Canadian Nuclear Safety Commission. Restarting Units 1 and 2, which have a capacity of approximately 1,500 MW, will boost the Bruce facilities' overall output to more than 6,200 MW. As at December 31, 2006, Bruce A had incurred $1.092 billion in costs with respect to the restart and refurbishment project.

Western Power Operations

As at December 31, 2006, Western Power Operations directly controlled approximately 2,100 MW of power supply in Alberta from its three long-term PPAs and five natural gas-fired cogeneration facilities. The Western Power Operations power supply portfolio comprises approximately 1,700 MW of low-cost, base-load coal-fired generation supply and approximately 400 MW of natural gas-fired cogeneration assets. This supply portfolio is among the lowest-cost, most competitive generation in the Alberta market area. The three long-term PPAs include the December 31, 2005 acquisition of the remaining rights and obligations of the 756 MW Sheerness PPA in addition to the Sundance A and Sundance B PPAs acquired in 2001 and 2002, respectively. The Sheerness PPA was acquired from the Alberta Balancing Pool for $585 million on December 31, 2005 and has a remaining term of approximately 14 years. The PPAs entitle TransCanada to the output capacity of these coal facilities, ending in 2017 to 2020. The success of Western Power Operations is the direct result of its two integrated functions – marketing and plant operations.

The marketing function, based in Calgary, Alberta, purchases and resells electricity sourced from the PPAs, markets uncommitted generation volumes from the cogeneration facilities, and purchases and resells power and gas to maximize the value of the cogeneration facilities. The marketing function is integral to optimizing Energy's return from its portfolio of power supply and managing risks around uncontracted volumes. A portion of TransCanada's supply is held for sale in the spot market for operational reasons and is also dependent upon the availability of acceptable contract terms in the forward market. This approach to portfolio management assists in minimizing costs in situations where TransCanada would otherwise have to purchase power in the open market to fulfil its contractual obligations. In 2006, approximately 35 per cent of power sales volumes were sold into the spot market. To reduce exposure to spot market prices of uncontracted volumes, as at December 31, 2006, Western Power Operations entered into fixed price sales contracts to sell forward approximately 10,600 GWh for 2007 and 8,300 GWh for 2008.

Plant operations consist of five natural gas-fired cogeneration power plants located in Alberta with an approximate combined output capacity of 400 MW ranging from 27 MW to 165 MW per facility. A portion of the expected output is sold under long-term contracts and the remainder is subject to fluctuations in the price of power and gas. Market heat rate is an economic measure for natural gas-fired power plants determined by dividing the average price of power per MWh by the average price of natural gas per gigajoule (GJ) for a given period. To the extent power is not sold under long-term contracts and plant fuel gas has not been purchased under long-term contracts, the higher the market heat rate, the more profitable is a natural gas-fired generating facility. Market heat rates in Alberta increased in 2006 by more than 60 per cent as a result of a decrease in average spot market natural gas prices combined with an increase in power prices. Market heat rates averaged approximately 13.5 GJ/MWh in 2006 compared to approximately 8.3 GJ/MWh in 2005. The market heat rates are expected to return to more modest levels in 2007.

All plants in Western Power Operations operated with an average plant availability in 2006 of approximately 88 per cent compared to 85 per cent in 2005. Bear Creek returned to service in mid 2006 after experiencing an unplanned outage in 2005 resulting from technical difficulties with its gas turbine. Since its return to service, it has operated as expected.

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

	2006	2005	2004
Revenues			
Power	**1,185**	715	606
Other[1]	**169**	158	120
	1,354	873	726
Commodity purchases resold			
Power	**(767)**	(476)	(377)
Other[1]	**(135)**	(104)	(64)
	(902)	(580)	(441)
Plant operating costs and other	**(135)**	(149)	(125)
Depreciation	**(20)**	(21)	(22)
Operating income	**297**	123	138

[1] Includes Cancarb Thermax and natural gas sales.

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

	2006	2005	2004
Supply			
Generation	**2,259**	2,245	2,105
Purchased			
Sundance A & B and Sheerness PPAs	**12,712**	6,974	6,842
Other purchases	**1,905**	2,687	2,748
	16,876	11,906	11,695
Contracted vs. Spot			
Contracted	**11,029**	10,374	10,705
Spot	**5,847**	1,532	990
	16,876	11,906	11,695

Operating income in 2006 of $297 million was $174 million higher than the $123 million earned in 2005. This increase was primarily due to incremental earnings from the December 31, 2005 acquisition of the 756 MW Sheerness PPA and increased margins from a combination of higher overall realized power prices and higher market heat rates on uncontracted volumes of power sold. Revenues and commodity purchases resold increased in 2006 compared to 2005 primarily due to the acquisition of the Sheerness PPA, as well as higher realized power prices. Plant operating costs and other, which include fuel gas consumed in generation, decreased due to lower natural gas prices. Purchased power volumes in 2006 increased compared to 2005 primarily due to the acquisition of the Sheerness PPA. In 2006, approximately 35 per cent of power sales volumes were sold into the spot market compared to 13 per cent in 2005.

Operating income for 2005 was $123 million or $15 million lower compared to $138 million earned in 2004. This decrease was primarily due to reduced margins in 2005 resulting from the lower market heat rates on uncontracted volumes of power generated, fee revenues earned in 2004 from Power LP and a lower contribution from Bear Creek. Revenues and commodity purchases resold increased in 2005, compared to 2004, primarily due to higher realized prices. Plant operating costs and other, which include fuel gas consumed in generation, increased due to higher operating and fuel usage costs at MacKay River resulting from a full year of operation and higher natural gas prices. Generation volumes in 2005 increased compared to 2004 primarily due to a full year of operations at MacKay River, partially offset by an unplanned outage at Bear Creek. TransCanada ceased to earn fees to manage and operate Power LP's plants with the sale of Power LP in August 2005. In 2005, approximately 13 per cent of power sales volumes were sold into the spot market compared to eight per cent in 2004.

Eastern Power Operations

Eastern Power Operations conducts its business primarily in the deregulated New England power market and in eastern Canada. In the New England market, Eastern Power Operations has established a successful marketing operation and in 2006, significantly increased its marketing presence. Growth in generation capacity in eastern Canada was also significant. The first of the six Cartier Wind wind farm projects, Baie-des-Sables, was placed in service in November 2006. The 550 MW Bécancour power plant near Trois Rivières, Québec began operations in September 2006. Including facilities that are under construction or in development, Eastern Power Operations owns approximately 3,200 MW of power generation capacity. To reduce exposure to spot market prices of uncontracted volumes, as at December 31, 2006, Eastern Power Operations had fixed price sales contracts to sell forward approximately 11,900 GWh for 2007 and 9,600 GWh for 2008.

Eastern Power Operations' success in the New England deregulated power markets is the direct result of a knowledgeable, region-specific marketing operation which is conducted through its wholly owned subsidiary, TransCanada Power Marketing Ltd. (TCPM), located in Westborough, Massachusetts. TCPM has firmly established itself as a leading energy provider and marketer in the region and is focused 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. TCPM is a full requirement electric service provider offering varied products and services to assist customers in managing their power supply and power prices in volatile deregulated power markets.

Eastern Power Operations' current operating power generation assets are TC Hydro, OSP, Bécancour, Grandview and the Baie-des-Sables wind farm. The TC Hydro assets include 13 hydroelectric stations housing 39 hydroelectric generating units on the Connecticut River System in New Hampshire and Vermont and the Deerfield River System in Massachusetts and Vermont. Water flows in 2006 through the hydro assets were above long-term averages as a result of higher precipitation in the areas surrounding the river systems. These higher than expected water flows were partially offset by lower than expected power prices in the market during 2006.

OSP is a 560 MW natural gas-fired plant located in Rhode Island, owned 100 per cent by TransCanada. In 2006, plant availability and utilization of the OSP facility improved compared to 2005. OSP realized lower overall natural gas fuel supply costs in 2006 compared to 2005 due to lower spot prices of natural gas as a result of a restructuring of its long-term gas supply contracts which took place in 2005.

Bécancour is a 550 MW natural gas-fired cogeneration plant located near Trois Rivières, Québec. After nearly three years of planning and construction, and an investment of approximately $500 million, Bécancour was placed in service in September 2006. The facility is capable of generating approximately 4,500 GWh of power per year. Under long-term contracts, the facility will supply electricity to Hydro-Québec to help meet growing electricity demands and provide an important source of steam for industrial processes.

Grandview is a 90 MW 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 Operations' growing presence in eastern Canada is represented by the development of the Portlands Energy project and the Halton Hills power plant and construction in 2007 on the second and third of six proposed wind farms of the Cartier Wind project.

In November 2006, the Baie-des-Sable wind farm went into commercial operation and is currently one of the largest wind farms in Canada, providing up to 110 MW of power to the Hydro Québec grid. Baie-des-Sable is the first phase of a multi-phase, multi-year project called the Cartier Wind project that is owned 62 per cent by TransCanada. The other phases of Cartier Wind will continue, subject to future appropriations and approvals, through 2012 at six different locations in the Gaspé region of Québec and capacity is expected to total 740 MW when all phases are complete. Commitments are in place for the 100 MW Anse à Valleau phase and the 100 MW Carleton phase. Anse à Valleau is presently under construction and is expected to be placed into commercial service during third quarter 2007 and construction at Carleton will commence in late 2007 with expected commercial service to begin in fourth quarter 2008.

In September 2006, Portlands Energy, a 50/50 partnership between Ontario Power Generation and TransCanada, announced that it had signed a 20-year ACES contract with the OPA to construct a 550 MW high efficiency, combined-cycle natural gas generation plant to be located in downtown Toronto, Ontario. The capital cost of the Portlands Energy project is estimated to be approximately $730 million and is expected to be operational in simple cycle mode, delivering 340 MW of electricity to the City of Toronto, beginning June 1, 2008. Upon the expected completion in second quarter 2009, the Company anticipates that this plant will provide up to 550 MW of power under the ACES contract.

In November 2006, TransCanada announced that it had been awarded a 20-year Greater Toronto Area (GTA) West Trafalgar Clean Energy Supply contract by the OPA to build, own and operate a 683 MW natural gas-fired power plant near the town of Halton Hills, Ontario. TransCanada expects to invest approximately $670 million in the Halton Hills Generating Station, which is anticipated to be in service in second quarter 2010.

On June 15, 2006, the FERC approved a settlement agreement to implement a newly-designed Forward Capacity Market (FCM) for power generation in the New England power markets. The FCM design is intended to promote investment in new and existing power resources needed to meet the growing consumer demand and maintain a reliable power system. The settlement agreement provides for a multi-year transition period beginning in December 2006 and ending in 2010, whereby fixed payments, ranging from US$3.05 to US$4.10 per kilowatt-month, will be made to owners of existing installed capacity. These payments will be reduced in the event of facility-forced outages. Eastern Power Operations' 560 MW OSP plant and 567 MW TC Hydro generation facilities are eligible to receive payments during the transition period starting in December 2006. Under the new FCM design, Independent System Operator New England will project the needs of the power system three years in advance and then hold an annual auction to purchase power resources to satisfy a region's future needs. June 1, 2010 is identified as the first period for which suppliers would receive payments pursuant to the FCM auction mechanism.

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

	2006	2005	2004
Revenues			
Power	**789**	505	535
Other[2]	**292**	412	238
	1,081	917	773
Commodity purchases resold			
Power	**(379)**	(215)	(288)
Other[2]	**(257)**	(373)	(211)
	(636)	(588)	(499)
Plant operating costs and other	**(226)**	(167)	(146)
Depreciation	**(32)**	(25)	(20)
Operating income	**187**	137	108

(1) Curtis Palmer is included until April 30, 2004.

(2) Other includes natural gas.

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

	2006	2005	2004
Supply			
Generation	**4,700**	2,879	1,467
Purchased	**3,091**	2,627	4,731
	7,791	5,506	6,198
Contracted vs. Spot			
Contracted	**7,374**	4,919	6,055
Spot	**417**	587	143
	7,791	5,506	6,198

(1) Curtis Palmer is included until April 30, 2004.

Operating income for 2006 was $187 million or $50 million higher than the $137 million earned in 2005. This increase is primarily due to incremental income from the full year of ownership of the TC Hydro assets, the placing into service of the 550 MW Bécancour cogeneration plant in September 2006, a $10-million after-tax one-time restructuring payment in first quarter 2005 from OSP to its natural gas fuel suppliers, and higher overall margins on power sales volumes in 2006. Partially offsetting these increases was the negative impact of a weaker U.S. dollar in 2006 compared to 2005.

Eastern Power Operations' revenues in 2006 were $1,081 or $164 million higher than the $917 million earned in 2005. This is due to the placing into service of the Bécancour facility, increased sales volumes to commercial and industrial customers, and higher realized prices. Other revenue and other commodity purchases resold decreased year-over-year as a result of a reduction in the quantity of natural gas purchased and resold under the new natural gas supply contracts at OSP. Power commodity purchases resold were higher in 2006 due to the impact of higher purchased volumes, combined with higher prices for purchased power. Purchased power volumes were higher in 2006 due to higher contracted sales volumes, partially offset by the increased power generation from the purchase of the TC Hydro assets as volumes generated from the TC Hydro assets reduced the requirement to purchase power to fulfil contractual sales obligations. Plant operating costs and other in 2006 were higher primarily due to the full year of operations of the TC Hydro assets as well as the placing into service of the Bécancour and Baie-des-Sables facilities.

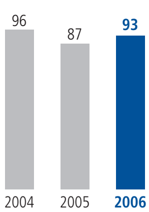
Operating income for 2005 was $137 million or $29 million higher than the $108 million earned in 2004. The incremental income from the acquisition of the TC Hydro assets and income from the Grandview cogeneration facility were the primary reasons for this increase. Partially offsetting these increases were the contract restructuring payment made by OSP in first quarter 2005, a $10-million after-tax reduction in income as a result of the sale of Curtis Palmer to Power LP in April 2004, and a loss of operating income primarily associated with the expiration of certain long-term sales contracts in 2004.

Power LP Divestiture

On August 31, 2005, TransCanada sold all of its interest in Power LP to EPCOR for net proceeds of $523 million resulting in an after-tax gain of $193 million. This divestiture included approximately 14.5 million partnership units, representing approximately 30.6 per cent of the outstanding units, 100 per cent of the general partnership of Power LP, and management and operations agreements governing the ongoing operation of Power LP's generation assets. TransCanada's investment in Power LP generated operating income of $29 million in each of 2005 and 2004.

Plant Availability

Plant Availability excluding Bruce Power
(per cent)



Weighted average power plant availability for all plants, excluding Bruce Power, was 93 per cent in 2006 compared to 87 per cent in 2005 and 96 per cent in 2004. Plant availability represents the percentage of time in the year that the plant is available to generate power, whether actually running or not, and is reduced by planned and unplanned outages. Western Power Operations' plant availability was impacted in 2006 and 2005 by an unplanned outage at Bear Creek, which returned to service in August 2006. An additional planned outage was taken in 2005 at the MacKay River facility, further decreasing the plant availability for Western Power Operations in 2005. Availability of 95 per cent was achieved in Eastern Power Operations in 2006. Availability was lower in 2005 as a result of OSP experiencing two significant outages.

Weighted Average Plant Availability[1]
Year ended December 31

	2006	2005	2004
Bruce Power[2]	**88%**	80%	82%
Western Power Operations[3]	**88%**	85%	95%
Eastern Power Operations[4]	**95%**	83%	95%
Power LP investment[5]	**–**	94%	97%
All plants, excluding Bruce Power investment	**93%**	87%	96%
All plants	**91%**	84%	90%

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

(2) Bruce A Unit 3 is included effective March 1, 2004.

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

(4) TC Hydro, Bécancour and Cartier Wind's Baie-des-Sables are included in Eastern Power Operations effective April 1, 2005, September 17, 2006 and November 21, 2006, respectively.

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

Natural Gas Storage

With the completion of the 50 Bcf Edson storage facility, TransCanada became one of the largest natural gas storage providers in western Canada in 2006. TransCanada owns or controls 138 Bcf of natural gas storage capacity in Alberta, which includes a 60 per cent ownership interest in CrossAlta Gas Storage & Services Ltd. (CrossAlta), an independently operated 50 Bcf storage facility. TransCanada also has contracts for 38 Bcf in 2007 of long-term, Alberta-based storage capacity from a third party.

Natural Gas Storage Capacity

	Working Gas Storage Capacity (Bcf)	Maximum Injection/ Withdrawal Capacity (mmcf/d)
Edson	50	725
CrossAlta	50	480
Third Party Storage (for 2007)	38	630
	138	1,835

TransCanada believes the market fundamentals for natural gas storage are strong. The additional gas storage capacity will help balance seasonal and short-term supply and demand, and provide flexibility to the supply of natural gas to Alberta and North America. The increasing seasonal imbalance in North American natural gas supply and demand has increased gas price volatility and the demand for storage service. Alberta-based storage will continue to serve market needs and could play an important role should northern gas be connected to North American markets. Energy's natural gas storage business operates independently from TransCanada's regulated natural gas transmission business.

TransCanada manages its exposure to seasonal gas price spreads by hedging storage capacity with a portfolio of third party storage contracts and gas purchases and sales. TransCanada offers a broad range of flexible injection and withdrawal storage alternatives specific to customer needs in multi-year contract terms. In addition to term gas storage contracts, TransCanada actively manages its storage assets with a combination of gas hedging activities and short-term third party contracts to take advantage of market opportunities and meet unique customer needs. Market volatility frequently creates arbitrage opportunities and TransCanada offers market centre solutions to capture these short-term price movements. Market centre products consist of short-term deliver-redeliver contracts, parking, peak-day supply and other related services.

The Edson storage operation is an underground natural gas storage facility consisting of a single depleted reservoir, the Viking D pool, a central processing facility and associated pipeline gathering system. The plant is located near Edson, Alberta. The Viking D pool produced approximately 71 Bcf of gas over its productive life from the 1980's to early 2004. The natural gas storage facility is expected to have a working natural gas capacity of approximately 50 Bcf, is connected to TransCanada's Alberta System and has a central processing system capable of maximum injection and withdrawal rates of 725 mmcf/d of natural gas. Construction of the Edson facility was substantially completed in 2006 and placed into service on December 31, 2006.

The CrossAlta storage facility is a 50 Bcf natural gas storage facility located near the town of Crossfield, Alberta. CrossAlta is a joint venture with BP Canada that has been in operation since 1994 and markets its own storage capacity and services. Gas is stored in a depleted gas reservoir that has been used to produce gas at this location since the 1960s. CrossAlta successfully completed a major expansion in the fall of 2005. The expansion increased total working natural gas capacity from 40 Bcf to 50 Bcf, with the potential to expand to 80 Bcf. The storage facility has a peak withdrawal capacity of 480 mmcf/d with the potential to expand to 1,000 mmcf/d.

The third-party natural gas storage capacity contracted by TransCanada is also located in Alberta. The capacity has increased annually from 18 Bcf in 2005 to 28 Bcf in 2006 and is expected to reach 38 Bcf in 2007. The contract expires in 2030, subject to mutual early termination rights in 2015.

Natural Gas Storage operating income of $93 million for the year ended December 31, 2006 increased $61 million and $66 million, compared to 2005 and 2004, respectively. The increases were primarily due to higher contributions from CrossAlta as a result of increased capacity and higher natural gas storage spreads, and income from contracted third-party natural gas storage capacity. The Edson facility did not contribute to earnings in 2006 as the asset was placed into service on December 31, 2006.

LNG Projects

TransCanada continues to pursue two LNG proposals, the Broadwater and Cacouna projects. Broadwater, a joint venture with Shell US Gas & Power LLC (Shell), is a proposed LNG facility in the New York and Connecticut State waters in Long Island Sound. The Broadwater terminal would be capable of receiving, storing, and regassifying imported LNG with an average send-out capacity of approximately 1 Bcf/d of natural gas. TransCanada, on behalf of Broadwater, filed an application in January 2006 with the FERC for approval of the project. The U.S. Coast Guard issued a report which determined that the waterways associated with the project are suitable if additional measures are implemented to manage the safety and security risks associated with the project. Broadwater's application to the New York Department of State for a determination that the project is consistent with New York's coastal zone policies was deemed complete by the state in November 2006. Also in November, the FERC issued a Draft Environmental Impact Statement to fulfil the requirements of the *National Environmental Policy Act* and the FERC's implementing regulations. The Statement concludes that with strict adherence to federal and state permit requirements and regulations, Broadwater's proposed mitigation measures and the FERC's recommendations, the Broadwater project will not result in a significant impact on the environment. At December 31, 2006, the Company had capitalized $31 million related to Broadwater.

Cacouna, a joint venture with Petro-Canada, is a proposed LNG project at the Gros Cacouna harbour on the St. Lawrence River in Québec. The proposed terminal would be capable of receiving, storing, and regassifying imported LNG with an average throughput capacity of approximately 500 mmcf/d of natural gas. A public hearing on the Cacouna facility was held in May and June 2006. In December 2006, the Québec government released the report of the Joint Commission on the Cacouna Energy project, which contained several recommendations and opinions but appears to be favourable to the project. TransCanada continues to work towards gaining regulatory approval and, if the necessary approvals are obtained, the facility is anticipated to be in service by 2010.

ENERGY – OPPORTUNITIES AND DEVELOPMENTS

TransCanada is committed to growing its North American Energy business through acquisitions and development of greenfield opportunities in markets it knows and has a competitive advantage – primarily western Canada, the northwestern U.S., eastern Canada and the northeastern U.S. The North American energy industry is expansive and will provide many opportunities for greenfield growth in power generation, power infrastructure projects and natural gas storage. In addition to greenfield growth opportunities, TransCanada will endeavour to pursue acquisitions resulting from industry and corporate restructurings and corporate bankruptcies. In addition to natural gas-fired facilities, Energy will focus on generation sourced from wind, hydro and nuclear. Its diverse power supply portfolio will continue to include low-cost, base-load facilities with low operating costs and high reliability, which may be underpinned by secure long-term contracts.

The Bécancour natural gas-fired cogeneration power plant and the first of six wind farms in the Cartier Wind project, both located in Québec, were placed in service in 2006. The remaining five Cartier Wind farms will continue, although certain phases of the project are subject to future appropriations and approvals. Construction began in 2006 on Portlands Energy's 550 MW, combined cycle natural gas generation plant in downtown Toronto. In 2006, TransCanada also announced that it had been awarded a 20-year GTA West Trafalgar Clean Energy Supply contract by the OPA to build, own and operate a 683 MW natural gas-fired power plant near the town of Halton Hills, Ontario which is expected to be completed in 2010. The Bruce A restart and refurbishment continued in 2006 and Units 1 and 2 are expected to be restarted in late 2009 or early 2010.

Construction of the 50 Bcf Edson natural gas storage facility was substantially completed and the facility placed into service on December 31, 2006.

TransCanada is pursuing two LNG projects, Broadwater and Cacouna. Broadwater is a joint project with Shell to build a 1 Bcf/d LNG facility in the waters of the Long Island Sound. Cacouna is a joint venture with Petro-Canada to construct a 500 mmcf/d LNG facility at Gros Cacouna.

ENERGY – BUSINESS RISKS

Fluctuating Power and Natural Gas Market Prices

TransCanada operates in competitive, generally deregulated power and natural gas markets in North America. Volatility in power and natural gas prices is caused by various 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 owned assets. The Company's risk management practices are described further in the section on Risk Management. See the "Uncontracted Volumes" section below.

Uncontracted Volumes

Energy has certain uncontracted power sales volumes in Western and Eastern Power Operations and through its investment in Bruce Power. Sale of uncontracted power volumes into the spot market is subject to market price volatility which directly impacts earnings. Bruce B has a significant amount of uncontracted volumes sold into the wholesale power spot market while 100 per cent of the Bruce A output is sold to the OPA under fixed-price contract terms. 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 with varying terms.

Plant Availability

Maintaining plant availability is essential to the continued success of the Energy business. Plant operating risk is mitigated through a commitment to TransCanada's operational excellence strategy that provides low-cost, reliable operating performance at each of the Company's facilities. Unexpected plant outages and/or 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 enable TransCanada to meet its contractual obligations.

Weather

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

Hydrology

Energy's power business is subject to hydrology risk with its 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 program in Ontario and Québec, including its investment in Bruce Power, is subject to execution and capital cost risk. At Bruce Power, Bruce A's four unit restart and refurbishment program is also subject to a capital cost risk- and reward-sharing mechanism with the OPA.

Asset Commissioning

Recently constructed assets including Edson, Baie-des-Sables and Bécancour were all placed in service during 2006 and are in the first full year of operation in 2007. Although all of TransCanada's newly constructed assets go through rigorous acceptance testing prior to being placed in service, there is a risk that these assets may have lower than expected availability or performance, especially in the assets' first year of operations.

Power Regulatory

TransCanada operates in both regulated and deregulated power markets. As electricity markets evolve across North America, there is the potential for regulatory bodies to implement new rules that could negatively impact TransCanada as a generator and marketer of electricity. These may be in the form of market rule changes, price caps, emission controls, unfair cost allocations to generators or attempts to control the wholesale market by encouraging new plant construction. TransCanada continues to monitor regulatory issues and reform as well as participate in and lead discussions around these topics.

For information on management of risks with respect to the Energy business, refer to the "Risks and Risk Management" section of this MD&A.

ENERGY – OUTLOOK

In Energy, net earnings in 2007 are expected to approximate or be slightly lower than 2006 net earnings due to the non-recurring $23-million future tax benefit in 2006 arising from reductions in federal and provincial income tax rates. Operating income is expected to be relatively consistent with 2006, although this is very dependent on commodity prices in each region as well as other factors such as hydrology and storage spreads. TransCanada's operating income from its investment in Bruce B can be significantly impacted by the effect, on uncontracted output, of changes in spot market prices for power. Excluding any changes in spot market prices for 2007 compared to 2006, Bruce Power's operating income is expected to decline in 2007 compared to 2006, reflecting lower projected generation volumes and higher operating costs resulting from an increase in planned outages in 2007. Western Power Operations' operating income in 2007 is expected to approximate 2006. Although TransCanada has sold forward significant output from its Alberta PPAs and power plants, Western Power Operations' operating income in 2007 can be significantly impacted by changes in the spot market price of power and market heat rates in Alberta. Eastern Power Operations' operating income is expected to increase in 2007 primarily due to a full year of operations for both the Bécancour natural gas-fired cogeneration facility and the first of six wind farms of the Cartier Wind project as well as the positive impact of the NEPOOL forward capacity payments received by OSP and TC Hydro commencing December 1, 2006. Gas Storage's operating income is expected to increase in 2007 over 2006 primarily due to the placing into service of the Edson facility at the end of 2006, partially offset by expected lower storage spreads.

The earnings outlook for Energy may be affected by factors such as fluctuating market prices for power and natural gas, market heat rates, sales of uncontracted power volumes, natural gas storage spreads, plant availability, regulatory changes, weather, currency movements, and overall stability of the energy industry. See "Energy – Business Risks" for a complete discussion of these factors.

CORPORATE

CORPORATE RESULTS-AT-A-GLANCE

Year ended December 31 (millions of dollars)

	2006	2005	2004
Indirect financial charges and non-controlling interests	**136**	130	79
Interest income and other	**(43)**	(29)	(34)
Income taxes	**(132)**	(65)	(43)
Net (earnings)/expenses, after tax	**(39)**	36	2

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 primarily associated with the debt and preferred securities related to the Company's wholly owned pipelines. Indirect financial charges, including the related foreign exchange impacts, primarily reside in Corporate. These costs are directly impacted by the amount of debt that TransCanada maintains and the degree to which TransCanada is impacted by fluctuations in interest rates and foreign exchange.
- ***Interest Income and Other*** Interest income includes interest earned on invested cash balances and income tax refunds. Gains and losses on foreign exchange related to working capital in Corporate are also included in interest income and other.
- ***Income Taxes*** Income tax recoveries includes income taxes calculated on Corporate's net expenses as well as income tax refunds and adjustments.

Net earnings, after tax, in Corporate were $39 million in 2006 compared to net expenses of $36 million in 2005 and $2 million in 2004.

The increase of $75 million in net earnings in 2006, compared to 2005, was primarily due to a $50-million income tax benefit related to the resolution of certain income tax matters reported in third quarter 2006, $12 million of income tax refunds and related interest income in fourth quarter 2006, and a $10-million favourable impact on future income taxes arising from reductions in Canadian federal and provincial corporate income tax rates in second quarter 2006. In addition, net earnings in 2006 were positively impacted by the effect of a weaker U.S. dollar.

The increase of $34 million in net expenses in 2005 compared to 2004 was primarily due to increased interest expense on higher average long-term debt and commercial paper balances in 2005 as well as the release in 2004 of previously established restructuring provisions. Income tax refunds and positive tax adjustments were comparable in 2004 and 2005.

Corporate's net expenses are expected to be higher in 2007 compared to 2006 primarily due to income tax refunds and positive income tax adjustments realized in 2006 that are not expected to recur in 2007. Financing costs associated with the acquisition of ANR are expected to increase net expenses in Corporate in 2007. In addition, Corporate's results could be impacted by debt levels, interest rates, foreign exchange movements and income tax refunds and adjustments. The performance of the Canadian dollar relative to the U.S. dollar will either positively or negatively impact Corporate's results, although this impact is mitigated by offsetting exposures in certain of TransCanada's other businesses as well as through the Company's hedging activities.

DISCONTINUED OPERATIONS

In 2006, the Company recognized income from discontinued operations of $28 million, reflecting bankruptcy settlements with Mirant related to TransCanada's Gas Marketing business divested in 2001. In 2005, the Company reviewed the provision for loss on discontinued operations and concluded that the provision was adequate. In 2004, $52 million was recognized in income which related to the original $102 million after-tax deferred gain included in the sale of the Gas Marketing business.

LIQUIDITY AND CAPITAL RESOURCES

Summarized Cash Flow
Year ended December 31 (millions of dollars)

	2006	2005	2004
Funds generated from operations	**2,378**	1,951	1,703
(Increase)/decrease in working capital	**(303)**	(49)	29
Net cash provided by operations	**2,075**	1,902	1,732
Net cash used in investing activities	**(2,116)**	(1,336)	(1,648)
Net cash provided by/(used in) financing activities	**219**	(556)	(150)
Effect of foreign exchange rate changes on cash and short-term investments	**9**	11	(87)
Increase/(decrease) in cash and short-term investments	**187**	21	(153)
Cash and short-term investments – beginning of year	**212**	191	344
Cash and short-term investments – end of year	**399**	212	191

HIGHLIGHTS

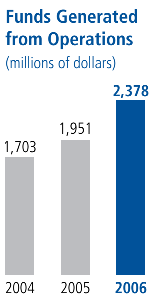
Investing Activities

- At December 31, 2006, total capital expenditures and acquisitions, including assumed debt, were approximately $7.0 billion over the past three years.

Dividend

- TransCanada's Board of Directors declared a $0.34 per common share dividend for the quarter ending March 31, 2007.
- In January 2007, TransCanada's Board of Directors authorized the issue of common shares from treasury at a two per cent discount under the Company's DRP, beginning with the dividend payable April 30, 2007 to shareholders of record at March 30, 2007.

Funds Generated from Operations

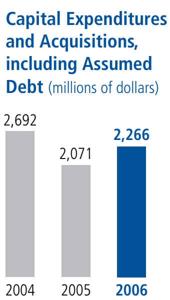


Funds generated from operations were $2.4 billion in 2006 compared to $2.0 billion and $1.7 billion, in 2005 and 2004, respectively. The increase in 2006 compared to 2005 was mainly a result of higher net income, excluding gains, and lower current income tax expense. The Pipelines business was the primary source of funds generated from operations for each of the three years. As a result of rapid growth in the Energy business in the last few years, the Energy segment's funds generated from operations increased in 2006 compared to the two prior years.

At December 31, 2006, TransCanada's ability to generate adequate amounts of cash in the short term and the long term when needed, and to maintain financial capacity and flexibility to provide for planned growth, was consistent with recent years.

Investing Activities

Capital expenditures, totalled $1,572 million in 2006 compared to $754 million in 2005 and $530 million in 2004, respectively. Expenditures in all three years related primarily to construction of new power plants and natural gas storage facilities in Canada as well as maintenance and capacity capital in the Pipelines business.



During 2006, PipeLines LP acquired an additional 49 per cent interest in Tuscarora, subject to closing adjustments, for US$100 million, in addition to indirectly assuming US$37 million of debt. In addition, PipeLines LP 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. At December 31, 2006, TransCanada held a 13.4 per cent interest in PipeLines LP. In 2006, TransCanada sold its 17.5 per cent general partner interest in Northern Border Partners, L.P. for proceeds of $23 million.

During 2005, TransCanada acquired the remaining rights and obligations of the Sheerness PPA for $585 million, invested a net cash outlay of $100 million in Bruce A as part of the Bruce Power reorganization, purchased the TC Hydro assets from USGen New England, Inc. (USGen) for US$503 million and acquired an additional 3.52 per cent ownership interest in Iroquois for US$14 million. TransCanada sold its ownership interest in Power LP for proceeds of $444 million, net of current tax, its approximate 11 per cent ownership interest in Paiton Energy for proceeds of $125 million, net of current tax, and PipeLines LP units for proceeds of $102 million, net of current tax.

During 2004, TransCanada acquired GTN for US$1.2 billion, excluding assumed debt of approximately US$500 million, and sold the ManChief and Curtis Palmer power facilities to Power LP for US$403 million, excluding closing adjustments.

Financing Activities

On February 22, 2007, the Company completed its acquisition of ANR and an additional interest in Great Lakes which was financed through issuance of a combination of debt and equity. At the same time, PipeLines LP completed the acquisition of its interest in Great Lakes which was financed through the issuance of a combination of debt and equity. These financings are summarized in the section "Subsequent Events" in this MD&A.

On February 15, 2007, the Company retired $275 million of 6.05 per cent medium term notes. In 2006, TransCanada retired long-term debt of $729 million and reduced its notes payable by $495 million. In January 2006, the Company issued $300 million of 4.3 per cent five-year medium-term notes due 2011. In March 2006, the Company issued US$500 million of 5.85 per cent 30-year senior unsecured notes due 2036. In October 2006, TransCanada issued $400 million of 4.65 per cent ten-year medium-term notes due 2016.

In April 2006, PipeLines LP borrowed US$307 million under its unsecured credit facility to finance the cash portion of the purchase price of its acquisition of an additional 20 per cent interest in Northern Border. In December 2006, the credit facility was repaid in full and replaced with a US$410 million syndicated revolving credit and term loan agreement, of which US$397 million was drawn as at December 31, 2006. Borrowings under the credit and term loan agreement will bear interest at the London interbank offered rate plus an applicable margin.

In 2005, TransCanada retired long-term debt of $1,113 million and increased its notes payable by $416 million. In June 2005, Gas Transmission Northwest Corporation (GTNC) redeemed all of its outstanding US$150 million 7.8 per cent Senior Unsecured Debentures (Debentures) and US$250 million 7.1 per cent Senior Unsecured Notes. As a consequence, upon application by GTNC, the Debentures were de-listed from the New York Stock Exchange and GTNC no longer has any securities registered under U.S. securities laws. In June 2005, GTNC also completed a US$400-million multi-tranche private placement of senior debt with a weighted average interest rate of 5.28 per cent and weighted average life of approximately 18 years. In 2005, TransCanada also issued $300 million of 5.1 per cent medium-term notes due 2017 under the Company's Canadian shelf prospectus.

In 2004, TransCanada retired long-term debt of $1,005 million. The Company issued $200 million of 4.1 per cent medium-term notes due 2009, US$350 million of 5.6 per cent senior unsecured notes due 2034 and US$300 million of 4.875 per cent senior unsecured notes due 2015. The Company increased its notes payable by $179 million during 2004.

Financing activities included a net reduction in TransCanada's proportionate share of non-recourse debt of joint ventures of $14 million in 2006 compared to $42 million in 2005 and a net increase of $105 million in 2004.

Dividends on common shares amounting to $617 million were paid in 2006 compared to $586 million in 2005 and $552 million in 2004.

In January 2007, TransCanada's Board of Directors approved an increase in the quarterly common share dividend payment to $0.34 per share from $0.32 per share for the quarter ending March 31, 2007. This was the seventh consecutive year of dividend increase since the $0.20 per share declared in fourth quarter 2000, which represents a 70 per cent increase in the dividend rate since 2000.

In January 2007, TransCanada's Board of Directors authorized the issue of common shares from treasury at a discount to participants in the Company's DRP. Under this plan, eligible shareholders may reinvest their dividends to obtain additional TransCanada common shares. Previously, shares purchased through the DRP were purchased by TransCanada on the open market and provided to DRP participants at cost. Commencing with the dividend payable in April 2007, the shares will be provided to the participants at a two per cent discount. The Company reserves the right to alter the discount or return to purchasing shares on the open market at any time.

At December 31, 2006, total credit facilities of $2.1 billion were available to support the Company's commercial paper program and for general corporate purposes. Of this total, $1.5 billion is a committed five-year term syndicated credit facility. The facility is extendible on an annual basis and is revolving. In December 2006, the maturity date of this facility was extended to December 2011. The remaining amounts are either demand or non-extendible facilities.

At December 31, 2006, TransCanada had used approximately $190 million of its total lines of credit for letters of credit to support ongoing commercial arrangements. If drawn, interest on the lines of credit would be charged at prime rates of Canadian chartered and U.S. banks or at other negotiated financial bases.

TransCanada's issuer rating assigned by Moody's Investors Service (Moody's) is A3 with a stable outlook. TransCanada PipeLines Limited's (TCPL) senior unsecured debt is rated A, with a stable outlook, by Dominion Bond Rating Service Limited (DBRS); A2, with a stable outlook, by Moody's; and A−, with a negative outlook, by Standard and Poor's (S&P). DBRS had placed TCPL's rating under review with developing implications on December 22, 2006 as a result of the announcement of the acquisition of ANR and Great Lakes. Moody's and S&P reaffirmed their ratings after the announcement. On February 22, 2007, DBRS confirmed their rating and outlook for TCPL and removed the rating from being under review.

CONTRACTUAL OBLIGATIONS

Obligations and Commitments

Total long-term debt at December 31, 2006 was approximately $11.5 billion compared to approximately $10.0 billion at December 31, 2005. TransCanada's share of total debt of joint ventures at December 31, 2006 was $1.3 billion compared to $1.0 billion at December 31, 2005. Total notes payable at December 31, 2006, including TransCanada's proportionate share of the notes payable of joint ventures, were $467 million compared to $962 million at December 31, 2005. The security provided by each joint venture, except for the capital lease obligation at Bruce Power, is limited to the rights and assets of that joint venture and does not extend to the rights and assets of TransCanada, except to the extent of TransCanada's investment. TransCanada has provided certain pro-rata guarantees related to the capital lease obligations of Bruce Power.

CONTRACTUAL OBLIGATIONS

Year ended December 31 (millions of dollars)

		Payments Due by Period			
	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt	12,531	750	1,605	1,803	8,373
Capital lease obligations	250	8	20	28	194
Operating leases[1]	919	39	83	84	713
Purchase obligations	11,871	2,707	3,274	1,403	4,487
Other long-term liabilities reflected on the balance sheet	304	10	23	27	244
Total contractual obligations	25,875	3,514	5,005	3,345	14,011

(1) Represents future annual payments, net of sub-lease receipts, for various premises, services, equipment and a natural gas storage facility. The operating lease agreements for premises expire at various dates through 2016, with an option to renew certain lease agreements for three to five years. The operating lease agreement for the natural gas storage facility expires in 2030 with lessee termination rights every fifth anniversary commencing in 2010 and with the lessor having the right to terminate the agreement every five years commencing in 2015.

At December 31, 2006, scheduled principal repayments and interest payments related to long-term debt and the Company's proportionate share of the long-term debt and capital lease obligations of joint ventures are as follows.

PRINCIPAL REPAYMENTS

Year ended December 31 (millions of dollars)

		Payments Due by Period			
	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt	11,503	616	1,396	1,536	7,955
Long-term debt of joint ventures	1,028	134	209	267	418
Capital lease obligations	250	8	20	28	194
Total principal repayments	12,781	758	1,625	1,831	8,567

INTEREST PAYMENTS
Year ended December 31 (millions of dollars)

		Payments Due by Period			
	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Interest payments on long-term debt	11,963	888	1,625	1,411	8,039
Interest payments on long-term debt of joint ventures	687	86	160	105	336
Total interest payments	12,650	974	1,785	1,516	8,375

At December 31, 2006, the Company's future purchase obligations are approximately 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]	648	178	257	126	87
Other	92	92	–	–	–
Energy					
Commodity purchases[3]	8,807	1,396	2,051	1,101	4,259
Capital expenditures[4]	1,875	854	842	118	61
Other[5]	374	169	90	42	73
Corporate					
Information technology and other	75	18	34	16	7
Total purchase obligations	11,871	2,707	3,274	1,403	4,487

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

(2) Rates are based on known 2007 levels. Beyond 2007, 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) 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.

(4) Represents primarily estimated capital expenditures to construct new Energy projects. Amounts are estimates and are subject to variability based on timing of construction and project enhancements. The Company expects to fund these projects with cash from operations and, if necessary, new debt.

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

During 2007, TransCanada expects to make funding contributions to the Company's pension plans and other benefit plans in the amount of approximately $44 million and $5 million, respectively. The expected decrease in total pension and post-retirement benefits funding in 2007 from $104 million in 2006 is primarily attributed to the actual return on plan assets for 2006 exceeding investment performance expectations as well as additional company funding in 2006. These decreases were partially offset by increases in pension-funding liabilities due to plan experience being different from expected. During 2007, TransCanada's proportionate share of expected funding contributions to be made by joint ventures to their respective pension plans and other benefit plans is approximately $33 million and $3 million, respectively.

TransCanada has guaranteed the performance of all obligations of PipeLines LP with respect to its acquisition of a 46.45 per cent interest in Great Lakes pursuant to the purchase agreement.

TransCanada and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are or were transacted at market prices and in the normal course of business.

Bruce Power
Included in Energy's capital expenditures in the previous table are TransCanada's share of Bruce A's commitments to third party suppliers for the next four years for the restart and refurbishment of the currently idle Units 1 and 2, extending the operating life of Unit 3 by replacing its steam generators and fuel channels when required, and the replacement of the steam generators on Unit 4, as follows.

Year ended December 31 (millions of dollars)

2007	450
2008	164
2009	71
2010	1
2011	–
	686

In addition to the Bruce restart and refurbishment, the Company is committed to capital expenditures of approximately $1.2 billion for the construction of its Halton Hills, Portlands Energy and remaining Cartier Wind projects, subject to future appropriations and approvals.

Aboriginal Pipeline Group
On June 18, 2003, the Mackenzie Delta gas producers, the APG and TransCanada reached an agreement which governs TransCanada's role in the MGP project. The project would result in a natural gas pipeline being constructed from Inuvik, Northwest Territories, to the northern border of Alberta, where it would connect with the Alberta System. Under the agreement, TransCanada agreed to finance the APG for its one-third share of pre-development costs. These costs are currently forecasted to be approximately $145 million by the end of 2007.

Guarantees
TransCanada had no outstanding guarantees related to the long-term debt of unrelated third parties at December 31, 2006.

The Company, together with Cameco and BPC, has severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, operator licenses, the lease agreement, and contractor services. The terms of the guarantees range from 2007 to 2018.

As part of the reorganization of Bruce Power in 2005, including the formation of Bruce A and the commitment to restart and refurbish the Bruce A units, the Company, together with BPC, severally guaranteed one-half of certain contingent financial obligations of Bruce A related to the refurbishment agreement with the OPA and cost sharing and sublease agreements with Bruce B. The terms of the guarantees range from 2019 to 2036.

TransCanada's share of the net exposure under these Bruce Power guarantees at December 31, 2006 was estimated to be approximately $586 million of a calculated maximum of $658 million. The current carrying amount of the liability related to these guarantees is nil and the fair value is approximately $17 million.

TransCanada has guaranteed the equity undertaking of a subsidiary which supports the payment, under certain conditions, of principal and interest on US$105 million of 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 the agreement, the Company, severally with another major multinational company, may be required to fund more than their proportionate share of debt obligations of TransGas in the event that the minority shareholders fail to contribute. Any payments made by TransCanada under this agreement convert into share capital of TransGas. The potential exposure is contingent on the impact of any change of law on TransGas' ability to service the debt. From the issuance of the debt in 1995 to date, there has been no change in applicable law and thus no exposure to TransCanada. The debt matures in 2010 and the Company has made no provision related to this guarantee.

In connection with the acquisition of GTN in 2004, US$241 million of the purchase price was deposited into an escrow account. As at December 31, 2006, there was US$24 million remaining in the escrow account, which represented the full face amount of the potential liability under certain GTN guarantees. In February 2007, the funds were released and a portion of the monies were used to satisfy the liability of GTN under these designated guarantees.

Contingencies

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

The Company and its subsidiaries are subject to various other 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.

FINANCIAL AND OTHER INSTRUMENTS

The Company issues short-term and long-term debt, purchases and sells energy commodities, including amounts in foreign currencies, and invests in foreign operations. These activities result in exposures to interest rates, energy commodity prices and foreign currency exchange rates. The Company uses derivatives to manage the exposure that results from these activities. The use of derivatives is subject to the Company's overall risk management policies and procedures.

Derivatives and other instruments must be designated and be effective to qualify for hedge accounting. Derivatives are recorded at their fair value at each balance sheet date. For cash flow and fair value hedges, gains or losses relating to derivatives are deferred and recognized in the same period and in the same financial statement category as the corresponding hedged transactions. For hedges of net investments in self-sustaining foreign operations, exchange gains or losses on derivatives, after tax, and designated foreign currency denominated debt are offset against the exchange gains or losses arising on the translation of the financial statements of the foreign operations included in the foreign exchange adjustment account in Shareholders' Equity. In the event that a derivative does not meet the designation or effectiveness criteria, realized and unrealized gains or losses are recognized in income each period in the same financial statement category as the underlying transaction. Premiums paid or received with respect to derivatives that are hedges are deferred and amortized to income over the term of the hedge.

If a derivative that previously qualified as a hedge is settled, de-designated or ceases to be effective, the gain or loss at that date is deferred and recognized in the same period and in the same financial statement category as the corresponding hedged transactions. If a hedged anticipated transaction is no longer likely to occur, related deferred gains or losses are recognized in income in the current period.

The recognition of gains and losses on the derivatives for the Canadian Mainline, Alberta System, Foothills and the BC System exposures is determined through the regulatory process. The gains and losses on derivatives accounted for as part of rate-regulated accounting that do not meet the criteria for hedge accounting are deferred.

The fair value of foreign exchange and interest rate derivatives has been calculated using year-end market rates. The fair value of power, natural gas and heat rate derivatives has been calculated using estimated forward prices for the relevant period.

Net Investment in Foreign Operations
At December 31, 2006 and 2005, the Company had net investments in self-sustaining foreign operations with a U.S. dollar functional currency which created an exposure to changes in exchange rates. The Company uses U.S. dollar denominated debt and derivatives to hedge this exposure on an after-tax basis. The fair value for derivatives used to manage the exposure is shown in the table below.

Asset/(Liability)

		2006		2005	
December 31 (millions of dollars)	Accounting Treatment	**Fair Value**	**Notional or Principal Amount**	Fair Value	Notional or Principal Amount
US dollar cross-currency swaps (maturing 2007 to 2013)	Hedge	**58**	**U.S. 400**	119	U.S. 450
US dollar forward foreign exchange contracts (maturing 2007)	Hedge	**(7)**	**U.S. 390**	5	U.S. 525
US dollar options (maturing 2007)	Hedge	**(6)**	**U.S. 500**	–	U.S. 60

Reconciliation of Foreign Exchange Adjustment

December 31 (millions of dollars)	**2006**	2005
Balance at January 1 (loss)	**(90)**	(71)
Translation gains/(losses) on foreign currency denominated net assets[1]	**8**	(21)
(Losses)/gains on derivatives	**(9)**	23
Income taxes	**1**	(21)
Balance at December 31 (loss)	**(90)**	(90)

[1] The amount for 2006 includes gains of $6 million (2005 – $80 million) related to foreign currency denominated debt designated as a hedge.

Foreign Exchange and Interest Rate Management Activity

The Company manages the foreign exchange and interest rate risks related to its U.S. dollar denominated debt and transactions and interest rate exposures of the Canadian Mainline, the Alberta System and the BC System through the use of foreign currency and interest rate derivatives. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms. The details of the foreign exchange and interest rate derivatives are shown in the table below.

Asset/(Liability)

December 31 (millions of dollars)	Accounting Treatment	**2006** Fair Value	**2006** Notional or Principal Amount	2005 Fair Value	2005 Notional or Principal Amount
Foreign Exchange					
Cross-currency and interest-rate swaps					
(maturing 2013)	Hedge	**(32)**	**136/U.S. 100**	–	
(maturing 2010 to 2012)	Non-hedge	**(52)**	**227/U.S. 157**	(86)	363/U.S. 257
		(84)		(86)	
Interest Rate					
Interest rate swaps					
Canadian dollars					
(maturing 2007 to 2008)	Hedge	**2**	**100**	4	100
(maturing 2007 to 2009)	Non-hedge	**5**	**300**	7	374
		7		11	
US dollars					
(maturing 2007 to 2009)	Non-hedge	**4**	**U.S. 100**	5	U.S. 100

The Company manages the foreign exchange and interest rate exposures of its other businesses through the use of foreign currency and interest rate derivatives. The details of these foreign currency and interest rate derivatives are shown in the table below.

Asset/(Liability)

December 31 (millions of dollars)	Accounting Treatment	**2006** Fair Value	**2006** Notional or Principal Amount	2005 Fair Value	2005 Notional or Principal Amount
Foreign Exchange					
Options (maturing 2007)	Non-hedge	**–**	**U.S. 95**	1	U.S. 195
Forward foreign exchange contracts	Hedge	**–**	**–**	2	U.S. 29
(maturing 2007)	Non-hedge	**(3)**	**U.S. 250**	1	U.S. 208
		(3)		4	
Interest Rate					
Options (maturing 2007)	Non-hedge	**–**	**U.S. 50**	–	–
Interest rate swaps					
Canadian dollar					
(maturing 2007 to 2011)	Hedge	**–**	**150**	1	100
(maturing 2009 to 2011)	Non-hedge	**–**	**164**	1	423
		–		2	
US dollar					
(maturing 2011 to 2017)	Hedge	**(2)**	**U.S. 350**	–	U.S. 50
(maturing 2007 to 2016)	Non-hedge	**9**	**U.S. 450**	18	U.S. 550
		7		18	

For the year ended December 31, 2006, the Company had net losses of $1 million (2005 – net gains of $10 million; 2004 – net gains of $5 million) associated with interest rate swaps, which included a $6-million loss (2005 – $5-million loss; 2004 – $7-million gain) relating to a change in mark-to-market positions on non-hedges. The net losses are included in Financial Charges on the Consolidated Income Statement.

Foreign exchange gains included in Other Expenses/(Income) for the year ended December 31, 2006 are $4 million (2005 – $19 million; 2004 – $6 million).

Certain of the Company's joint ventures use interest rate derivatives to manage interest rate exposures. The Company's proportionate share of the fair value of the outstanding derivatives at December 31, 2006 and 2005 was nil.

Energy Price Risk Management

The Company executes power, natural gas and heat rate derivatives for overall management of its asset portfolio. Heat rate contracts are contracts for the sale or purchase of power that are priced based on a natural gas index. The fair value and notional volumes of contracts for differences and the swap, future, option and heat rate contracts are shown in the tables below.

Energy

Asset/(Liability)

December 31 (millions of dollars)	Accounting Treatment	**2006 Fair Value**	2005 Fair Value
Power – swaps and contracts for differences			
(maturing 2007 to 2011)	Hedge	**(179)**	(130)
(maturing 2007 to 2010)	Non-hedge	**(7)**	13
Gas – swaps, futures and options			
(maturing 2007 to 2016)	Hedge	**(66)**	17
(maturing 2007 to 2008)	Non-hedge	**30**	(11)
Heat rate contracts	Non-hedge	**–**	–

Notional Volumes

	Accounting	**Power (GWh)**		**Gas (Bcf)**	
December 31, 2006	Treatment	**Purchases**	**Sales**	**Purchases**	**Sales**
Power – swaps and contracts for differences					
(maturing 2007 to 2011)	Hedge	**6,654**	**12,349**	**–**	**–**
(maturing 2007 to 2010)	Non-hedge	**1,402**	**964**	**–**	**–**
Gas – swaps, futures and options					
(maturing 2007 to 2016)	Hedge	**–**	**–**	**77**	**59**
(maturing 2007 to 2008)	Non-hedge	**–**	**–**	**11**	**15**
Heat rate contracts	Non-hedge	**–**	**9**	**–**	**–**
December 31, 2005					
Power – swaps and contracts for differences	Hedge	2,566	7,780	–	–
	Non-hedge	1,332	456	–	–
Gas – swaps, futures and options	Hedge	–	–	91	69
	Non-hedge	–	–	15	18
Heat rate contracts	Non-hedge	–	35	–	–

During 2006, the Company recorded net gains of $41 million (2005 – net losses of $12 million; 2004 – net losses of $1 million) as a result of the non-hedge gas swaps, futures and options. These net gains were partially offset by losses from the non-hedge power swaps and contracts of $19 million (2005 – net gains of $16 million; 2004 – net losses of $3 million). The net impact of gains and losses on non-hedge derivatives for power, gas, and heat rate contracts were net gains of $22 million (2005 – net gains of $4 million; 2004 – net losses of $4 million) for the year included in Revenue.

At December 31, 2006, the Company had unrealized net losses of $222 million (2005 – net losses of $111 million) as a result of its energy swaps, futures, options and contracts that had not settled by year end. There were unrealized losses from unsettled energy derivatives of $144 million (2005 – $107 million) included in Accounts Payable and $158 million (2005 – $105 million) included in Deferred Amounts. These losses were partially offset by unrealized gains of $39 million (2005 – $44 million) included in Other Assets and $41 million (2005 – $57 million) included in Other Current Assets.

Certain of the Company's joint ventures use power derivatives to manage energy price risk exposures. The Company's proportionate share of the fair value of these outstanding power sales derivatives at December 31, 2006 was $55 million (2005 – $(38) million) and related to contracts which cover the period 2007 to 2010. The Company's proportionate share of the notional sales volumes associated with this exposure at December 31, 2006 was 4,500 GWh (2005 – 2,058 GWh).

RISKS AND RISK MANAGEMENT

Risk Management Overview

TransCanada and its subsidiaries are exposed to market, financial and counterparty risks in the normal course of their business activities. The risk management function assists in managing these various business activities and the risks associated with them. A strong commitment to a risk management culture by TransCanada's Management supports this function. TransCanada's primary risk management objective is to protect earnings and cash flow and ultimately, shareholder value.

The risk management function is guided by the following principles that are applied to all businesses and risk types:

- *Board Oversight* – Risk strategies, policies and limits are subject to review and approval by TransCanada's Board of Directors.
- *Independent Review* – Risk-taking activities are subject to independent review, separate from the business lines that initiate the activity.
- *Assessment* – Processes are in place to ensure that risks are properly assessed at the transaction and counterparty levels.
- *Review and Reporting* – Market positions and exposures, and the creditworthiness of counterparties are subject to ongoing review and reporting to executive management.
- *Accountability* – Business lines are accountable for all risks and the related returns for their particular businesses.
- *Audit Review* – Individual risks are subject to internal audit review, with independent reporting to the Audit Committee of TransCanada's Board of Directors.

The processes within TransCanada's risk management function are designed to ensure that risks are properly identified, quantified, reported and managed. Risk management strategies, policies and limits are designed to ensure TransCanada's risk-taking is consistent with the Company's business objectives and risk tolerance. Risks are managed within limits ultimately established by the Company's Board of Directors and implemented by senior management, monitored by risk management personnel and audited by internal audit personnel.

TransCanada manages market, financial and counterparty risks and related exposures in accordance with the Company's market risk, interest rate and foreign exchange risk and counterparty risk policies. The Company's primary market and financial risks result from volatility in commodity prices, interest rates and foreign currency exchange rates.

Senior management reviews these exposures and reports on a regular basis to the Audit Committee of TransCanada's Board of Directors.

Market Risk Management
In order to manage market risk exposures created by fixed and variable pricing arrangements at different pricing indices and delivery points, the Company enters into offsetting physical positions and derivative financial instruments. Market risks are quantified using value-at-risk methodology and are reviewed weekly by senior management.

Financial Risk Management
TransCanada monitors the financial market risk exposures relating to the Company's investments in foreign currency denominated net assets, regulated and non-regulated long-term debt portfolios and foreign currency exposure on transactions. The market risk exposures created by these business activities are managed by establishing offsetting positions or through the use of derivative financial instruments.

Counterparty Risk Management
Counterparty risk is the financial loss that the Company would experience if the counterparty failed to meet its obligations in accordance with the terms and conditions of its contracts with the Company. Counterparty risk is mitigated by conducting financial and other assessments to establish a counterparty's creditworthiness, setting exposure limits and monitoring exposures against these limits, and, where warranted, obtaining financial assurances.

The Company's counterparty risk management practices and positions are further described in Note 15 to the consolidated financial statements.

Development Projects and Acquisitions
TransCanada continues to focus on growing its Pipelines and Energy operations through greenfield projects and acquisitions. TransCanada defers costs incurred on certain of its development projects during the period prior to construction when the project meets specific criteria including an expectation that the project will proceed to ultimate completion. If an individual project does not proceed, the related deferred costs would be expensed at that time. With respect to TransCanada's acquisition of existing assets and operations, there is a risk that certain commercial opportunities and operational synergies may not materialize as originally expected.

Foreign Exchange
A portion of TransCanada's earnings from its Pipelines and Energy operations in the U.S. are generated in U.S. dollars and are subject to currency fluctuations. The performance of the Canadian dollar relative to the U.S. dollar could either positively or negatively impact TransCanada's net earnings, although much of this foreign exchange impact is offset by exposures in certain of TransCanada's businesses as well as through the Company's hedging activities. With the acquisition of ANR and a greater ownership interest in PipeLines LP, TransCanada expects to have a greater exposure to U.S. dollar fluctuations.

Risks and Risk Management Related to Environmental Regulations
Climate change remains a serious issue for TransCanada. The change of government in Canada in early 2006 resulted in a shift of focus from meeting greenhouse gas reduction targets to a broader emphasis on clean air as well as greenhouse gas emissions. The Government of Canada released the *Clean Air Act* on October 19, 2006. At this time, however, the policy framework for the new regulations has not been released by the federal government and detailed sectoral targets and timeframes as well as compliance options have not been set. At a provincial level, the Québec government has passed legislation for a hydrocarbon royalty on industrial greenhouse gas emitters. The details as to how the royalty will be applied have not yet been determined but it is expected these details will be set in the coming year. In Alberta, the government has indicated it will continue with its own plan for implementing regulations to manage greenhouse gas emissions. It is yet to be determined how this effort will tie into a federal program.

In the U.S., state level initiatives are under way to limit greenhouse gas emissions, particularly in the northeastern U.S. and California. Details have not been finalized and the impact to TransCanada's U.S.-based assets is uncertain.

Despite this uncertainty, TransCanada continues with its programs to manage greenhouse gas emissions from its assets, and to evaluate new processes and technologies that result in improved efficiencies and lower greenhouse gas emissions rates. In addition, TransCanada remains involved in policy discussions in those jurisdictions where policy development is under way and where the Company has operations.

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 of December 31, 2006, an evaluation was carried out, under the supervision of and with the participation of management, including the President and Chief Executive Officer and Chief Financial Officer, of the effectiveness of TransCanada's disclosure controls and procedures as defined under the rules adopted by the Canadian securities regulatory authorities and by the U.S. Securities and Exchange Commission (SEC). Based on that evaluation, the President and Chief Executive Officer and Chief Financial Officer concluded that the design and operation of TransCanada's disclosure controls and procedures were effective as at December 31, 2006.

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 of, and with the participation of, management, including the President and Chief Executive Officer and Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, according to these criteria, management concluded that internal control over financial reporting is effective as of December 31, 2006 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

During the year ended December 31, 2006, there has been no change in TransCanada's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, TransCanada's internal control over financial reporting.

CEO and CFO Certifications

With respect to the year ending December 31, 2006, TransCanada's President and Chief Executive Officer has provided the New York Stock Exchange with the annual CEO certification regarding TransCanada's compliance with the New York Stock Exchange's corporate governance listing standards applicable to foreign issuers. In addition, TransCanada's President and Chief Executive Officer and Chief Financial Officer have filed with the SEC and the Canadian securities regulators certifications regarding the quality of TransCanada's public disclosures relating to its fiscal 2006 reports filed with the SEC and the Canadian securities regulators.

Compliance Expenditures

The total cost incurred by TransCanada to comply with the requirements of the SEC and Canadian securities regulatory authorities arising out of the *Sarbanes-Oxley Act of 2002* for the period January 1, 2002 to December 31, 2006, was estimated to be $14 million, including third party charges of $4 million.

SIGNIFICANT ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

Since determining the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of the Company's consolidated financial statements requires the use of estimates and assumptions which have been made using careful judgment.

Regulated Accounting

The Company accounts for the impacts of rate regulation in accordance with GAAP as outlined in Notes 1 and 11 to the consolidated financial statements. Three criteria must be met to use these accounting principles: the rates for regulated services or activities must be subject to approval by a regulator; the regulated rates must be designed to recover the cost of providing the services or products; and it must be reasonable to assume that rates set at levels to recover the cost can be charged to and will be collected from customers in view of the demand for services or products and the level of direct and indirect competition. The Company's management believes that all three of these criteria have been met. The most significant impact from the use of these accounting principles is that, in order to appropriately reflect the economic impact of the regulators' decisions regarding the Company's revenues and tolls, and to thereby achieve a proper matching of revenues and expenses, the timing of recognition of certain expenses and revenues in the regulated businesses may differ from that otherwise expected under GAAP as detailed in Note 11 to the consolidated financial statements.

Derivative Accounting

The Company enters into the following financial instruments to manage its risk exposure:

- power, natural gas and heat rate derivatives for overall management of its commodity price exposure;
- foreign currency and interest rate derivatives to manage its foreign exchange and interest rate risks related to its U.S. dollar denominated debt and transactions and interest rate exposures; and
- U.S. dollar denominated debt and U.S. dollar swaps, forwards and options to hedge the exposure on an after-tax basis of net investments in self sustaining foreign operations with a U.S. dollar functional currency.

Derivatives are recorded at their fair value at each balance sheet date. Derivatives and other instruments must be designated and be effective to qualify for hedge accounting. For cash flow and fair value hedges, gains or losses relating to derivatives are deferred and recognized in the same period and in the same financial statement category as the corresponding hedged transactions. Unrealized long-term gains and losses are included in Other Assets and Deferred Amounts, respectively. Unrealized current gains and losses are included in Other Current Assets and Accounts Payable, respectively. For hedges of net investments in self-sustaining foreign operations, exchange gains or losses on derivatives, after tax, and designated foreign currency denominated debt are offset against the exchange losses or gains arising on the translation of the financial statements of the foreign operations included in the foreign exchange adjustment account in Shareholders' Equity.

Assessment of effectiveness for those derivatives classified as hedges occurs at inception and on an ongoing basis. The determination of whether a derivative contract qualifies as a cash flow hedge includes an analysis of historical market price information to assess whether the derivatives are expected to be highly effective in achieving offsetting cash flows attributable to the hedged risk. In the event that a derivative does not meet the designation or effectiveness criteria, realized and unrealized gains or losses are recognized in income each period in the same financial category as the underlying transaction giving rise to the exposure being economically hedged. If an anticipated transaction is hedged and the transaction is no longer probable to occur, the related deferred gains or losses are recognized in income in the current period.

The recognition of gains and losses on derivatives for the Canadian Mainline, Alberta System, Foothills and the BC System exposures is determined through the regulatory process. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms. The gains and losses on derivatives accounted for as part of rate-regulated accounting that do not meet the criteria for hedge accounting are deferred.

The fair value for derivative contracts is determined based on the nature of the transactions and the market in which transactions are executed. Assumptions and judgements about counterparty performance and credit considerations are incorporated in the determination of fair value.

The Company estimates the fair value of derivative contracts by using readily available price quotes in similar markets and other market analyses. The number of transactions executed without quoted market prices is limited. The fair value of all derivative contracts is continually subject to change as the underlying commodity market changes and TransCanada's assumptions and judgments change. The fair value of foreign exchange and interest rate derivatives has been calculated using year end market rates. The fair value of power, natural gas and heat rate derivatives is calculated using estimated forward prices for the relevant period.

The chart below shows the effect that a one dollar change in the price of power (per MWh) or gas (per GJ) would have on the calculation of the fair values of derivatives as recorded on the balance sheet.

	Increase $1	Decrease $1
(millions of dollars)	Effect on fair value	Effect on fair value
Western Power Operations – power	−8	+8
Eastern Power Operations – power	+2	−3
Eastern Power Operations – gas	+19	−19

Depreciation and Amortization Expense

TransCanada's plant, property and equipment are depreciated on a straight-line basis over their estimated useful lives. Pipeline and compression equipment are depreciated at annual rates from two to six per cent. Major power generation and natural gas storage plant, equipment and structures in the Energy business are depreciated at average annual rates ranging from two to ten per cent. Nuclear power generation assets under capital lease are amortized over the shorter of their useful life or the remaining terms of their lease. Other equipment is depreciated at various rates.

Depreciation expense for the year ended December 31, 2006 was $1,059 million and primarily impacts the Pipelines and Energy segments of the Company. In Pipelines, depreciation rates are approved by the regulators, where applicable, and depreciation expense is recoverable based on the cost of providing the services or products. A change in the estimation of the useful lives of the plant, property and equipment in the Pipelines segment would, if recovery through rates is permitted by the regulators, have no material impact on TransCanada's net income but would directly impact funds generated from operations.

ACCOUNTING CHANGES

Non-Monetary Transactions

Effective for non-monetary transactions initiated in periods beginning on or after January 1, 2006, the new Handbook Section 3831 "Non-Monetary Transactions" requires all non-monetary transactions to be measured at fair value, subject to certain exceptions. Commercial substance replaces culmination of the earnings process as the test for fair value measurement and is a function of the cash flows expected from the exchanged assets. Adopting the provisions of this standard in 2006 did not have an impact on the Company's consolidated financial statements.

Financial Instruments – Recognition and Measurement

Effective for interim and annual financial statements beginning on or after October 1, 2006, the new Handbook Section 3855 "Financial Instruments – Recognition and Measurement" prescribes that all financial instruments within the scope of this standard, including derivatives, be included on a company's balance sheet. Contracts that can be settled by receipt or delivery of a commodity will also be included in the scope of the section. These financial instruments must be measured, either at their fair value or, in limited circumstances when fair value may not be considered the most relevant measurement method, at cost or amortized cost. It also specifies when gains and losses as a result of changes in fair value are to be recognized in the income statement. This new Handbook section will be adopted by the Company as of January 1, 2007 on a prospective basis. TransCanada does not expect this new requirement to have a significant impact on the Company's consolidated financial statements.

Hedges

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2006, the new Handbook Section 3865 "Hedges" specifies the circumstances under which hedge accounting is permissible, how hedge accounting may be performed, and where the impacts should be recorded. The provisions of this standard introduce three specific types of hedging relationships: fair value hedges, cash flow hedges and hedges of a net investment in self-sustaining foreign operations. This new Handbook section will be adopted by the Company as of January 1, 2007 on a prospective basis. TransCanada does not expect this new requirement to have a significant impact on the Company's consolidated financial statements.

Comprehensive Income

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2006, the new Handbook Section 1530 "Comprehensive Income" requires that an enterprise present comprehensive income and its components in a separate financial statement that is displayed with the same prominence as other financial statements. This Section introduces a new requirement to present certain gains and losses temporarily outside net income. This Handbook section will be adopted by the Company as of January 1, 2007 on a prospective basis. Beginning first quarter 2007, TransCanada's financial statements will include a Statement of Comprehensive Income and a Statement of Accumulated Comprehensive Income.

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA[1]

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

	2005			
(millions of dollars except per share amounts)	Fourth	Third	Second	First
Revenues	1,771	1,494	1,449	1,410
Net Income				
Continuing operations	350	427	200	232
Discontinued operations	–	–	–	–
	350	427	200	232
Share Statistics				
Net income per share – Basic				
Continuing operations	$0.72	$0.88	$0.41	$0.48
Discontinued operations	–	–	–	–
	$0.72	$0.88	$0.41	$0.48
Net income per share – Diluted				
Continuing operations	$0.71	$0.87	$0.41	$0.48
Discontinued operations	–	–	–	–
	$0.71	$0.87	$0.41	$0.48
Dividend declared per common share	$0.305	$0.305	$0.305	$0.305

[1] The selected quarterly consolidated financial data has been prepared in accordance with Canadian GAAP. Certain comparative figures have been reclassified to conform with the current year's presentation. For a discussion on the factors affecting the comparability of the financial data, including discontinued operations, refer to Notes 1 and 22 of TransCanada's 2006 audited consolidated financial statements included in TransCanada's 2006 Annual Report.

Factors Impacting Quarterly Financial Information

In Pipelines, which consists primarily of the Company's investments in regulated pipelines, 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 arising as a result of adjustments being recorded due to regulatory decisions and negotiated settlements with shippers, seasonal fluctuations in short-term throughput volumes on U.S. pipelines and items outside of the normal course of operations.

In Energy, which consists primarily of the Company's investments in electrical power generation plants and 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 as well as items outside of the normal course of operations.

Significant items which impacted 2006 and 2005 quarterly net earnings are as follows.

- In first quarter 2005, net earnings included a $48-million after-tax gain related to the sale of PipeLines LP units. Energy earnings included a $10-million after-tax cost for the restructuring of natural gas supply contracts by OSP. In addition, Bruce Power's equity income was lower than previous quarters due to the impact of planned maintenance outages and the increase in operating costs as a result of moving to a six-unit operation.
- Second quarter 2005 net earnings included $21 million ($13 million related to 2004 and $8 million related to 2005) with respect to the NEB's decision on the Canadian Mainline's 2004 Tolls and Tariff Application (Phase II). On April 1, 2005, TransCanada completed the acquisition of hydroelectric generation assets from USGen. Bruce Power's income from equity investments was lower than previous quarters due to the continuing impact of planned maintenance outages and an unplanned maintenance outage on Unit 6 relating to a transformer fire.
- In third quarter 2005, net earnings included a $193-million after-tax gain related to the sale of the Company's ownership interest in Power LP. In addition, Bruce Power's income from equity investments increased from prior quarters due to higher realized power prices and slightly higher generation volumes.
- In fourth quarter 2005, net earnings included a $115-million after-tax gain on the sale of Paiton Energy. In addition, Bruce A was formed and Bruce Power's results were proportionately consolidated, effective October 31, 2005.
- In first quarter 2006, net earnings included an $18-million after tax ($29-million pre-tax) bankruptcy settlement from a former shipper on the Gas Transmission Northwest System.
- In second quarter 2006, net earnings included $33 million of future income tax benefits as a result of reductions in Canadian federal and provincial corporate income tax rates. Net earnings also included a $13-million after-tax gain related to the sale of the Company's interest in Northern Border Partners, L.P.
- In third quarter 2006, net earnings included an income tax benefit of approximately $50 million as a result of the resolution of certain income tax matters with taxation authorities and changes in estimates.
- In fourth quarter 2006, net earnings included approximately $12 million related to income tax refunds and related interest.

FOURTH QUARTER 2006 HIGHLIGHTS

SEGMENT RESULTS-AT-A-GLANCE
Three months ended December 31

(millions of dollars except per share amounts)	**2006**	2005
Pipelines	**126**	155
Energy		
Excluding gains	**132**	87
Gain on sale of Paiton Energy	**–**	115
	132	202
Corporate	**11**	(7)
Net Income(1)	**269**	350
Net Income Per Share – Basic(2)	**$0.55**	$0.72

(1)**Net Income**		
Excluding gain	**269**	235
Gain on sale of Paiton Energy	**–**	115
	269	350
(2)**Net Income Per Share – Basic**		
Excluding gain	**$0.55**	$0.48
Gain on sale of Paiton Energy	**–**	0.24
	$0.55	$0.72

Net income for fourth quarter 2006 of $269 million, or $0.55 per share, decreased by $81 million or $0.17 per share compared to $350 million or $0.72 per share for fourth quarter 2005. This decrease was primarily due to an after-tax gain of $115 million or $0.24 per share from the sale of Paiton Energy in fourth quarter 2005.

Excluding the $115-million gain related to the sale of Paiton Energy, net income for fourth quarter 2006 increased $34 million, or $0.07 per share, compared to fourth quarter 2005. This was primarily due to increases of $45 million and $18 million in net earnings from Energy and Corporate, respectively, partially offset by a decrease of $29 million in net earnings from the Pipelines business.

For fourth quarter 2006, Pipeline's net income decreased $29 million compared to fourth quarter 2005 due to a $22-million reduction in net earnings from Wholly Owned Pipelines and a $7-million decrease in net earnings from the Other Pipelines businesses. Wholly Owned Pipelines' net earnings decreased primarily due to a lower ROE and lower average investment bases in the Canadian Mainline and the Alberta System. Net earnings from GTN decreased due to increased operating costs and lower transportation revenues. Net earnings for TransCanada's Other Pipelines decreased primarily due to higher project development and support costs and the impact of a weaker U.S. dollar.

Excluding the gain of $115 million in 2005, Energy's net earnings increased $45 million in fourth quarter 2006, compared to fourth quarter 2005, due to higher operating income from Western Power Operations, Natural Gas Storage and Bruce Power. Partially offsetting these increases were lower operating income from Eastern Power Operations and higher general, administrative and support costs.

Bruce Power's contribution to operating income increased $6 million in fourth quarter 2006, compared to fourth quarter 2005, primarily due to an increased ownership interest in the Bruce A facilities and the positive impact of higher generation volumes, partially offset by lower overall realized prices and higher operating expenses.

Western Power Operations' operating income was $76 million higher in fourth quarter 2006, compared to fourth quarter 2005, primarily due to incremental earnings from the December 31, 2005 acquisition of the 756 MW Sheerness PPA and increased margins from a combination of higher overall realized power prices and higher market heat rates on sales of uncontracted power volumes.

Eastern Power Operations' operating income was $13 million lower in fourth quarter 2006, compared to fourth quarter 2005, primarily due to record hurricane activity in the Gulf of Mexico in 2005 which caused a significant increase in certain commodity prices and increased hydro generation volumes. As a result, higher profits were earned in 2005 from increased generation volumes as a result of unusually high water flows through the TC Hydro facilities, increased margins on the natural gas purchased and resold under the OSP gas supply contracts and higher prices realized on power sold into the spot market. The quarter-over-quarter decrease was partially offset by incremental income earned in 2006 from the startup of the 550 MW Bécancour cogeneration plant in September 2006 and the first wind farm of the Cartier Wind project in November 2006.

Natural Gas Storage operating income increased $13 million in fourth quarter 2006, compared to fourth quarter 2005, primarily due to higher contributions from CrossAlta as a result of increased storage capacity and higher natural gas storage spreads.

General, administrative, support costs and other of the Energy business increased $8 million in fourth quarter 2006, compared to fourth quarter 2005, primarily due to higher business development costs associated with growing the Energy business.

Corporate's net earnings increased $18 million to $11 million in fourth quarter 2006 primarily due to income tax refunds and related interest of approximately $12 million and other positive income tax adjustments.

SHARE INFORMATION

At February 22, 2007, TransCanada had 528.7 million issued and outstanding common shares. In addition, there were 9.6 million outstanding options to purchase common shares, of which 5.6 million were exercisable as at February 22, 2007.

In February 2007, the Company issued 39,470,000 subscription receipts. These subscription receipts were exchanged on a one-for-one basis for common shares upon the closing of the ANR acquisition. In addition, TransCanada granted the underwriters of the subscription receipts offering an option to purchase an additional 5,920,500 common shares at $38.00 per common share at any time up to and including March 16, 2007.

OTHER INFORMATION

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

Other selected consolidated financial information for the years ended December 31, 2006, 2005, 2004, 2003, 2002, 2001 and 2000 is found under the heading "Seven-Year Financial Highlights" on pages 121 and 122 of this Annual Report.

GLOSSARY OF TERMS

ACES	Accelerated Clean Energy Supply
ANR	The American Natural Resources Company and the ANR Storage Company, collectively
APG	Aboriginal Pipeline Group
B.C.	British Columbia
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
BPC	BPC Generation Infrastructure Trust
Broadwater	Broadwater Energy project
Bruce A	Bruce Power A L.P.
Bruce B	Bruce Power L.P.
Bruce Power	The collective investments in Bruce A and Bruce B
Cacouna	Cacouna Energy project
Calpine	Calpine Corporation and certain of its subsidiaries
Cameco	Cameco Corporation
CAPLA	Canadian Alliance of Pipeline Landowners' Associations
CAPP	Canadian Association of Petroleum Producers
CPPL	ConocoPhillips Pipe Line Company
CrossAlta	CrossAlta Gas Storage & Services Ltd.
DBRS	Dominion Bond Rating Service Limited
DRP	Dividend Reinvestment and Share Purchase Plan
EPCOR	EPCOR Utilities Inc.
EUB	Alberta Energy and Utilities Board
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
Foothills	Foothills Pipe Lines Ltd.
FT	Firm transportation
GAAP	Generally accepted accounting principles
Gas Pacifico	Gasoducto del Pacifico S.A.
GJ	Gigajoule
GRA	General Rate Application
Great Lakes	Great Lakes Gas Transmission Limited Partnership
GTA	Greater Toronto Area
GTN	Gas Transmission Northwest System and the North Baja system, collectively
GTNC	Gas Transmission Northwest Corporation
GWh	Gigawatt hours
INNERGY	INNERGY Holdings S.A.
Iroquois	Iroquois Gas Transmission System, L.P.
JRP	Joint Review Panel
Keystone	TransCanada Keystone Pipeline GP Ltd.
km	Kilometres
LNG	Liquefied natural gas
MD&A	Management's Discussion and Analysis
MGP	Mackenzie Gas Pipeline
Millennium	Millennium Pipeline project
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 hour
NBV	Net book value
NEB	National Energy Board
Net earnings	Net income from continuing operations
NEPOOL	New England Power Pool
NGLs	Natural gas liquids
Northern Border	Northern Border Pipeline Company
NPA	Northern Pipeline Act of Canada
OM&A	Operating, maintenance and administration
OPA	Ontario Power Authority
OSP	Ocean State Power
Paiton Energy	P.T. Paiton Energy Company
PG&E	Pacific Gas & Electric Company
PipeLines LP	TC PipeLines, LP
Portland	Portland Natural Gas Transmission System
Portlands Energy	Portlands Energy Centre L.P.
Power LP	TransCanada Power, L.P.
PPA	Power purchase arrangement
ROE	Rate of return on common equity
S&P	Standard & Poor's
SEC	U.S. Securities and Exchange Commission
Shell	Shell US Gas & Power LLC
TBO	Transportation by Others
TCPL	TransCanada PipeLines Limited
TCPM	TransCanada Power Marketing Ltd.
TQM	Trans Québec & Maritimes System
TransCanada or the Company	TransCanada Corporation
TransGas	TransGas de Occidente S.A.
Tuscarora	Tuscarora Gas Transmission Company
U.S.	United States
USGen	USGen New England, Inc.
Ventures LP	TransCanada Pipeline Ventures Limited Partnership
WCSB	Western Canada Sedimentary Basin

Report of Management

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

Management has prepared Management's Discussion and Analysis which is based on the Company's financial results prepared in accordance with Canadian GAAP. It compares the Company's financial performance in 2006 to 2005 and should be read in conjunction with the consolidated financial statements and accompanying notes. In addition, significant changes between 2005 and 2004 are highlighted.

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

Under the supervision and with the participation of the President and Chief Executive Officer and Chief Financial Officer, Management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment according to these criteria, Management concluded that internal control over financial reporting is effective as of December 31, 2006 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

The Board of Directors has appointed an Audit Committee consisting of unrelated, non-management directors which meets at least five times during the year with Management and independently with each of the internal and external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the charter of the Audit Committee as set out in the Annual Information Form. The Audit Committee reviews the Annual Report, including the consolidated financial statements, before the consolidated financial statements are submitted to the Board of Directors for approval. The internal and external auditors have free access to the Audit Committee without obtaining prior Management approval.

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

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

Harold N. Kvisle
President and
Chief Executive Officer

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

February 22, 2007

Auditors' Report

To the Shareholders of TransCanada Corporation

We have audited the consolidated balance sheets of TransCanada Corporation as at December 31, 2006 and 2005 and the consolidated statements of income, retained earnings and cash flows for each of the years in the three-year period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. With respect to the consolidated financial statements for the years ended December 31, 2006 and 2005, we also conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2006 and 2005 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2006 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada

February 22, 2007

TRANSCANADA CORPORATION
CONSOLIDATED INCOME

Year ended December 31 *(millions of dollars except per share amounts)*	**2006**	2005	2004
Revenues	**7,520**	6,124	5,497
Operating Expenses			
Plant operating costs and other	**2,411**	1,825	1,615
Commodity purchases resold	**1,707**	1,232	940
Depreciation	**1,059**	1,017	948
	5,177	4,074	3,503
	2,343	2,050	1,994
Other Expenses/(Income)			
Financial charges (Note 8)	**825**	836	858
Financial charges of joint ventures (Note 9)	**92**	66	63
Income from equity investments (Note 6)	**(33)**	(247)	(213)
Interest income and other	**(123)**	(63)	(59)
Gains on sale of assets (Note 7)	**(23)**	(445)	(204)
	738	147	445
Income from Continuing Operations before Income Taxes and Non-Controlling Interests	**1,605**	1,903	1,549
Income Taxes (Note 16)			
Current	**301**	550	414
Future	**175**	60	77
	476	610	491
Non-Controlling Interests (Note 13)	**78**	84	78
Net Income from Continuing Operations	**1,051**	1,209	980
Net Income from Discontinued Operations (Note 22)	**28**	–	52
Net Income	**1,079**	1,209	1,032
Net Income Per Share (Note 14)			
Basic			
Continuing operations	**$2.15**	$2.49	$2.02
Discontinued operations	**0.06**	–	0.11
	$2.21	$2.49	$2.13
Diluted			
Continuing operations	**$2.14**	$2.47	$2.01
Discontinued operations	**0.06**	–	0.11
	$2.20	$2.47	$2.12

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

TRANSCANADA CORPORATION
CONSOLIDATED CASH FLOWS

Year ended December 31 *(millions of dollars)*	**2006**	2005	2004
Cash Generated from Operations			
Net income	**1,079**	1,209	1,032
Depreciation	**1,059**	1,017	948
Gains on sale of assets, net of current tax (Note 7)	**(11)**	(318)	(204)
Income from equity investments in excess of distributions received (Note 6)	**(9)**	(71)	(113)
Future income taxes (Note 16)	**175**	60	77
Non-controlling interests (Note 13)	**78**	84	78
Funding of employee future benefits in excess of expense (Note 19)	**(31)**	(9)	(29)
Other	**38**	(21)	(86)
	2,378	1,951	1,703
(Increase)/decrease in operating working capital (Note 20)	**(303)**	(49)	29
Net cash provided by operations	**2,075**	1,902	1,732
Investing Activities			
Capital expenditures	**(1,572)**	(754)	(530)
Acquisitions, net of cash acquired (Note 7)	**(470)**	(1,317)	(1,516)
Disposition of assets, net of current tax (Note 7)	**23**	671	410
Deferred amounts and other	**(97)**	64	(12)
Net cash used in investing activities	**(2,116)**	(1,336)	(1,648)
Financing Activities			
Dividends on common shares	**(617)**	(586)	(552)
Distributions paid to non-controlling interests	**(72)**	(74)	(87)
Notes payable (repaid)/issued, net	**(495)**	416	179
Long-term debt issued	**2,107**	799	1,090
Repayment of long-term debt	**(729)**	(1,113)	(1,005)
Long-term debt of joint ventures issued	**56**	38	217
Repayment of long-term debt of joint ventures	**(70)**	(80)	(112)
Common shares issued (Note 14)	**39**	44	32
Partnership units of joint ventures issued	**–**	–	88
Net cash provided by/(used in) financing activities	**219**	(556)	(150)
Effect of Foreign Exchange Rate Changes on Cash and Short-Term Investments	**9**	11	(87)
Increase/(Decrease) in Cash and Short-Term Investments	**187**	21	(153)
Cash and Short-Term Investments			
Beginning of year	**212**	191	344
Cash and Short-Term Investments			
End of year	**399**	212	191

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

TRANSCANADA CORPORATION
CONSOLIDATED BALANCE SHEET

December 31 *(millions of dollars)*	**2006**	2005
ASSETS		
Current Assets		
Cash and short-term investments	**399**	212
Accounts receivable	**1,004**	796
Inventories	**392**	281
Other	**297**	277
	2,092	1,566
Long-Term Investments (Note 6)	**71**	400
Plant, Property and Equipment (Note 3)	**21,487**	20,038
Goodwill	**281**	57
Other Assets (Note 4)	**1,978**	2,052
	25,909	24,113
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable (Note 17)	**467**	962
Accounts payable	**1,500**	1,494
Accrued interest	**264**	222
Current portion of long-term debt (Note 8)	**616**	393
Current portion of long-term debt of joint ventures (Note 9)	**142**	41
	2,989	3,112
Deferred Amounts (Note 10)	**1,029**	1,196
Future Income Taxes (Note 16)	**876**	703
Long-Term Debt (Note 8)	**10,887**	9,640
Long-Term Debt of Joint Ventures (Note 9)	**1,136**	937
Preferred Securities (Note 12)	**536**	536
	17,453	16,124
Non-Controlling Interests (Note 13)	**755**	783
Shareholders' Equity		
Common shares (Note 14)	**4,794**	4,755
Contributed surplus	**273**	272
Retained earnings	**2,724**	2,269
Foreign exchange adjustment (Note 15)	**(90)**	(90)
	7,701	7,206
Commitments, Contingencies and Guarantees (Note 21)		
Subsequent Events (Note 23)		
	25,909	24,113

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

On behalf of the Board:

Harold N. Kvisle
Director

Harry G. Schaefer
Director

TRANSCANADA CORPORATION
CONSOLIDATED RETAINED EARNINGS

Year ended December 31 *(millions of dollars)*	**2006**	2005	2004
Balance at beginning of year	**2,269**	1,655	1,185
Net income	**1,079**	1,209	1,032
Common share dividends	**(624)**	(595)	(562)
	2,724	2,269	1,655

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

TRANSCANADA CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

Pipelines
The Pipelines segment owns and operates the following natural gas pipelines:

- a natural gas transmission system extending from the Alberta border east into Québec (the Canadian Mainline);
- a natural gas transmission system in Alberta (the Alberta System);
- a natural gas transmission system extending from the British Columbia/Idaho border to the Oregon/California border, traversing Idaho, Washington and Oregon (the Gas Transmission Northwest 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 the Alberta border west into southeastern B.C. (the BC System);
- a natural gas transmission system extending from a point near Ehrenberg, Arizona to the Baja California, Mexico/California border (North Baja);
- natural gas transmission systems in Alberta, owned by TransCanada Pipeline Ventures Limited Partnership (Ventures LP), that supply natural gas to the oil sands region of northern Alberta and to a petrochemical complex at Joffre, Alberta;
- a natural gas transmission system in Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi (Tamazunchale);
- a 61.7 per cent interest in Portland Natural Gas Transmission System (Portland), which owns a pipeline system that extends from a point near East Hereford, Québec and delivers natural gas to the northeastern U.S.; and
- a 50 per cent interest in TQM Services Limited Partnership (TQM), which owns a pipeline system that connects with the Canadian Mainline and transports natural gas in Québec, from Montreal to Québec City, and to the Portland system.

Pipelines also holds the Company's investments in other natural gas pipelines primarily in North America. TransCanada's other significant pipeline investments include:

- a 50 per cent interest in Great Lakes Gas Transmission Limited Partnership (Great Lakes), which owns a natural gas pipeline system that connects to the Canadian Mainline and serves markets in Central Canada and Eastern and Midwestern U.S.; and
- a 44.5 per cent interest in Iroquois Gas Transmission System, L.P. (Iroquois), which owns a natural gas pipeline system that connects with the Canadian Mainline near Waddington, New York and delivers to customers in the northeastern U.S.

In addition, Pipelines investigates and develops new natural gas and crude oil pipelines in North America.

TransCanada is the general partner of and consolidates its 13.4 per cent (at December 31, 2006) interest in TC PipeLines, LP (PipeLines LP), which holds the following investments:

- a 50 per cent interest in Northern Border Pipeline Company (Northern Border), which owns a pipeline system that transports natural gas from a point near Monchy, Saskatchewan to the U.S. Midwest. TransCanada expects to begin operating Northern Border in April 2007. TransCanada's effective ownership in Northern Border is 6.7 per cent; and
- owns or controls a 99 per cent interest in Tuscarora Gas Transmission Company (Tuscarora), which owns a pipeline system that transports natural gas from Malin, Oregon to Wadsworth, Nevada. TransCanada became the operator of Tuscarora in December 2006. TransCanada effectively owns or controls 14.3 per cent of Tuscarora, including one per cent owned directly by TransCanada.

Energy
The Energy segment builds, owns and operates electrical power generation plants, and sells electricity. Energy also holds the Company's investments in other electrical power generation plants, natural gas storage facilities as well as the Company's interest in liquefied natural gas (LNG) regassification projects in North America. This business operates in Canada and the U.S. as follows:

TransCanada owns and operates:

- hydroelectric generation assets located in New Hampshire, Vermont and Massachusetts (TC Hydro);
- a natural gas-fired, combined-cycle plant in Burrillville, Rhode Island (Ocean State Power);
- natural gas-fired cogeneration plants in Alberta at Carseland, Redwater, Bear Creek and MacKay River;
- a natural gas-fired cogeneration plant near Saint John, New Brunswick (Grandview);

- a waste-heat fuelled power plant at the Cancarb facility in Medicine Hat, Alberta (Cancarb);
- a natural gas-fired cogeneration plant near Trois-Rivières, Québec (Bécancour); and
- a natural gas storage facility near Edson, Alberta (Edson).

TransCanada owns but does not operate:

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

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

- 100 per cent of the production of the Sundance A power facilities and 50 per cent, through a partnership, of the production of the Sundance B power facilities near Wabamun, Alberta; and
- 100 per cent of the production of the Sheerness power facility near Hanna, Alberta.

TransCanada has under construction:

- phase two of the six-phase Cartier Wind project in Québec, owned 62 per cent by TransCanada;
- a combined-cycle natural gas cogeneration plant in downtown Toronto, Ontario, owned 50 per cent by TransCanada (Portlands Energy); and
- a natural gas-fired, combined-cycle power plant near Toronto, Ontario (Halton Hills).

NOTE 1 ACCOUNTING POLICIES

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

Since a determination of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of these consolidated financial statements requires the use of estimates and assumptions which have been made using careful judgment. In the opinion of Management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized below.

Basis of Presentation

The consolidated financial statements include the accounts of TransCanada Corporation and its subsidiaries as well as its proportionate share of the accounts of its joint ventures. TransCanada uses the equity method of accounting for investments over which the Company is able to exercise significant influence.

Regulation

The Canadian Mainline, the BC System, Foothills and Trans Québec & Maritimes (TQM) are subject to the authority of the National Energy Board (NEB) and the Alberta System is regulated by the Alberta Energy and Utilities Board (EUB). The Gas Transmission Northwest System, North Baja and the other natural gas pipelines in the U.S. are subject to the authority of the Federal Energy Regulatory Commission (FERC). These natural gas transmission operations are regulated with respect to the determination of revenues, tolls, construction and operations. In order to appropriately reflect the economic impact of the regulators' decisions regarding the Company's revenues and tolls, and to thereby achieve a proper matching of revenues and expenses, the timing of recognition of certain revenues and expenses in these regulated businesses may differ from that otherwise expected under GAAP. The impact of rate regulation on TransCanada is provided in Note 11.

Revenue Recognition

Pipelines

In the Pipelines segment, revenues from the Canadian rate-regulated operations are recognized in accordance with decisions made by the NEB and EUB. Revenues from the U.S. rate-regulated operations are recorded in accordance with FERC rules and regulations. Revenues from non-regulated operations are recorded when products have been delivered or services have been performed.

Energy

i) Power
The majority of revenues from the Power business are derived from the sale of electricity from energy marketing activities and are recorded in the month of delivery. Revenues from the Power business are also derived from the sale of unutilized natural gas fuel and include the impact of energy derivative contracts, including financial swaps, futures contracts and options.

ii) Natural Gas Storage
The majority of the revenues earned from natural gas storage are derived from the sale of storage services recognized in accordance with the term of the gas storage contracts. Revenues earned on the sale of gas held in inventory are recorded in the month of delivery. These revenues include the impact of energy derivative contracts, including financial swaps, futures contracts and options.

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

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

Inventories
Inventories consisting of natural gas in storage, uranium, materials and supplies, including spare parts, are carried at the lower of average cost or net realizable value.

Plant, Property and Equipment

Pipelines
Plant, property and equipment of the Pipelines operations are carried at cost. Depreciation is calculated on a straight-line basis. Pipeline and compression equipment are depreciated at annual rates ranging from two to six per cent and metering and other plant equipment are depreciated at various rates. An allowance for funds used during construction, using the rate of return on rate base approved by the regulators, is capitalized and included in the cost of gas transmission plant.

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

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

Acquisitions and Goodwill
The Company accounts for business acquisitions using the purchase method of accounting and, accordingly, the assets and liabilities of the acquired entities are recorded at their estimated fair values at the date of acquisition. The excess of the purchase price over the fair value of net assets acquired is attributed to goodwill. Goodwill is not amortized for accounting purposes but is amortized for tax purposes. Goodwill is re-evaluated on an annual basis for impairment. Currently, all goodwill relates to Pipelines operations.

Power Purchase Arrangements
PPAs are long-term contracts for the purchase or sale of power on a predetermined basis. The initial payments for PPAs acquired are deferred and amortized over the terms of the contracts, which range from ten to 19 years. Certain PPAs under which TransCanada sells power are

accounted for as operating leases and, accordingly, the related plant, property and equipment are accounted for as assets under operating leases.

Stock Options

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

Income Taxes

As prescribed by the regulators, the taxes payable method of accounting for income taxes is used for tollmaking purposes for Canadian natural gas transmission operations. Under the taxes payable method, it is not necessary to provide for future income taxes. As permitted by Canadian GAAP, this method is also used for accounting purposes, since there is reasonable expectation that future taxes payable will be included in future costs of service and recorded in revenues at that time. The liability method of accounting for income taxes is used for the remainder of the Company's operations. Under this method, future tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future income tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Changes to these balances are recognized in income in the period in which they occur.

Canadian income taxes are not provided on the unremitted earnings of foreign investments which 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 statements of consolidated income, consolidated retained earnings and consolidated cash flows are translated at the exchange rates in effect at the time of the transaction. Translation adjustments are reflected in the foreign exchange adjustment in Shareholders' Equity.

Exchange gains or losses on the principal amounts of foreign currency debt and preferred securities related to the Alberta System and the Canadian Mainline are deferred until they are recovered in tolls.

Derivative Financial Instruments and Hedging Activities

The Company utilizes derivative and other financial instruments to manage its exposure to changes in foreign currency exchange rates, interest rates and energy commodity prices.

Derivatives are recorded at their fair value at each balance sheet date. Derivatives and other instruments must be designated and be effective to qualify for hedge accounting. For cash flow and fair value hedges, gains or losses relating to derivatives are deferred and recognized in the same period and in the same financial statement category as the corresponding hedged transactions. For hedges of net investments in self-sustaining foreign operations, exchange gains or losses on derivatives, after tax, and designated foreign currency denominated debt are offset against the exchange losses or gains arising on the translation of the financial statements of the foreign operations included in the foreign exchange adjustment account in Shareholders' Equity. Assessment of effectiveness for those derivatives classified as hedges occurs at inception and on an ongoing basis. In the event that a derivative does not meet the designation or effectiveness criteria, realized and unrealized gains or losses are recognized in income each period in the same financial statement category as the underlying transaction. Premiums paid or received with respect to derivatives that are hedges are deferred and amortized to income over the term of the hedge.

If a derivative that previously qualified as a hedge is settled, de-designated or ceases to be effective, the gain or loss at that date is deferred and recognized in the same period and in the same financial statement category as the corresponding hedged transactions. If an anticipated transaction is hedged and the transaction is no longer probable to occur, the related deferred gains or losses are recognized in income in the current period.

The recognition of gains and losses on the derivatives for the Canadian Mainline, the Alberta System, the BC System and Foothills exposures is determined through the regulatory process. The gains and losses on derivatives accounted for as part of rate-regulated accounting that do not meet the criteria for hedge accounting are deferred.

Asset Retirement Obligation

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

No amount is recorded for asset retirement obligations relating to the regulated natural gas transmission operation assets as it is not possible to make a reasonable estimate of the fair value of the liability due to the inability to determine the scope and timing of the asset retirements. Management believes it is reasonable to assume that all retirement costs associated with the regulated pipelines will be recovered through tolls in future periods.

For the hydroelectric power plant assets, as it is not possible to make a reasonable estimate of the fair value of the liability due to the inability to determine the scope and timing of the asset retirements, no amount has been recorded for asset retirement obligations. For the Bruce Power nuclear assets, as the lessor is responsible for decommissioning liabilities under the lease agreement, no amount has been recorded for asset retirement obligations.

Employee Benefit and Other Plans

The Company sponsors defined benefit pension plans (DB Plans). The cost of defined benefit pensions and other post-employment benefits earned by employees is actuarially determined using the projected benefit method pro-rated on service and Management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market-related values based on a five-year moving average value for all plan assets. Past service costs are amortized over the expected average remaining service life of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the fair value of plan assets is amortized over the average remaining service period of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

The Company has broad-based, medium-term employee incentive plans, which grant units to each eligible employee and are payable in cash. Employees have the option of designating, in advance of the payout determination, some or all of their payment to purchase shares through TransCanada's stock savings plan. 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 employee's continued employment during a specified period and achievement of specified corporate performance targets.

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

NOTE 2 SEGMENTED INFORMATION

Effective June 1, 2006, TransCanada revised the composition and names of its reportable business segments to Pipelines and Energy. The financial reporting of these segments was aligned to reflect the internal organizational structure of the Company. Pipelines principally comprises the Company's pipelines in Canada, the U.S. and Mexico. Energy includes the Company's power operations, natural gas storage business and LNG projects in Canada and the U.S. The segmented information has been retroactively restated to reflect the changes in reportable segments. These changes had no impact on consolidated income. These changes resulted in increases to net income in the Energy segment of $5 million in 2005 and $2 million in 2004, and corresponding decreases to net income in the Pipelines segment for the same years.

NET INCOME/(LOSS)[1]

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

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

Year ended December 31, 2004 (millions of dollars)	Pipelines	Energy	Corporate	Total
Revenues	3,854	1,643	–	5,497
Plant operating costs and other	(1,161)	(451)	(3)	(1,615)
Commodity purchases resold	–	(940)	–	(940)
Depreciation	(871)	(77)	–	(948)
	1,822	175	(3)	1,994
Financial charges and non-controlling interests	(848)	(9)	(79)	(936)
Financial charges of joint ventures	(59)	(4)	–	(63)
Income from equity investments	83	130	–	213
Interest income and other	8	14	37	59
Gains on sale of assets	7	197	–	204
Income taxes	(429)	(105)	43	(491)
Net income from continuing operations	584	398	(2)	980
Net income from discontinued operations				52
Net Income				1,032

[1] In determining the net income of each segment, certain expenses such as indirect financial charges and related income taxes are not allocated to business segments.

TOTAL ASSETS

December 31 (millions of dollars)	2006	2005
Pipelines	18,320	17,872
Energy	6,500	5,303
Corporate	1,089	938
	25,909	24,113

GEOGRAPHIC INFORMATION

Year ended December 31 (millions of dollars)	2006	2005	2004
Revenues[(1)]			
Canada – domestic	4,956	3,499	3,214
Canada – export	972	1,160	1,261
United States and other	1,592	1,465	1,022
	7,520	6,124	5,497

(1) Revenues are attributed to countries based on country of origin of product or service.

December 31 (millions of dollars)	2006	2005
Plant, Property and Equipment		
Canada	16,204	15,647
United States	5,109	4,306
Mexico	174	85
	21,487	20,038

CAPITAL EXPENDITURES

Year ended December 31 (millions of dollars)	2006	2005	2004
Pipelines	560	244	221
Energy	976	506	305
Corporate	36	4	4
	1,572	754	530

NOTE 3 PLANT, PROPERTY AND EQUIPMENT

December 31 (millions of dollars)	2006 Cost	2006 Accumulated Depreciation	2006 Net Book Value	2005 Cost	2005 Accumulated Depreciation	2005 Net Book Value
Pipelines						
Canadian Mainline						
Pipeline	**8,850**	**3,911**	**4,939**	8,701	3,665	5,036
Compression	**3,343**	**1,181**	**2,162**	3,341	1,066	2,275
Metering and other	**346**	**136**	**210**	359	134	225
	12,539	**5,228**	**7,311**	12,401	4,865	7,536
Under construction	**23**	**–**	**23**	15	–	15
	12,562	**5,228**	**7,334**	12,416	4,865	7,551
Alberta System						
Pipeline	**5,120**	**2,352**	**2,768**	5,020	2,203	2,817
Compression	**1,510**	**760**	**750**	1,493	676	817
Metering and other	**806**	**271**	**535**	799	247	552
	7,436	**3,383**	**4,053**	7,312	3,126	4,186
Under construction	**98**	**–**	**98**	25	–	25
	7,534	**3,383**	**4,151**	7,337	3,126	4,211
GTN(1)						
Pipeline	**1,386**	**111**	**1,275**	1,381	60	1,321
Compression	**512**	**32**	**480**	507	15	492
Metering and other	**89**	**–**	**89**	90	–	90
	1,987	**143**	**1,844**	1,978	75	1,903
Under construction	**17**	**–**	**17**	18	–	18
	2,004	**143**	**1,861**	1,996	75	1,921
Foothills						
Pipeline	**815**	**405**	**410**	815	377	438
Compression	**377**	**141**	**236**	377	128	249
Metering and other	**72**	**35**	**37**	71	31	40
	1,264	**581**	**683**	1,263	536	727
Joint Ventures and Other						
Great Lakes	**1,187**	**600**	**587**	1,181	566	615
Northern Border(2)	**1,451**	**585**	**866**	–	–	–
Other(3)	**2,274**	**615**	**1,659**	2,064	522	1,542
	4,912	**1,800**	**3,112**	3,245	1,088	2,157
	28,276	**11,135**	**17,141**	26,257	9,690	16,567
Energy(4)						
Nuclear(5)	**1,349**	**214**	**1,135**	1,265	143	1,122
Natural gas	**1,636**	**383**	**1,253**	1,121	347	774
Hydro	**592**	**21**	**571**	598	9	589
Natural gas storage	**344**	**22**	**322**	45	20	25
Other	**284**	**72**	**212**	117	55	62
	4,205	**712**	**3,493**	3,146	574	2,572
Under construction	**809**	**–**	**809**	872	–	872
	5,014	**712**	**4,302**	4,018	574	3,444
Corporate	**65**	**21**	**44**	73	46	27
	33,355	**11,868**	**21,487**	30,348	10,310	20,038

(1) Gas Transmission Northwest System and North Baja system (collectively GTN).

(2) In April 2006, PipeLines LP acquired an additional 20 per cent general partnership interest in Northern Border, bringing its total general partnership interest to 50 per cent. Northern Border became a jointly controlled entity and TransCanada commenced proportionately consolidating its investment in Northern Border on a prospective basis. At December 31, 2006, the Company's effective ownership, net of non-controlling interests, is 6.7 per cent (2005 – 4.0 per cent) as a result of the Company holding a 13.4 per cent interest in PipeLines LP.

(3) Includes $4 million of plant under construction (2005 – $85 million).

(4) Certain power generation facilities are accounted for as assets under operating leases. At December 31, 2006, the net book value of these facilities was $81 million (2005 – $87 million). In 2006, revenues of $13 million (2005 – $23 million) were recognized through the sale of electricity under the related PPAs.

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

NOTE 4 OTHER ASSETS

December 31 (millions of dollars)	**2006**	2005
PPAs[1]	**767**	825
Pension and other benefit plans	**268**	304
Regulatory assets	**171**	169
Derivative contracts	**142**	209
Hedging deferrals	**152**	118
Loans and advances[2]	**121**	91
Debt issue costs	**77**	72
Deferred project development costs[3]	**70**	25
Other	**210**	239
	1,978	2,052

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

	2006			2005		
December 31 (millions of dollars)	**Cost**	**Accumulated Amortization**	**Net Book Value**	Cost	Accumulated Amortization	Net Book Value
PPAs	**915**	**148**	**767**	915	90	825

The amortization expense for the PPAs was $58 million for the year ended December 31, 2006 (2005 – $24 million; 2004 – $24 million). The expected amortization expense in each of the next five years approximates: 2007 – $58 million; 2008 – $58 million; 2009 – $58 million; 2010 – $58 million; and 2011 – $57 million.

(2) The December 31, 2006 balance includes a $118-million loan (2005 – $87 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 (MGP) project. The ability to recover this investment remains dependent upon the successful outcome of the project.

(3) The December 31, 2006 balance includes $39 million (2005 – $6 million) and $31 million (2005 – $19 million) related to the Keystone oil project and the Broadwater LNG project, respectively.

NOTE 5 JOINT VENTURE INVESTMENTS

		TransCanada's Proportionate Share				
		Income Before Income Taxes Year ended December 31			Net Assets December 31	
(millions of dollars)	Ownership Interest[1]	**2006**	2005	2004	**2006**	2005
Pipelines						
Great Lakes	50.0%	**69**	73	86	**370**	375
Iroquois	44.5%[2]	**25**	29	28	**194**	190
TQM	50.0%	**11**	13	13	**75**	73
Northern Border	6.7%[3]	**47**	–	–	**634**	–
Other	Various[4]	**11**	15	12	**26**	67
Energy						
Bruce A	48.7%[5]	**75**	19	–	**916**	563
Bruce B	31.6%[5]	**140**	5	–	**425**	434
ASTC Power Partnership	50.0%[6]	**–**	–	–	**82**	88
Power LP	[7]	**–**	25	32	**–**	–
CrossAlta	60.0%	**64**	31	20	**36**	30
Portlands Energy	50.0%[8]	**–**	–	–	**90**	–
Cartier Wind	62.0%[9]	**2**	–		**172**	
		444	210	191	**3,020**	1,820

(1) All ownership interests are as at December 31, 2006. Changes due to the February 22, 2007 acquisition of ANR are discussed in Note 23 "Subsequent Events".

(2) In June 2005, the Company acquired an additional 3.5 per cent ownership interest in Iroquois.

(3) In April 2006, PipeLines LP acquired an additional 20 per cent general partnership interest in Northern Border, bringing its total general partnership interest to 50 per cent. Northern Border became a jointly controlled entity and TransCanada commenced proportionately consolidating its investment in Northern Border on a prospective basis. At December 31, 2006, the Company's effective ownership, net of non-controlling interests, was 6.7 per cent (2005 – 4.0 per cent) as a result of the Company holding a 13.4 per cent interest in PipeLines LP.

(4) In December 2006, PipeLines LP acquired an additional 49 per cent general partnership interest in Tuscarora. As a result of this transaction, PipeLines LP owns or controls 99 per cent of Tuscarora. PipeLines LP began consolidating its investment in Tuscarora at the date of this additional acquisition. At December 31, 2006, the Company effectively owned or controled an aggregate 14.3 per cent (2005 – 7.6 per cent) interest in Tuscarora of which 13.3 per cent was held indirectly through TransCanada's 13.4 per cent interest in PipeLines LP and the remaining one per cent was owned directly.

(5) TransCanada acquired a 47.4 per cent ownership interest in Bruce A on October 31, 2005. The Company increased its ownership interest in Bruce A to 48.7 per cent during 2006 (December 31, 2005 – 47.9 per cent) as a result of certain other partners not participating in capital contributions to Bruce A. The Company proportionately consolidated its investments in Bruce A and Bruce B, on a prospective basis, effective October 31, 2005.

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

(7) In April 2004, the Company's interest in TransCanada Power, L.P. (Power LP) decreased to 30.6 per cent from 35.6 per cent. In August 2005, the Company sold its 30.6 per cent interest in Power LP.

(8) Portlands Energy is a limited partnership between Ontario Power Generation and TransCanada, with both parties having a 50 per cent interest.

(9) TransCanada proportionately consolidates 62 per cent of the assets, liabilities, revenues and expenses of its Cartier Wind project. Baie-des-Sables began operating in November 2006.

Summarized Financial Information of Joint Ventures

Year ended December 31 (millions of dollars)	**2006**	2005	2004
Income			
Revenues	**1,379**	687	572
Plant operating costs and other	**(689)**	(328)	(240)
Depreciation	**(162)**	(93)	(90)
Financial charges and other	**(84)**	(56)	(51)
Proportionate share of income before income taxes of joint ventures	**444**	210	191

Year ended December 31 (millions of dollars)	**2006**	2005	2004
Cash Flows			
Operating activities	**645**	346	270
Investing activities	**(641)**	(133)	(287)
Financing activities(1)	**(31)**	(152)	35
Effect of foreign exchange rate changes on cash and short-term investments	**9**	(1)	(5)
Proportionate share of (decrease)/increase in cash and short-term investments of joint ventures	**(18)**	60	13

(1) Financing activities include cash outflows resulting from distributions paid to TransCanada of $470 million (2005 – $201 million; 2004 – $158 million) and cash inflows resulting from capital contributions paid by TransCanada of $452 million (2005 – $92 million and 2004 – nil).

December 31 (millions of dollars)	**2006**	2005
Balance Sheet		
Cash and short-term investments	**127**	123
Other current assets	**304**	281
Plant, property and equipment	**4,110**	2,707
Other assets/(deferred amounts) (net)	**78**	(45)
Current liabilities	**(443)**	(291)
Long-term debt	**(1,136)**	(937)
Future income taxes	**(20)**	(18)
Proportionate share of net assets of joint ventures	**3,020**	1,820

NOTE 6 LONG-TERM INVESTMENTS

		TransCanada's Share							
		Distributions from Equity Investments Year ended December 31			Income from Equity Investments Year ended December 31			Equity Investments December 31	
(millions of dollars)	Ownership Interest	**2006**	2005	2004	**2006**	2005	2004	**2006**	2005
Pipelines									
Northern Border	(1)	**13**	76	79	**13**	61	65	**–**	315
TransGas	46.5%(2)	**7**	6	8	**11**	11	11	**66**	62
Other	Various	**4**	10	13	**9**	7	7	**5**	23
Energy									
Bruce B	31.6%(3)	**–**	84	–	**–**	168	130	**–**	–
		24	176	100	**33**	247	213	**71**	400

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

(2) TransGas de Occidente S.A. (TransGas).

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

NOTE 7 ACQUISITIONS AND DISPOSITIONS

Acquisitions

Pipelines

Tuscarora

In December 2006, PipeLines LP acquired an additional 49 per cent controlling general partner interest in Tuscarora, subject to closing adjustments, for US$100 million, with the option to purchase Sierra Pacific Resources' remaining one per cent interest in Tuscarora in approximately one year. In addition, the Company indirectly assumed 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 include opportunities for expansion and a stronger competitive position.

As a result of this transaction, PipeLines LP owns or controls 99 per cent of Tuscarora. At December 31, 2006, TransCanada's effective ownership in Tuscarora, net of non-controlling interests, was 14.3 per cent as a result of it holding a 13.4 per cent interest in PipeLines LP, and its direct ownership of the remaining one per cent of Tuscarora. PipeLines LP began consolidating its investment in Tuscarora at the date of acquisition. In connection with this transaction, TransCanada became the operator of Tuscarora in December 2006.

Northern Border Pipeline

In April 2006, PipeLines LP 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. 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 include opportunities for expansion and a stronger competitive position.

This transaction increased PipeLines LP's total general partnership interest in Northern Border to 50 per cent. At December 31, 2006, TransCanada's effective ownership, net of non-controlling interests, was 6.7 per cent as a result of it holding a 13.4 per cent interest in PipeLines LP. PipeLines LP proportionately consolidated its 50 per cent interest in Northern Border at the date of acquisition. In connection with this transaction, TransCanada expects to become the operator of Northern Border in April 2007.

Energy

Sheerness PPA
Effective December 31, 2005, TransCanada acquired the remaining rights and obligations of the Sheerness PPA from the Alberta Balancing Pool for $585 million. The PPA terminates December 2021.

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

TC Hydro
In April 2005, TransCanada acquired certain hydroelectric generation assets from USGen New England, Inc. for approximately US$503 million. Substantially all of the purchase price was allocated to plant, property and equipment.

Dispositions

The pre-tax gains on sale of assets comprise the following.

Year ended December 31 (millions of dollars)	**2006**	2005	2004
Gain on sale of Northern Border Partners, L.P. interest	**23**	–	–
Gains related to Power LP	**–**	245	197
Gain on sale of Paiton Energy[1]	**–**	118	–
Gain on sale of PipeLines LP units	**–**	82	–
Gain on sale of Millennium[1]	**–**	–	7
	23	445	204

[1] PT Paiton Energy Company (Paiton Energy); Millennium Pipeline project (Millennium).

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

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

In April 2004, TransCanada sold the ManChief and Curtis Palmer power facilities to Power LP for $539 million (US$403 million) plus closing adjustments of $17 million (US$13 million) and recognized an after-tax gain on sale of $15 million. The net gain was recorded in the Energy segment and the Company recorded a $10-million income tax charge.

At a special meeting held on April 29, 2004, Power LP's unitholders approved an amendment to the terms of the Power LP Partnership Agreement to remove Power LP's obligation to redeem all units not owned by TransCanada at June 30, 2017. TransCanada was required to fund this redemption, thus the removal of Power LP's obligation eliminated this requirement. The removal of the obligation and the reduction in TransCanada's ownership interest in Power LP resulted in a gain of $172 million.

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

PipeLines LP
In March and April 2005, TransCanada sold 3,574,200 common units of PipeLines LP for net proceeds of $153 million and recorded an after-tax gain of $49 million. The net gain was recorded in the Pipelines segment and the Company recorded a $33-million income tax charge, including $51 million of current income tax expense, on this transaction. Subsequent to these transactions, TransCanada owned a 13.4 per cent interest in PipeLines LP represented by a general partner interest of 2.0 per cent and an 11.4 per cent limited partner interest.

NOTE 8 LONG-TERM DEBT

		2006		2005	
	Maturity Dates	Outstanding December 31[1]	Weighted Average Interest Rate[2]	Outstanding December 31[1]	Weighted Average Interest Rate[2]
TRANSCANADA PIPELINES LIMITED					
First Mortgage Pipe Line Bonds					
Pounds Sterling (2006 and 2005 – £25)	2007	**57**	**16.5%**	50	16.5%
Debentures					
Canadian dollars	2008 to 2020	**1,355**	**10.9%**	1,355	10.9%
U.S. dollars (2006 and 2005 – US$600)	2012 to 2021	**699**	**9.5%**	700	9.5%
Medium-Term Notes					
Canadian dollars	2007 to 2031	**3,848**	**6.0%**	3,228	6.4%
U.S. dollars (2006 – US$2,223; 2005 – US$1,841)	2009 to 2036	**2,590**	**5.8%**	2,146	5.8%
Subordinated Debentures					
U.S. dollars (2005 – US$57)		**–**		66	9.1%
		8,549		7,545	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian dollars	2007 to 2024	**564**	**11.6%**	585	11.6%
U.S. dollars (2006 and 2005 – US$375)	2012 to 2023	**437**	**8.2%**	437	8.2%
Medium-Term Notes					
Canadian dollars	2007 to 2030	**609**	**7.1%**	665	7.2%
U.S. dollars (2006 and 2005 – US$33)	2026	**38**	**7.5%**	38	7.5%
		1,648		1,725	
GAS TRANSMISSION NORTHWEST CORPORATION					
Unsecured Debentures and Notes					
U.S. Dollars (2006 and 2005 – US$400)	2010 to 2035	**466**	**5.3%**	466	5.3%
TC PIPELINES, LP					
Unsecured Loan					
U.S. dollars (2006 – US$397; 2005 – US$14)	2007	**463**	**5.4%**	16	5.6%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Secured Notes					
U.S. dollars (2006 – US$226; 2005 – US$241)	2018	**263**	**5.9%**	281	5.9%
TUSCARORA GAS TRANSMISSION COMPANY					
Senior Unsecured Notes					
U.S. dollars (2006 – US$74)	2010 to 2012	**86**	**7.2%**		
OTHER					
Secured Notes					
U.S. dollars (2006 – US$24)	2011	**28**	**7.3%**		
		11,503		10,033	
Less: Current Portion of Long-Term Debt		**616**		393	
		10,887		9,640	

(1) Amounts outstanding are stated in millions of Canadian dollars; amounts denominated in currencies other than Canadian dollars are stated in millions.

(2) Weighted average interest rates are stated as at the respective outstanding dates. The effective weighted average interest rates resulting from swap agreements are as follows: TransCanada PipeLines Limited's (TCPL) U.S. dollar medium-term notes – 5.8 per cent (2005 – 5.9 per cent) and TCPL's U.S. dollar subordinated debentures in 2005 – 9.0 per cent.

Principal Repayments

Principal repayments on the long-term debt of the Company approximate: 2007 – $616 million; 2008 – $549 million; 2009 – $847 million; 2010 – $653 million; and 2011 – $883 million.

Debt Shelf Programs

At December 31, 2006, $500 million of medium-term note debentures were available for issue under a debt shelf program in Canada and US$500 million of debt securities were available for issue under a debt shelf program in the U.S. Under the Canadian debt shelf program, the Company issued $300 million of five year medium-term notes bearing interest of 4.3 per cent in January 2006 and $400 million of ten year medium-term notes bearing interest of 4.65 per cent in October 2006. In March 2006, the Company issued US$500 million of 30-year senior unsecured notes bearing interest of 5.85 per cent under the U.S. debt shelf program. Both the Canadian and U.S. debt shelf programs expired in January 2007.

PipeLines LP

In April 2006, PipeLines LP borrowed US$307 million under its unsecured credit facility to finance the cash portion of the purchase price of its acquisition of an additional 20 per cent interest in Northern Border. In December 2006, the credit facility was repaid in full and replaced with a US$410 million syndicated revolving credit and term loan agreement, of which US$397 million was drawn as at December 31, 2006. Borrowings under the credit and term loan agreement will bear interest at the London interbank offered rate plus an applicable margin.

First Mortgage Pipe Line Bonds

The Deed of Trust and Mortgage securing the Company's First Mortgage Pipe Line Bonds limits the specific and floating charges to those assets comprising the present and future Canadian Mainline and TCPL's present and future gas transportation contracts.

Debentures

Debentures issued by Nova Gas Transmission Ltd. (NGTL), amounting to $225 million, have retraction provisions which 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 have been made to December 31, 2006.

Medium-Term Notes

On February 15, 2007, the Company retired $275 million of 6.05 per cent medium-term notes.

Medium-term notes issued by NGTL, amounting to $50 million, have a provision entitling the holders to extend the maturity of the medium-term notes from the initial repayment date of 2007 to 2027. If extended, the interest rate would increase from 6.1 per cent to 7.0 per cent.

Financial Charges

Year ended December 31 (millions of dollars)	**2006**	2005	2004
Interest on long-term debt	**846**	849	864
Interest on short-term debt	**23**	23	7
Capitalized interest	**(60)**	(24)	(11)
Amortization and other financial charges	**16**	(12)	(2)
	825	836	858

The Company made interest payments of $771 million for the year ended December 31, 2006 (2005 – $838 million; 2004 – $864 million).

NOTE 9 LONG-TERM DEBT OF JOINT VENTURES

		2006		2005	
	Maturity Dates	Outstanding December 31[1]	Weighted Average Interest Rate[2]	Outstanding December 31[1]	Weighted Average Interest Rate[2]
Great Lakes					
Senior Unsecured Notes					
(2006 – US$225; 2005 – US$230)	2011 to 2030	**262**	**7.8%**	268	7.9%
Bruce Power					
Capital Lease Obligations	2018	**250**	**7.5%**	254	7.5%
Iroquois					
Senior Unsecured Notes					
(2006 and 2005 – US$165)	2010 to 2027	**192**	**7.5%**	192	7.5%
Bank Loan					
(2006 – US$15; 2005 – US$25)	2008	**17**	**6.2%**	29	4.3%
TQM					
Bonds	2009 to 2010	**138**	**6.0%**	138	6.0%
Term Loan	2010	**32**	**4.4%**	29	3.5%
Northern Border					
Senior Unsecured Notes					
(2006 – US$316)	2007 to 2021	**368**	**6.9%**	–	–
Other	2007 to 2012	**19**	**3.8%**	68	6.1%
		1,278		978	
Less: Current Portion of Long-Term Debt of Joint Ventures		**142**		41	
		1,136		937	

(1) Amounts outstanding represent TransCanada's proportionate share and are stated in millions of Canadian dollars; amounts denominated in U.S. dollars are stated in millions.

(2) Weighted average interest rates are stated as at the respective outstanding dates. At December 31, 2006, the effective weighted average interest rates resulting from swap agreements are as follows: Iroquois bank loan – 6.9 per cent (2005 – 5.4 per cent).

The long-term debt of joint ventures is non-recourse to TransCanada, except that TransCanada has provided certain pro-rata guarantees related to the capital lease obligations of Bruce Power. The security provided with respect to the debt by each joint venture is limited to the rights and assets of that joint venture and does not extend to the rights and assets of TransCanada, except to the extent of TransCanada's investment.

The Company's proportionate share of principal repayments resulting from maturities and sinking fund obligations of the non-recourse joint venture debt approximates: 2007 – $134 million; 2008 – $17 million; 2009 – $192 million; 2010 – $246 million; and 2011 – $21 million.

The Company's proportionate share of principal payments resulting from the capital lease obligations of Bruce Power approximates: 2007 – $8 million; 2008 – $9 million; 2009 – $11 million; 2010 – $13 million; and 2011 – $15 million.

Financial Charges of Joint Ventures

Year ended December 31 (millions of dollars)	**2006**	2005	2004
Interest on long-term debt	**67**	60	59
Interest on capital lease obligations	**19**	3	–
Short-term interest and other financial charges	**3**	1	2
Deferrals and amortization	**3**	2	2
	92	66	63

The Company's proportionate share of the interest payments of joint ventures was $73 million for the year ended December 31, 2006 (2005 – $62 million; 2004 – $58 million).

The Company's proportionate share of interest payments from the capital lease obligations of Bruce Power was $20 million for the year ended December 31, 2006 (2005 – $3 million; 2004 – nil).

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 the second to thirteenth renewals is for a period of two years.

NOTE 10 DEFERRED AMOUNTS

December 31 (millions of dollars)	**2006**	2005
Regulatory liabilities	**386**	597
Derivative contracts	**254**	212
Hedging deferrals	**84**	72
Employee benefit plans	**195**	168
Asset retirement obligations	**45**	33
Deferred revenue	**32**	42
Other	**33**	72
	1,029	1,196

NOTE 11 REGULATED BUSINESSES

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

Canadian Regulated Operations

Canadian natural gas transmission services are provided under gas transportation tariffs that provide for cost recovery including return of and return on capital as approved by the applicable regulatory authorities.

Rates charged by TransCanada's wholly owned and partially-owned Canadian regulated pipelines are typically set through a process that involves filing of an application for a change in rates with the regulator. Under the regulation, rates are underpinned by the total annual revenue requirement, which includes a specified annual return on capital, including debt and equity, and all necessary operating expenses, taxes and depreciation.

TransCanada's Canadian regulated pipelines have generally been regulated using a cost-of-service model where the forecast costs plus a return on capital equals the revenues for the upcoming year. To the extent that actual costs are more or less than the forecast costs, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in revenues at that time. Those costs for which the regulator does not allow the difference between actual and forecast costs to be deferred are included in the determination of net income in the year in which they are incurred.

The Canadian Mainline, the BC System, Foothills and TQM are regulated by the NEB under the National Energy Board Act. The Alberta System is regulated by the EUB primarily under the provisions of the Gas Utilities Act (Alberta) and the Pipeline Act (Alberta). The NEB and the EUB regulate the construction, operations, tolls and the determination of revenues of the Canadian natural gas transmission operations.

Canadian Mainline

In March 2006, TransCanada and its Canadian Mainline shippers entered into a negotiated settlement that addressed all elements of the Canadian Mainline's 2006 tolls (2006 Settlement). The 2006 Settlement was approved by the NEB in April 2006. Pursuant to the 2006 Settlement, the cost of capital in the Canadian Mainline's 2006 revenue requirement and resulting tolls were determined based on the RH-2-2004 Phase II proceeding relating to the 2004 cost of capital of the Canadian Mainline. The RH-2-2004 Phase II decision increased the deemed capital structure for the Canadian Mainline to 36 per cent from 33 per cent, effective January 1, 2004. The return on equity of the Canadian Mainline continues to be based on the NEB's approved rate of return on common equity (ROE) formula, which was established in the RH-2-94 Multi-Pipeline Cost of Capital proceeding.

Under the 2006 Settlement, the Canadian Mainline's operating, maintenance and administrative (OM&A) costs for 2006 were fixed and variances between the 2006 negotiated and actual level of OM&A costs accrued to TransCanada. All other cost and revenue component variances were treated on a full recovery basis. The allowed ROE in 2006 was 8.88 per cent.

Alberta System

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

Fixed costs are operating costs and certain other costs, including foreign exchange on interest payments, uninsured losses and amortization of severance costs. These costs were set for each of 2005, 2006 and 2007 and any difference between actual and forecast fixed costs will be included in the determination of net income in the year in which they are incurred. Costs other than fixed costs are forecast at the beginning of each year and included in the calculation of the revenue requirement. Any variance between the forecast and actual costs incurred will be included in a deferral account and adjusted in the following year's revenue requirement. The settlement also set the ROE using the formula for determining the annual generic ROE established in the EUB's General Cost of Capital Decision 2004-052 on a deemed common equity of 35 per cent for all three years. The allowed ROE in 2006 was 8.93 per cent.

Other Canadian Pipelines

Similar to the Canadian Mainline, the NEB approves pipeline tolls on an annual cost of service basis for the BC System, 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 a 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 included in the following year's tolls. The ROE for these Canadian pipelines is based on the NEB's approved ROE formula which was established in the RH-2-94 Multi-Pipeline Cost of Capital proceeding, being 8.88 per cent in 2006. The deemed equity component of each of the pipelines' capital structure was set at 36 per cent for the BC System and Foothills and 30 per cent for TQM for 2006.

U.S. Regulated Operations

TransCanada's wholly owned and partially-owned U.S. pipelines are 'natural gas companies' operating under the provisions of the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, 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.

Gas Transmission Northwest System and North Baja System

Rates and tariffs of the Gas Transmission Northwest System and North Baja have been approved by the FERC. These two systems operate under fixed rate models, whereby maximum and minimum rates for various service types have been ordered by the FERC and under which each of the two systems are permitted to discount or negotiate rates on a non-discriminatory basis. General rates for mainline capacity on the Gas Transmission Northwest System were last reviewed by the FERC in a 1994 rate proceeding. A settlement of the 1994 rate proceeding, which set rate levels that remained in effect through December 2006, was approved by the FERC in 1996. In June 2006, Gas Transmission Northwest Corporation filed a general rate case under Section 4 of the Natural Gas Act of 1938. New rates on the Gas Transmission Northwest System went into effect on January 1, 2007, subject to refund, upon approval of final rates by the FERC. The FERC rate case hearing is scheduled to commence in October 2007. Rates for capacity on North Baja were established in 2002 in the FERC's initial order certificating construction and operations of North Baja.

Portland

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

Northern Border

As required by the provisions of the settlement of its last rate case, on November 1, 2005, Northern Border filed a rate case with the FERC. In December 2005, the FERC issued an order accepting the proposed rates but suspended their effectiveness until May 1, 2006. Since May 1, 2006, the new rates were collected subject to refund. The settlement was reached between Northern Border Pipeline and its customers and was supported by the FERC trial staff. The FERC approved the Northern Border settlement in November 2006.

Regulatory Assets and Liabilities

Year ended December 31 (millions of dollars)	**2006**	2005	Remaining Recovery/ Settlement Period
			(years)
Regulatory Assets			
Unrealized losses on derivatives – Canadian Mainline(1)	**44**	43	1 - 4
Unrealized losses on derivatives – BC System(1)	**33**	33	7
Foreign exchange reserve – Alberta System(2)	**33**	32	23
Phase II Preliminary Expenditures – Foothills(3)	**20**	23	9
Transitional other benefit obligations – Canadian Mainline(4)	**9**	10	10
Other	**32**	28	n/a
Total Regulatory Assets (Other Assets)	**171**	169	
Regulatory Liabilities			
Operating and debt service regulatory liabilities(5)	**70**	273	1
Foreign exchange on long-term debt – Canadian Mainline(6)	**195**	202	1 - 41
Foreign exchange on long-term debt – Alberta System(6)	**60**	59	6 - 23
Foreign exchange on long-term debt – BC System(6)	**19**	20	7
Post-retirement benefits other than pension – Gas Transmission Northwest System(7)	**19**	17	n/a
Other	**23**	26	n/a
Total Regulatory Liabilities (Deferred Amounts)	**386**	597	

(1) Unrealized losses on derivatives represent the net position of fair value gains and losses on cross-currency and interest-rate swaps which act as economic hedges. The cross-currency swaps relate to the Canadian Mainline and the BC System related foreign debt instruments. The Canadian Mainline interest-rate swaps were entered into as a result of the Mainline Interest Rate Management Program approved by the NEB as a component of the 1996 - 1999 Incentive Cost Recovery and Revenue Settlement. Interest savings or losses are determined when the interest swaps are settled. In the absence of rate-regulated accounting, Canadian GAAP would require the inclusion of these fair value losses in the operating results of the Canadian Mainline as they were not documented as hedges for accounting purposes. In the absence of rate-regulated accounting, pre-tax operating results of the Canadian Mainline for 2006 would have been $1 million lower (2005 – $8 million lower). Effective January 1, 2006, the BC System cross-currency swap has been designated and is effective to qualify for hedge accounting. The regulatory asset with respect to the BC System represents the unrealized losses for the ineffective period of the derivative from inception to December 31, 2005. In the absence of rate-regulated accounting, pre-tax operating results would have been the same (2005 – $2 million lower) for the BC System.

(2) The foreign exchange reserve account in the Alberta System, as approved by the EUB, is designed to facilitate the recovery or refund of foreign exchange gains and losses over the life of the foreign currency debt issues. The estimated gain/(loss) on foreign currency debt is amortized over the remaining years of the longest outstanding U.S. debt issue. The annual amortization amount is included in the determination of tolls for the year.

(3) Phase II Preliminary Expenditures are costs incurred by Foothills prior to 1981 related to development of Canadian facilities to deliver Alaskan gas that have been approved by the regulator for collection through straight-line amortization over the period November 1, 2002 to December 31, 2015. In the absence of rate-regulated accounting, GAAP would require these costs to be expensed in the year incurred, increasing pre-tax operating results in 2006 by $3 million (2005 – $2 million higher).

(4) The regulatory asset with respect to the transitional other benefit obligations is being amortized over 17 years, starting January 1, 2000. Amortization will be completed by December 31, 2016, at which time the full transitional obligation will have been recovered through tolls. In the absence of rate-regulated accounting, pre-tax operating results would have been $1 million higher (2005 – $1 million higher).

(5) Operating and debt service regulatory liabilities represent the accumulation of cost and revenue variances approved by the regulatory authority for inclusion in determination of the tolls for the immediate following calendar year. In the absence of rate-regulated accounting, GAAP would have required the inclusion of these variances in the operating results of the year in which the variances were incurred. Pre-tax operating results for 2006 and 2005 are the same as would have been the case in the absence of rate-regulated accounting.

(6) The foreign exchange on long-term debt of the Canadian Mainline, the Alberta System and the BC System represent the variance resulting from revaluing foreign currency denominated debt instruments from their historic foreign exchange rate to the current foreign exchange rate. Foreign exchange gains/(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.

(7) In Gas Transmission Northwest System's rates, an amount is recovered for post-retirement benefits other than pension (PBOP). This regulatory liability represents the difference between the amount collected in rates and the amount of PBOP expense determined under GAAP. In the absence of rate-regulated accounting, GAAP would require the inclusion of this amount in operating results and pre-tax operating results in 2006 would have been $2 million higher than reported (2005 – $1 million higher).

As prescribed by the regulators, the taxes payable method of accounting for income taxes is used for tollmaking purposes for Canadian regulated natural gas transmission operations. As permitted by GAAP, this method is also used for accounting purposes, since there is reasonable expectation that future income taxes payable will be included in future costs of service and recorded in revenues at that time. Consequently, future income tax liabilities have not been recognized as it is expected that when these amounts become payable, they will be recovered through future rate revenues. In the absence of rate-regulated accounting, GAAP would require the recognition of future income tax liabilities. If the liability method of accounting had been used, additional future income tax liabilities in the amount of $1,355 million at December 31, 2006 (2005 – $1,619 million) would have been recorded and would be recoverable from future revenues. In the second quarter of 2006, a reduction in enacted Canadian federal and provincial corporate future income tax rates resulted in a decrease of $182 million to this unrecorded future income tax liability. For the U.S. natural gas transmission operations, the liability method of accounting is used for both accounting and tollmaking purposes, whereby future income tax assets and liabilities are recognized based on the differences between financial statement carrying amounts and the tax basis of such assets and liabilities. As this method is also used for tollmaking purposes for the U.S. natural gas transmission operations, the current year's revenues include a tax provision which is calculated based on the liability method of accounting and therefore, there is no recognition of a related regulatory asset or liability.

NOTE 12 PREFERRED SECURITIES

The US$460 million (2006 and 2005 – $536 million) 8.25 per cent preferred securities of TCPL are redeemable by the issuer at par at any time. The issuer may elect to defer interest payments on the preferred securities and settle the deferred interest in either cash or common shares.

NOTE 13 NON-CONTROLLING INTERESTS

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

December 31 (millions of dollars)	**2006**	2005
Preferred shares of subsidiary	**389**	389
Non-controlling interest in PipeLines LP	**287**	318
Other	**79**	76
	755	783

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

Year ended December 31 (millions of dollars)	**2006**	2005	2004
Preferred share dividends of subsidiary	**22**	22	22
Non-controlling interest in PipeLines LP	**43**	52	46
Other	**13**	10	10
	78	84	78

Preferred Shares of Subsidiary

December 31	Number of Shares	Dividend Rate Per Share	Redemption Price Per Share	**2006**	2005
	(thousands)			(millions of dollars)	(millions of dollars)
Cumulative First Preferred Shares of Subsidiary					
Series U	4,000	$2.80	$50.00	**195**	195
Series Y	4,000	$2.80	$50.00	**194**	194
				389	389

The authorized number of preferred shares of TCPL issuable in series is unlimited. All of the cumulative first preferred shares of subsidiary are without par value.

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

Non-Controlling Interest in PipeLines LP and Other

As at December 31, 2006, the non-controlling interest in PipeLines LP represents the 86.6 per cent of the limited partnership held by the limited partners. Other non-controlling interests include the 38.3 per cent non-controlling interest in Portland held by an unrelated partner. Revenues received from PipeLines LP and Portland with respect to services provided by TransCanada for the year ended December 31, 2006 were $1 million (2005 – $1 million; 2004 – $1 million) and $6 million (2005 – $6 million; 2004 – $4 million), respectively.

NOTE 14 COMMON SHARES

	Number of Shares	Amount
	(thousands)	(millions of dollars)
Outstanding at January 1, 2004	483,200	4,679
Exercise of options	1,714	32
Outstanding at December 31, 2004	484,914	4,711
Exercise of options	2,322	44
Outstanding at December 31, 2005	487,236	4,755
Exercise of options	**1,739**	**39**
Outstanding at December 31, 2006	**488,975**	**4,794**

Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares of no par value.

Net Income Per Share

Basic and diluted earnings per share are calculated based on the weighted average number of common shares outstanding during the year of 488.0 million and 490.6 million (2005 – 486.2 million and 489.1 million; 2004 – 484.1 million and 486.7 million), respectively. The increase in the weighted average number of shares for the diluted earnings per share calculation is due to the options exercisable under TransCanada's Stock Option Plan.

Stock Options

	Number of Options	Weighted Average Exercise Prices	Options Exercisable
	(thousands)		(thousands)
Outstanding at January 1, 2004	10,355	$19.73	7,588
Granted	1,331	$26.85	
Exercised	(1,714)	$18.42	
Cancelled or expired	(7)	$24.25	
Outstanding at December 31, 2004	9,965	$20.90	7,239
Granted	1,075	$30.21	
Exercised	(2,322)	$18.57	
Cancelled or expired	(4)	$25.34	
Outstanding at December 31, 2005	8,714	$22.67	6,300
Granted	**1,841**	**$34.48**	
Exercised	**(1,739)**	**$21.44**	
Cancelled or expired	**(17)**	**$30.98**	
Outstanding at December 31, 2006	**8,799**	**$25.37**	**5,888**

The following table summarizes information for stock options outstanding at December 31, 2006.

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
	(thousands)	(years)		(thousands)	
$10.03 to $20.27	1,321	3.9	$16.09	1,321	$16.09
$20.58 to $21.86	1,703	4.6	$21.15	1,703	$21.15
$22.33 to $24.49	1,349	3.0	$22.75	1,349	$22.75
$24.61 to $26.85	1,590	3.9	$26.33	1,169	$26.14
$30.09 to $33.08	1,647	5.7	$31.25	339	$30.09
$35.23 to $36.67	1,189	6.2	$35.25	7	$36.67
	8,799	4.6	$25.37	5,888	$21.91

At December 31, 2006, an additional two million common shares were reserved for future issuance under TransCanada's Stock Option Plan. In 2006, TransCanada issued 1,841,000 options to purchase common shares at an average price of $34.48 under the Company's Stock Option Plan and the weighted average fair value of each option was determined to be $3.53. The Company used the Black-Scholes model for determining the fair value of options granted using the following weighted average assumptions being four years (2005 and 2004 – four years) of expected life, 4.1 per cent (2005 – 4.0 per cent; 2004 – 3.3 per cent) interest rate, 14 per cent (2005 – 15 per cent; 2004 – 18 per cent) volatility and 3.7 per cent (2005 – 3.3 per cent; 2004 – 4.3 per cent) dividend yield. The amount expensed for stock options, with a corresponding increase in contributed surplus for the year ended December 31, 2006, was $3 million (2005 – $3 million; 2004 – $3 million).

Shareholder Rights Plan

The Company's Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Under certain circumstances, each common share is entitled to one right that entitles certain holders to purchase common shares of the Company at 50 per cent of the market price at that time.

Dividend Reinvestment and Share Purchase Plan

In January 2007, TransCanada's Board of Directors authorized the issue of common shares from treasury at a discount of two per cent to participants in the Company's Dividend Reinvestment and Share Purchase Plan (DRP). Under this plan, eligible shareholders may reinvest their dividends and make optional cash payments to obtain additional TransCanada common shares. Previously, shares purchased through the DRP were purchased by TransCanada on the open market and provided to DRP participants at cost. Commencing with the dividend payable in

April 2007, the DRP shares will be provided to the participants at a two per cent discount to the average market price in the five days before dividend payment. The Company reserves the right to alter the discount or return to purchasing shares on the open market at any time.

NOTE 15 RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Company issues short-term and long-term debt, purchases and sells energy commodities, including amounts in foreign currencies, and invests in foreign operations. These activities result in exposures to changing interest rates, energy commodity prices and foreign currency exchange rates. The Company uses derivatives to manage the exposure that results from these activities. The use of derivatives is subject to the Company's overall risk management policies and procedures.

The fair value of foreign exchange and interest rate derivatives has been calculated using year-end market rates. The fair value of power, natural gas and heat rate derivatives has been calculated using estimated forward prices for the relevant period.

Net Investment in Foreign Operations

At December 31, 2006 and 2005, the Company had net investments in self-sustaining foreign operations with a U.S. dollar functional currency which created an exposure to changes in exchange rates. The Company uses U.S. dollar denominated debt and derivatives to hedge this exposure on an after-tax basis. The fair value for derivatives used to manage the exposure is shown in the table below.

Asset/(Liability) *December 31 (millions of dollars)*	Accounting Treatment	**2006** **Fair Value**	**2006** **Notional or Notional Principal Amount**	2005 Fair Value	2005 Notional or Notional Principal Amount
U.S. dollar cross-currency swaps (maturing 2007 to 2013)	Hedge	**58**	**U.S. 400**	119	U.S. 450
U.S. dollar forward foreign exchange contracts (maturing 2007)	Hedge	**(7)**	**U.S. 390**	5	U.S. 525
U.S. dollar options (maturing 2007)	Hedge	**(6)**	**U.S. 500**	–	U.S. 60

Reconciliation of Foreign Exchange Adjustment

December 31 (millions of dollars)	**2006**	2005
Balance at January 1 (loss)	**(90)**	(71)
Translation gains/(losses) on foreign currency denominated net assets(1)	**8**	(21)
(Losses)/gains on derivatives	**(9)**	23
Income taxes	**1**	(21)
Balance at December 31 (loss)	**(90)**	(90)

(1) The amount for 2006 includes gains of $6 million (2005 – $80 million) related to foreign currency denominated debt designated as a hedge.

Foreign Exchange and Interest Rate Management Activity

The Company manages the foreign exchange and interest rate risks related to its U.S. dollar denominated debt and transactions and interest rate exposures of the Canadian Mainline, the Alberta System and the BC System through the use of foreign currency and interest rate derivatives. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms. The details of the foreign exchange and interest rate derivatives are shown in the table below.

Asset/(Liability) *December 31 (millions of dollars)*	Accounting Treatment	**2006** **Fair Value**	**2006** **Notional or Notional Principal Amount**	2005 Fair Value	2005 Notional or Notional Principal Amount
Foreign Exchange					
Cross-currency and interest-rate swaps					
(maturing 2013)	Hedge	**(32)**	**136/U.S. 100**	–	–
(maturing 2010 to 2012)	Non-hedge	**(52)**	**227/U.S. 157**	(86)	363/U.S. 257
		(84)		(86)	
Interest Rate					
Interest rate swaps					
Canadian dollars					
(maturing 2007 to 2008)	Hedge	**2**	**100**	4	100
(maturing 2007 to 2009)	Non-hedge	**5**	**300**	7	374
		7		11	
U.S. dollars					
(maturing 2007 to 2009)	Non-hedge	**4**	**U.S. 100**	5	U.S. 100

The Company manages the foreign exchange and interest rate exposures of its other businesses through the use of foreign currency and interest rate derivatives. The details of these foreign currency and interest rate derivatives are shown in the table below.

Asset/(Liability) *December 31 (millions of dollars)*	Accounting Treatment	**2006** **Fair Value**	**2006** **Notional or Notional Principal Amount**	2005 Fair Value	2005 Notional or Notional Principal Amount
Foreign Exchange					
Options (maturing 2007)	Non-hedge	**–**	**U.S. 95**	1	U.S. 195
Forward foreign exchange contracts					
	Hedge	**–**	**–**	2	U.S. 29
(maturing 2007)	Non-hedge	**(3)**	**U.S. 250**	1	U.S. 208
		(3)		4	
Interest Rate					
Options (maturing 2007)	Non-hedge	**–**	**U.S. 50**	–	–
Interest rate swaps					
Canadian dollar					
(maturing 2007 to 2011)	Hedge	**–**	**150**	1	100
(maturing 2009 to 2011)	Non-hedge	**–**	**164**	1	423
		–		2	
U.S. dollars					
(maturing 2011 to 2017)	Hedge	**(2)**	**U.S. 350**	–	U.S. 50
(maturing 2007 to 2016)	Non-hedge	**9**	**U.S. 450**	18	U.S. 550
		7		18	

Foreign exchange gains included in Other Expenses/(Income) for the year ended December 31, 2006 are $4 million (2005 – $19 million; 2004 – $6 million).

Certain of the Company's joint ventures use interest rate derivatives to manage interest rate exposures. The Company's proportionate share of the fair value of these outstanding derivatives at December 31, 2006 and 2005 was nil.

Energy Price Risk Management

The Company executes power, natural gas and heat rate derivatives for overall management of its asset portfolio. Heat rate contracts are contracts for the sale or purchase of power that are priced based on a natural gas index. The fair value and notional volumes of contracts for differences and the swap, option, future and heat rate contracts are shown in the tables below.

Energy

Asset/(Liability)

December 31 (millions of dollars)	Accounting Treatment	**2006** **Fair Value**	2005 Fair Value
Power – swaps and contracts for differences			
(maturing 2007 to 2011)	Hedge	**(179)**	(130)
(maturing 2007 to 2010)	Non-hedge	**(7)**	13
Gas – swaps, futures and options			
(maturing 2007 to 2016)	Hedge	**(66)**	17
(maturing 2007 to 2008)	Non-hedge	**30**	(11)
Heat rate contracts	Non-hedge	**–**	–

Notional Volumes

		Power (GWh)[1]		**Gas (Bcf)[1]**	
December 31, 2006	**Accounting Treatment**	**Purchases**	**Sales**	**Purchases**	**Sales**
Power – swaps and contracts for differences					
(maturing 2007 to 2011)	**Hedge**	**6,654**	**12,349**	**–**	**–**
(maturing 2007 to 2010)	**Non-hedge**	**1,402**	**964**	**–**	**–**
Gas – swaps, futures and options					
(maturing 2007 to 2016)	**Hedge**	**–**	**–**	**77**	**59**
(maturing 2007 to 2008)	**Non-hedge**	**–**	**–**	**11**	**15**
Heat rate contracts	**Non-hedge**	**–**	**9**	**–**	**–**
December 31, 2005					
Power – swaps and contracts for differences	Hedge	2,566	7,780	–	–
	Non-hedge	1,332	456	–	–
Gas – swaps, futures and options	Hedge	–	–	91	69
	Non-hedge	–	–	15	18
Heat rate contracts	Non-hedge	–	35	–	–

(1) Gigawatt hours (GWh); billion cubic feet (Bcf).

Certain of the Company's joint ventures use power derivatives to manage energy price risk exposures. The Company's proportionate share of the fair value of these outstanding power sales derivatives at December 31, 2006 was $55 million (2005 – $(38) million) and related to contracts which cover the period 2007 to 2010. The Company's proportionate share of the notional sales volumes of power associated with this exposure at December 31, 2006 was 4,500 GWh (2005 – 2,058 GWh).

Fair Value of Financial Instruments

The fair value of cash and short-term investments and notes payable approximates their carrying amounts due to the short period to maturity. The fair value of long-term debt, long-term debt of joint ventures and preferred securities is determined using market prices for the same or similar issues.

December 31 (millions of dollars)	2006 Carrying Amount	2006 Fair Value	2005 Carrying Amount	2005 Fair Value
Long-Term Debt				
TransCanada PipeLines Limited	**8,549**	**9,738**	7,545	9,071
NOVA Gas Transmission Ltd.	**1,648**	**2,111**	1,725	2,267
Gas Transmission Northwest Corporation	**466**	**450**	466	470
Portland Natural Gas Transmission System	**263**	**265**	281	292
TC PipeLines, LP	**463**	**463**	16	16
Tuscarora Gas Transmission Company	**86**	**94**		
Other	**28**	**28**		
Long-Term Debt of Joint Ventures	**1,278**	**1,295**	978	1,101
Preferred Securities	**536**	**532**	536	554

The fair value is provided solely for information purposes and is not recorded in the consolidated balance sheet.

Credit Risk

Credit risk results from the possibility that a counterparty to a derivative in which the Company has an unrealized gain fails to perform according to the terms of the contract. Credit exposure is minimized through the use of established credit management techniques, including formal assessment processes, contractual and collateral requirements, master netting arrangements and credit exposure limits. At December 31, 2006, for foreign currency and interest rate derivatives, total credit risk and the largest credit exposure to a single counterparty were $38 million and $11 million, respectively. At December 31, 2006, for power, natural gas and heat rate derivatives, total credit risk and the largest credit exposure to a single counterparty were $21 million and $11 million, respectively.

NOTE 16 INCOME TAXES

Provision for Income Taxes

Year ended December 31 (millions of dollars)	2006	2005	2004
Current			
Canada	**264**	499	373
Foreign	**37**	51	41
	301	550	414
Future			
Canada	**104**	(46)	34
Foreign	**71**	106	43
	175	60	77
	476	610	491

Geographic Components of Income

Year ended December 31 (millions of dollars)	2006	2005	2004
Canada	**1,161**	1,316	1,207
Foreign	**444**	587	342
Income from continuing operations before income taxes and non-controlling interests	**1,605**	1,903	1,549

Reconciliation of Income Tax Expense

Year ended December 31 (millions of dollars)	**2006**	2005	2004
Income from continuing operations before income taxes and non-controlling interests	**1,605**	1,903	1,549
Federal and provincial statutory tax rate	**32.5%**	33.6%	33.9%
Expected income tax expense	**522**	639	525
Income tax differential related to regulated operations	**72**	71	62
Higher effective foreign tax rates	**–**	2	2
Tax rate reductions[(1)]	**(33)**	–	–
Large corporations tax	**–**	15	21
Income from equity investments and non-controlling interests	**(27)**	(29)	(25)
Non-taxable portion of gains on sale of assets	**–**	(68)	(66)
Change in valuation allowance	**–**	–	(7)
Other[(2)]	**(58)**	(20)	(21)
Actual income tax expense	**476**	610	491

(1) In second quarter 2006, TransCanada recorded a $33-million future income tax benefit as a result of reductions in future Canadian federal and provincial corporate income tax rates enacted in that quarter.

(2) Includes income tax benefits of $51 million recorded in 2006 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)	**2006**	2005
Deferred costs	**65**	129
Other post-employment benefits	**45**	39
Deferred revenue	**6**	11
Other	**47**	50
	163	229
Less: Valuation allowance	**14**	14
Future income tax assets, net of valuation allowance	**149**	215
Difference in accounting and tax bases of plant, equipment and PPAs	**768**	637
Investments in subsidiaries and partnerships	**113**	131
Pension benefits	**59**	58
Unrealized foreign exchange gains on long-term debt	**39**	68
Other	**46**	24
Future income tax liabilities	**1,025**	918
Net future income tax liabilities	**876**	703

Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments which the Company does not intend to repatriate in the foreseeable future. If provision for these taxes had been made, future income tax liabilities would increase by approximately $72 million at December 31, 2006 (2005 – $61 million).

Income Tax Payments

Income tax payments of $494 million were made during the year ended December 31, 2006 (2005 – $531 million; 2004 – $419 million).

NOTE 17 NOTES PAYABLE

	2006		2005	
	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	**467**	**4.3%**	765	3.4%
U.S. dollars (2006 – nil; 2005 – US$169)	**–**	**–**	197	4.5%
	467		962	

Notes payable consists of commercial paper and line of credit drawings. At December 31, 2006, total credit facilities of $2.1 billion were available to support the Company's commercial paper programs and for general corporate purposes. Of this total, $1.5 billion was a committed five-year term syndicated credit facility. This facility is extendible on an annual basis and is revolving. In December 2006, the facility was extended to December 2011. The remaining amounts are either demand or non-extendible facilities.

At December 31, 2006, the Company had used approximately $190 million of its total lines of credit for letters of credit and to support its ongoing commercial arrangements. If 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. The cost to maintain the unused portion of the lines of credit was $2 million for the year ended December 31, 2006 (2005 – $2 million).

NOTE 18 ASSET RETIREMENT OBLIGATIONS

At December 31, 2006, the estimated undiscounted cash flows required to settle the asset retirement obligations with respect to the non-regulated operations in Pipelines were $39 million (2005 – $39 million), calculated using an inflation rate ranging from two to three per cent per annum. The estimated fair value of this liability was $9 million (2005 – $4 million) after discounting the estimated cash flows at rates ranging from 5.4 per cent to 6.6 per cent. At December 31, 2006, the expected timing of payment for settlement of the obligations is 23 years.

At December 31, 2006, the estimated undiscounted cash flows required to settle the asset retirement obligations with respect to the Energy business were $162 million (2005 – $114 million), calculated using an inflation rate ranging from two to three per cent per annum. The estimated fair value of this liability was $36 million (2005 – $29 million) after discounting the estimated cash flows at rates ranging from 5.4 per cent to 6.6 per cent. At December 31, 2006, the expected timing of payment for settlement of the obligations ranges from 11 to 33 years.

Reconciliation of Asset Retirement Obligations

(millions of dollars)	Pipelines	Energy	Total
Balance at January 1, 2004	1	8	9
New obligations and revisions in estimated cash flows	4	26	30
Removal of Power LP redemption obligations	–	(5)	(5)
Accretion expense	–	2	2
Balance at December 31, 2004	5	31	36
New obligations and revisions in estimated cash flows	(1)	1	–
Sale of Power LP	–	(5)	(5)
Accretion expense	–	2	2
Balance at December 31, 2005	4	29	33
New obligations and revisions in estimated cash flows	4	6	10
Accretion expense	1	1	2
Balance at December 31, 2006	**9**	**36**	**45**

NOTE 19 EMPLOYEE FUTURE BENEFITS

The Company sponsors DB Plans that cover substantially all employees. Benefits provided under the DB Plans are based on years of service and highest average earnings over three consecutive years of employment, and increase annually by a portion of the increase in the Consumer Products Index (CPI). Past service costs are amortized over the expected average remaining service life of employees, which is approximately 11 years.

The Company also provides its employees with 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 at December 31, 2006 was approximately 13 years.

In 2006, the Company expensed $2 million (2005 – $2 million; 2004 – $1 million) related to retirement savings plans for its U.S. employees.

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

The Company measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuation of the pension plans for funding purposes was as of January 1, 2007, and the next required valuation is as of January 1, 2008.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2006**	2005	**2006**	2005
Change in Benefit Obligation				
Benefit obligation – beginning of year	**1,282**	1,100	**148**	123
Current service cost	**39**	32	**3**	3
Interest cost	**65**	63	**8**	7
Employee contributions	**3**	3	**–**	–
Benefits paid	**(64)**	(60)	**(7)**	(6)
Actuarial loss/(gain)	**53**	149	**(2)**	21
Foreign exchange rate changes	**–**	(3)	**–**	–
Plan amendment	**–**	–	**(18)**	–
Curtailment	**–**	(2)	**–**	–
Benefit obligation – end of year	**1,378**	1,282	**132**	148
Change in Plan Assets				
Plan assets at fair value – beginning of year	**1,096**	970	**27**	26
Actual return on plan assets	**134**	119	**6**	2
Employer contributions	**95**	67	**7**	5
Employee contributions	**3**	3	**–**	–
Benefits paid	**(64)**	(60)	**(7)**	(6)
Foreign exchange rate changes	**–**	(3)	**–**	–
Plan assets at fair value – end of year	**1,264**	1,096	**33**	27
Funded status – plan deficit	**(114)**	(186)	**(99)**	(121)
Unamortized net actuarial loss	**291**	331	**39**	45
Unamortized past service costs	**32**	36	**(12)**	8
Accrued benefit asset/(liability), net of valuation allowance of nil	**209**	181	**(72)**	(68)

The accrued benefit asset/(liability) is included in the Company's balance sheet as follows.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2006**	2005	**2006**	2005
Other assets	**230**	268	**5**	4
Accounts payable	**–**	(70)	**–**	(7)
Deferred amounts	**(21)**	(17)	**(77)**	(65)
Total	**209**	181	**(72)**	(68)

Included in the above benefit obligation and fair value of plan assets at December 31 are the following amounts in respect of plans that are not fully funded.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2006**	2005	**2006**	2005
Benefit obligation	**(1,359)**	(1,263)	**(102)**	(124)
Plan assets at fair value	**1,243**	1,075	**–**	–
Funded status – plan deficit	**(116)**	(188)	**(102)**	(124)

The Company's expected contributions for the year ended December 31, 2007 are approximately $44 million for the pension benefit plans and approximately $5 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
2007	59	7
2008	62	7
2009	65	8
2010	68	8
2011	71	8
Years 2012 to 2016	406	42

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

	Pension Benefit Plans		Other Benefit Plans	
	2006	2005	**2006**	2005
Discount rate	**5.00%**	5.00%	**5.20%**	5.15%
Rate of compensation increase	**3.50%**	3.50%		

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan cost for years ended December 31 are as follows.

	Pension Benefit Plans			Other Benefit Plans		
	2006	2005	2004	**2006**	2005	2004
Discount rate	**5.00%**	5.75%	6.00%	**5.15%**	6.00%	6.25%
Expected long-term rate of return on plan assets	**6.90%**	6.90%	6.90%	**7.75%**	7.20%	
Rate of compensation increase	**3.50%**	3.50%	3.50%			

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for both the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and future expectations of the level and volatility of returns. Asset class benchmark returns, asset mix and anticipated benefit payments from plan assets are also considered in the determination of the overall expected rate of return. The discount rate is based on market interest rates of high quality bonds that match the timing and benefits expected to be paid under each plan.

For measurement purposes, a nine per cent annual rate of increase in the per capita cost of covered health care benefits was assumed for 2007. The rate was assumed to decrease gradually to five per cent for 2015 and remain at that level thereafter. A one percentage point increase or decrease 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	4	(3)
Effect on post-employment benefit obligation	8	(7)

The Company's net benefit cost is as follows.

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31 (millions of dollars)	**2006**	2005	2004	**2006**	2005	2004
Current service cost	**39**	32	28	**3**	3	3
Interest cost	**65**	63	58	**8**	7	7
Actual return on plan assets	**(134)**	(119)	(97)	**(6)**	(2)	(1)
Actuarial loss/(gain)	**53**	149	46	**(2)**	21	(12)
Plan amendment	**–**	–	–	**(18)**	–	–
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**23**	125	35	**(15)**	29	(3)
Difference between expected and actual return on plan assets	**63**	54	39	**4**	–	1
Difference between actuarial loss recognized and actual actuarial loss on accrued benefit obligation	**(27)**	(131)	(32)	**4**	(20)	13
Difference between amortization of past service costs and actual plan amendments	**4**	3	3	**19**	1	–
Amortization of transitional obligation related to regulated business	**–**	–	–	**2**	2	2
Net benefit cost recognized	**63**	51	45	**14**	12	13

The Company's pension plans' weighted average asset allocations at December 31, by asset category, and weighted average target allocation at December 31, by asset category, is as follows.

	Percentage of Plan Assets		**Target Allocation**
Asset Category	**2006**	2005	**2006**
Debt securities	**40%**	43%	**35% to 60%**
Equity securities	**60%**	57%	**40% to 65%**
	100%	100%	

Debt securities include the Company's debt in the amount of $4 million (0.3 per cent of total plan assets) and $3 million (0.3 per cent of total plan assets) at December 31, 2006 and 2005, respectively. Equity securities include the Company's common shares in the amounts of $6 million (0.5 per cent of total plan assets) and $5 million (0.5 per cent of total plan assets) at December 31, 2006 and 2005, 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

In addition to these plans, certain of the Company's joint ventures sponsor DB Plans, as well as post-employment benefits other than pensions, including defined life insurance and medical benefits beyond those provided by government-sponsored plans. The obligations of these plans are non-recourse to TransCanada. The amounts that follow represent TransCanada's proportionate share with respect to these plans.

Total cash payments for employee future benefits for 2006, consisting of cash contributed by the Company's joint ventures to DB Plans and other benefit plans was $25 million (2005 – $4 million).

The Company's joint ventures measure the benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuations of the pension plans for funding purposes were as of January 1, 2007, and the next required valuations will be as of January 1, 2008.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2006**	2005	**2006**	2005
Change in Benefit Obligation				
Benefit obligation – beginning of year	**679**	45	**81**	2
Current service cost	**24**	4	**7**	1
Interest cost	**37**	7	**5**	1
Employee contributions	**5**	–	**–**	–
Benefits paid	**(15)**	(3)	**(2)**	–
Actuarial loss	**77**	17	**72**	2
Foreign exchange rate changes	**–**	(1)	**–**	–
Bruce B[(1)]	**–**	610	**–**	75
Plan amendment	**–**	–	**6**	–
Benefit obligation – end of year	**807**	679	**169**	81
Change in Plan Assets				
Plan assets at fair value – beginning of year	**585**	57	**–**	–
Actual return on plan assets	**68**	18	**–**	–
Employer contributions	**23**	4	**2**	–
Employee contributions	**5**	–	**–**	–
Benefits paid	**(15)**	(3)	**(2)**	–
Foreign exchange rate changes	**–**	(1)	**–**	–
Bruce B[(1)]	**–**	510	**–**	–
Plan assets at fair value – end of year	**666**	585	**–**	–
Funded status – plan deficit	**(141)**	(94)	**(169)**	(81)
Unamortized net actuarial loss/(gain)	**174**	125	**66**	(5)
Unamortized past service costs	**–**	1	**6**	–
Accrued benefit asset/(liability), net of valuation allowance of nil	**33**	32	**(97)**	(86)

(1) The Company proportionately consolidated Bruce B, on a prospective basis at 31.6 per cent, effective October 31, 2005.

The accrued benefit asset/(liability), net of valuation allowance of nil, is included in the Company's balance sheet as follows.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2006**	2005	**2006**	2005
Other assets	**33**	32	**–**	–
Deferred amounts	**–**	–	**(97)**	(86)
Total	**33**	32	**(97)**	(86)

Included in the above benefit obligation and fair value of plan assets at December 31 are the following amounts in respect of plans that are not fully funded.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2006**	2005	**2006**	2005
Benefit obligation	**(773)**	(645)	**(169)**	(81)
Plan assets at fair value	**609**	534	**–**	–
Funded status – plan deficit	**(164)**	(111)	**(169)**	(81)

The Company's joint ventures' expected contributions for the year ended December 31, 2007 are approximately $33 million for the pension benefit plans and approximately $3 million for the other benefit plans.

The following are estimated future benefit payments, which reflect expected future service.

(millions of dollars)	Pension Benefits	Other Benefits
2007	13	3
2008	15	4
2009	19	4
2010	23	5
2011	27	6
Years 2012 to 2016	194	40

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

	Pension Benefit Plans		Other Benefit Plans	
	2006	2005	**2006**	2005
Discount rate	**5.05%**	5.30%	**4.95%**	5.15%
Rate of compensation increase	**3.50%**	3.50%		

The significant weighted average actuarial assumptions adopted in measuring the Company's joint ventures' net benefit plan cost for years ended December 31 are as follows.

	Pension Benefit Plans			Other Benefit Plans		
	2006	2005	2004	**2006**	2005	2004
Discount rate	**5.25%**	6.20%	6.00%	**5.15%**	6.25%	6.00%
Expected long-term rate of return on plan assets	**7.30%**	7.40%	8.50%			
Rate of compensation increase	**3.50%**	3.50%	4.00%			

A one percentage point increase or decrease in assumed health care cost trend rates would have the following effects.

(millions of dollars)	Increase	Decrease
Effect on total of service and interest cost components	2	(1)
Effect on post-employment benefit obligation	24	(20)

The Company's proportionate share of net benefit cost of joint ventures is as follows.

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31 (millions of dollars)	**2006**	2005	2004	**2006**	2005	2004
Current service cost	**24**	4	1	**7**	1	–
Interest cost	**37**	7	3	**5**	1	–
Actual return on plan assets	**(68)**	(18)	(7)	**–**	–	–
Actuarial loss	**77**	17	–	**72**	2	–
Plan amendment	**–**	–	–	**6**	–	–
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**70**	10	(3)	**90**	4	–
Difference between expected and actual return on plan assets	**26**	9	2	**–**	–	–
Difference between actuarial loss recognized and actual actuarial loss on accrued benefit obligation	**(70)**	(16)	1	**(72)**	(3)	–
Difference between amortization of past service costs and actual plan amendments	**–**	–	–	**(6)**	–	–
Net benefit cost recognized related to joint ventures	**26**	3	–	**12**	1	–

The Company's joint ventures' pension plans' weighted average asset allocations and weighted average target allocation at December 31, by asset category, are as follows.

	Percentage of Plan Assets		**Target Allocation**
Asset Category	**2006**	2005	**2006**
Debt securities	**29%**	30%	**30%**
Equity securities	**71%**	70%	**70%**
	100%	100%	

Debt securities include the Company's debt in the amount 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, 2006 and 2005, respectively. Equity securities include the Company's common shares in the amounts of $6 million (1 per cent of total plan assets) and $5 million (0.9 per cent of total plan assets) at December 31, 2006 and 2005, 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 20 CHANGES IN OPERATING WORKING CAPITAL

Year ended December 31 (millions of dollars)	**2006**	2005	2004
(Increase)/decrease in accounts receivable	**(188)**	(100)	16
Increase in inventories	**(108)**	(50)	–
(Increase)/decrease in other current assets	**(6)**	(1)	24
(Decrease)/increase in accounts payable	**(42)**	97	(4)
Increase/(decrease) in accrued interest	**41**	5	(7)
	(303)	(49)	29

NOTE 21 COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

Operating leases
Future annual payments, net of sub-lease receipts, under the Company's operating leases for various premises, services, equipment and a natural gas storage facility are approximately as follows.

Year ended December 31 (millions of dollars)	Minimum Lease Payments	Amounts Recoverable under Sub-Leases	Net Payments
2007	52	(13)	39
2008	54	(13)	41
2009	54	(12)	42
2010	53	(12)	41
2011	55	(12)	43
2012 and thereafter	731	(18)	713
Total	999	(80)	919

The operating lease agreements for premises, services and equipment expire at various dates through 2016, with an option to renew certain lease agreements for three to five years. The operating lease agreement for the natural gas storage facility expires in 2030 with lessee termination rights every fifth anniversary commencing in 2010 and with the lessor having the right to terminate the agreement every five years commencing in 2015. Net rental expense on operating leases for the year ended December 31, 2006 was $25 million (2005 – $17 million; 2004 – $7 million).

Bruce Power
TransCanada's share of Bruce A's signed commitments to third party suppliers for the next four years for the restart and refurbishment of the currently idle Units 1 and 2, extending the operating life of Unit 3 by replacing its steam generators and fuel channels when required, and replacing the steam generators on Unit 4, is as follows.

Year ended December 31 (millions of dollars)	
2007	450
2008	164
2009	71
2010	1
2011	–
	686

In addition to these capital commitments, the Company is committed to capital expenditures of approximately $1.2 billion for the construction of its Halton Hills, Portlands Energy and remaining Cartier Wind projects.

TransCanada has guaranteed the performance of all obligations of PipeLines LP with respect to its acquisition of a 46.45 per cent interest in Great Lakes pursuant to the purchase agreement.

Aboriginal Pipeline Group
On June 18, 2003, the Mackenzie Delta gas producers, the APG and TransCanada reached an agreement which governs TransCanada's role in the MGP Project. The project would result in a natural gas pipeline being constructed from Inuvik, Northwest Territories, to the northern border of Alberta, where it would connect with the Alberta System. Under the agreement, TransCanada agreed to finance the APG for its one-third share of project development costs. These costs are currently forecasted to be approximately $145 million by the end of 2007.

Contingencies

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

The Company and its subsidiaries are subject to various other 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

The Company, together with Cameco Corporation and BPC Generation Infrastructure Trust (BPC), has severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, operator licenses, the lease agreement and contractor services. The terms of the guarantees range from 2007 to 2018.

As part of the reorganization of Bruce Power in 2005, including the formation of Bruce A and the commitment to restart and refurbish the Bruce A units, the Company, together with BPC, severally guaranteed one-half of certain contingent financial obligations of Bruce A related to the refurbishment agreement with the Ontario Power Authority and cost sharing and sublease agreements with Bruce B. The terms of the guarantees range from 2019 to 2036.

TransCanada's share of the exposure under these Bruce Power guarantees at December 31, 2006 was estimated to be approximately $586 million to a calculated maximum of $658 million. The current carrying amount of the liability related to these guarantees is nil and the fair value is approximately $17 million.

TransCanada has guaranteed the equity undertaking of a subsidiary which supports the payment, under certain conditions, of principal and interest on US$105 million of public debt obligations of TransGas. The Company has a 46.5 per cent interest in TransGas. Under the terms of the agreement, the Company severally with another major multinational company may be required to fund more than their proportionate share of debt obligations of TransGas in the event that the minority shareholders fail to contribute. Any payments made by TransCanada under this agreement convert into share capital of TransGas. The potential exposure is contingent on the impact of any change of law on TransGas' ability to service the debt. From the issuance of the debt in 1995 to date, there has been no change in applicable law and thus no exposure to TransCanada. The debt matures in 2010. The Company has made no provision related to this guarantee.

In connection with the acquisition of GTN, US$241 million of the purchase price was deposited into an escrow account. At December 31, 2006, there was US$24 million remaining in the escrow account which represented the full face amount of the potential liability under certain GTN guarantees. In February 2007, the funds were released and a portion of the monies were used to satisfy the liability of GTN under these designated guarantees.

NOTE 22 DISCONTINUED OPERATIONS

TransCanada's net income for the year ended December 31, 2006 includes $28 million or $0.06 per share of net income from discontinued operations reflecting settlements received from bankruptcy claims related to TransCanada's Gas Marketing business divested in 2001 (2005 – nil; 2004 – $52 million, net of $27 million of income taxes).

NOTE 23 SUBSEQUENT EVENTS

ANR Acquisition

On February 22, 2007, TransCanada closed the acquisition of the American Natural Resources Company and the ANR Storage Company (together ANR), and an additional 3.55 per cent interest in Great Lakes from El Paso Corporation for approximately US$3.4 billion, subject to certain post-closing adjustments, including approximately US$488 million of assumed long-term debt. The acquisition was financed with a combination of proceeds from the Company's recent equity offering, cash on hand and funds drawn on existing and newly established loan facilities, discussed below.

In January 2007, TransCanada filed a final short form shelf prospectus with securities regulators in Canada and the U.S. to allow for the offering of up to $3.0 billion of common shares, preferred shares and/or subscription receipts in Canada and the U.S. until February 2009. The nature, size and timing of any financings will be dependent on TransCanada's assessment of its requirements for funding and general market conditions.

On February 6, 2007, TransCanada entered into an agreement with a syndicate of underwriters under which the underwriters agreed to purchase 39,470,000 subscription receipts from TransCanada and sell them to the public at a price of $38.00 each. The offering closed on February 14, 2007, resulting in gross proceeds to TransCanada of approximately $1.5 billion which were used towards financing the acquisition of ANR. TransCanada also granted the underwriters of the subscription receipts offering an option to purchase an additional 5,920,500 common shares at $38.00 per common share at any time up to and including March 16, 2007. Upon closing of the ANR acquisition, the subscription receipts were exchanged on a one-to-one basis for common shares of TransCanada without any further action of, or payment from, the holder. At February 22, 2007, the Company had 528.7 million issued and outstanding common shares.

In February 2007, the Company executed an agreement with a syndicate of banks for a US$2.2 billion, one-year bridge loan facility. The facility is committed and unsecured. The Company utilized $1.5 billion and US$700 million from this facility to partially finance the ANR acquisition, of which $1.5 billion and US$20 million were subsequently repaid from the proceeds of the $1.5 billion subscription receipts offering and cash on hand, respectively.

In February 2007, the Company, through a wholly owned subsidiary, executed an agreement with a syndicate of banks to establish a new US$1.0 billion credit facility, consisting of a US$700 million five-year term loan and a US$300 million five-year extendible revolving facility. This facility is committed and unsecured. 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 as well as additional investments in PipeLines LP, described below.

Great Lakes Acquisition

On February 22, 2007, PipeLines LP closed its acquisition of a 46.45 per cent interest in Great Lakes from El Paso Corporation for approximately US$962 million, which included approximately US$212 million of assumed long-term debt, subject to certain post-closing adjustments. At December 31, 2006, TransCanada had a 13.4 per cent interest in PipeLines LP.

In February 2007, PipeLines LP increased the size of its syndicated revolving credit and term loan agreement from US$410 million to US$950 million. Incremental draws of US$126 million received under this agreement were used to partially finance PipeLines LP's Great Lakes acquisition.

On February 22, 2007, PipeLines LP completed a private placement offering of 17,356,086 common units at a price of US$34.57 per unit, of which 50 per cent of the units were acquired by TransCanada, for US$300 million. TransCanada also invested an additional approximately US$12 million to maintain its general partnership interest in PipeLines LP. As a result of TransCanada's additional investments in PipeLines LP, its ownership in PipeLines LP increased to 32.1 per cent. The total private placement resulted in gross proceeds to PipeLines LP of approximately US$612 million, which were used to partially finance its Great Lakes acquisition. As a result of TransCanada's increased ownership in PipeLines LP, TransCanada's effective ownership in Tuscarora, Northern Border and Great Lakes increased to 32.5 per cent (including one per cent held directly), 16.1 per cent and 68.5 per cent, respectively.