MANAGEMENT'S DISCUSSION AND ANALYSIS

CONSOLIDATED FINANCIAL REVIEW

The Management's Discussion and Analysis dated March 1, 2005 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, 2004. Amounts are stated in Canadian dollars unless otherwise indicated.

HIGHLIGHTS

Net Income In 2004, net income was $1.032 billion or $2.13 per share compared to $851 million or $1.76 per share in 2003.

Net Earnings In 2004, TransCanada's net income from continuing operations (net earnings) increased $179 million to $980 million or $2.02 per share compared to $801 million or $1.66 per share in 2003.

Investing Activities In 2004, TransCanada invested more than $2.6 billion (including assumed debt), in the Gas Transmission and Power businesses. Approximately $2.1 billion was invested in the acquisition of the Gas Transmission Northwest System and the North Baja System (collectively GTN).

Balance Sheet In 2004, TransCanada's shareholders' equity increased by approximately $0.5 billion.

Dividend On February 1, 2005, the Board of Directors of TransCanada raised the quarterly dividend on the company's outstanding common shares 5.2 per cent to $0.305 per share from $0.29 per share for the quarter ending March 31, 2005.

Consolidated Results-at-a-Glance

Year ended December 31 (millions of dollars except per share amounts)	**2004**	2003	2002
Net Income			
Continuing operations*	**980**	801	747
Discontinued operations	**52**	50	–
	1,032	851	747
Net Income Per Share – Basic			
Continuing operations*	**$ 2.02**	$ 1.66	$ 1.56
Discontinued operations	**0.11**	0.10	–
	$ 2.13	$ 1.76	$ 1.56

Segment Results-at-a-Glance

Year ended December 31 (millions of dollars)	**2004**	2003	2002
Gas Transmission	**586**	622	653
Power	**396**	220	146
Corporate	**(2)**	(41)	(52)
Continuing operations*	**980**	801	747
Discontinued operations	**52**	50	–
Net income	**1,032**	851	747

* Net earnings.

Net income for the year ended December 31, 2004 was $1.032 billion or $2.13 per share compared to $851 million or $1.76 per share for 2003. This includes net income from discontinued operations of $52 million or $0.11 per share in 2004 and $50 million or $0.10 per share in 2003, reflecting income recognized on the initially deferred gains relating to the disposition in 2001 of the company's Gas Marketing business. Net income in 2002 was $747 million or $1.56 per share.

TransCanada's net earnings for the year ended December 31, 2004 were $980 million or $2.02 per share compared to $801 million or $1.66 per share in 2003 and $747 million or $1.56 per share in 2002. The increase of $179 million or $0.36 per share in 2004 compared to 2003 was primarily due to significantly higher net earnings from the Power business. In addition, lower net earnings from the Gas Transmission business were offset by reduced net expenses in the Corporate segment.

Net earnings from the Power business increased $176 million in 2004 compared to 2003 primarily due to the realization in 2004 of a gain of $15 million after tax ($25 million pre tax) or $0.03 per share on the sale of the ManChief and Curtis Palmer power plants to TransCanada Power, L.P. (Power LP) and the recognition of $172 million or $0.36 per share of dilution and other gains resulting from a reduction in TransCanada's ownership interest in Power LP and the removal of Power LP's obligation, in 2017, to redeem units not owned by TransCanada. TransCanada was previously required to fund this redemption, therefore, the removal of Power LP's obligation eliminates this requirement.

Excluding the above-mentioned $187 million of combined gains included in net earnings related to Power LP and the recognition in 2003 of a $19 million after-tax settlement with a former counterparty, Power's net earnings in 2004 were $8 million higher than in 2003. Higher equity income from TransCanada's investment in Bruce Power L.P. (Bruce Power), acquired in February 2003, was partially offset by lower contributions from Eastern Operations and TransCanada's investment in Power LP.

The decrease in net earnings of $36 million in the Gas Transmission business in 2004 compared to 2003 were primarily due to a decline in the Alberta System's and Canadian Mainline's net earnings. The Alberta System's net earnings in 2004 reflect the impacts of the Alberta Energy and Utilities Board (EUB) decisions in 2004 on Phase I of the General Rate Application (GRA) and Generic Cost of Capital (GCOC). The decline in the Canadian Mainline's net earnings was primarily as a result of a lower rate of return on common equity (ROE) as determined by the generic ROE formula set by the National Energy Board (NEB) and a lower average investment base. These decreases were partially offset by net earnings from GTN, which TransCanada acquired on November 1, 2004, higher earnings from CrossAlta Gas Storage & Services Ltd. (CrossAlta) and TransCanada Pipeline Ventures Limited Partnership (Ventures LP), and a $7 million gain on sale of the company's equity interest in the Millennium Pipeline project (Millennium). The 2003 results included TransCanada's $11 million share of a positive future income tax benefit adjustment recognized by TransGas de Occidente S.A. (TransGas).

The decrease in net expenses of $39 million in the Corporate segment in 2004 was primarily due to the positive impacts of income tax and foreign exchange related items throughout 2004 and the release in 2004 of previously established restructuring provisions.

The increase of $54 million or $0.10 per share in 2003 net earnings compared to 2002 was mainly due to higher net earnings from the Power business and reduced net expenses in the Corporate segment, partially offset by lower net earnings from the Gas Transmission business. Net earnings from the Power business in 2003 included equity income of $73 million after tax from TransCanada's investment in Bruce Power and a $19 million after-tax settlement with a former counterparty. The reduction in net earnings in the Gas Transmission business in 2003 compared to 2002 reflects a decline in the Canadian Mainline and the Alberta System's net earnings. The 2002 results included TransCanada's $7 million share of a favourable ruling for Great Lakes Gas Transmission Limited Partnership related to Minnesota use tax paid in prior years.

Pursuant to a plan of arrangement, effective May 15, 2003, common shares of TransCanada PipeLines Limited (TCPL) were exchanged on a one-to-one basis for common shares of TransCanada. As a result, TCPL became a wholly-owned subsidiary of TransCanada. The consolidated financial statements for the years ended December 31, 2004 and 2003 include the accounts of TransCanada, the consolidated accounts of all subsidiaries, including TCPL, and TransCanada's proportionate share of the accounts of the company's joint venture investments. Comparative information for the year ended December 31, 2002 is that of TCPL, its subsidiaries, and its proportionate share of the accounts of its joint venture investments at that time.

TRANSCANADA OVERVIEW

TransCanada is a leading North American energy company focused on natural gas transmission and power generation and marketing opportunities in regions where it enjoys 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 use similar technology and operating practices. They are businesses with significant long-term growth prospects.

North American natural gas demand is growing and that demand is mainly driven by the 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 through higher utilization of new gas-fired generating plants that were built as part of the massive capacity additions that occurred in many North American markets over the last five years.

Coal-fired plants are still the largest source of electric power in North America and coal reserves are significant. Nuclear facilities have also played a significant role in supplying North America with power in the past and new nuclear capacity will likely come on stream over time.

However, the long lead times required to complete new coal and nuclear projects, the associated environmental and public relations issues, the high capital costs and the difficulty in locating these plants near load centres 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. Overall, North American natural gas demand is expected to grow to 85 billion cubic feet per day (Bcf/d) by 2015, an increase of 15 Bcf/d when compared to 2004. New natural gas-fired power generation is expected to account for approximately 10 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. Current high natural gas prices are clear evidence that North America is in a period of transition and significant change. Natural gas supply is tight 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 remain flat over the next decade. An increase in production in the United States Rockies will likely only offset declines in other basins, including the Gulf of Mexico. This outlook for traditional basins means that northern gas and offshore liquefied natural gas (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 new natural gas supply to market in the medium to longer 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 five years ago. 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 five components:

- Grow the North American Gas Transmission business.
- Maximize the long-term value of the Canadian wholly-owned Gas Transmission business.
- Grow the North American Power business.
- Drive for operational excellence.
- Maximize the corporate strength and value of TransCanada.

GAS TRANSMISSION

TransCanada's natural gas transmission assets link the Western Canada Sedimentary Basin (WCSB) with premium North American markets. With more than 41,000 kilometres (km) of pipeline, the company's network of wholly-owned pipeline assets is one of the largest in North America.

In 2004, the wholly-owned Alberta System gathered 64 per cent of the natural gas produced in Western Canada or 16 per cent of total North American production. TransCanada exports gas from the WCSB to Eastern Canada and the U.S. West, Midwest and Northeast through four wholly-owned systems – the Canadian Mainline, the Gas Transmission Northwest System, the Foothills System and the BC System – and six partially-owned systems – Trans Québec & Maritimes System (TQM), Great Lakes Gas Transmission System (Great Lakes), Iroquois Gas Transmission System (Iroquois), Portland Natural Gas Transmission System (Portland), Northern Border Pipeline (Northern Border) and Tuscarora Gas Transmission System (Tuscarora). The company's strategy in Gas Transmission is focused on both growing its North American natural gas transmission network and maximizing the long-term value of its Canadian wholly-owned pipelines. In order to grow the Gas Transmission business, TransCanada is focusing its efforts on expanding and extending its existing systems to connect new supply to growing markets, increasing its ownership in partially-owned entities, acquiring other pipelines that provide it with a significant regional presence and in the long term, connecting new sources of supply in the form of northern gas and LNG.

The company's ability to successfully execute its strategy has been and continues to be directly related to the core competencies that have been developed in Gas Transmission.

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. TransCanada also has strong project development and management skills and is committed as an organization to the highest levels of operational excellence. The company's strong financial position allows it to build large-scale infrastructure and act quickly on quality opportunities as they arise.

Significant milestones were achieved in the Gas Transmission business in 2004. The acquisition of GTN is a prime example. The Gas Transmission Northwest System consists of 2,174 km of pipeline extending from Kingsgate, British Columbia on the B.C./Idaho border to Malin, Oregon on the Oregon/California border. It interconnects with the BC System and Foothills System and transports WCSB natural gas to growing markets in the Pacific Northwest, California and Nevada. The North Baja System is a 128 km system that extends from Ehrenberg, Arizona to a point near Ogilby, California on the California/Mexico border. In the future, this line could be modified at relatively low cost to allow natural gas to flow from LNG terminals in Baja, Mexico to markets in the U.S.

Looking north, TransCanada has secured a position in the Mackenzie Gas Pipeline Project and, in Alaska, it has assembled significant legal, technical and environmental information. Foothills Pipe Lines Ltd. (Foothills) was granted certificates for the Canadian portion of the Alaska Highway Pipeline Project over 25 years ago. Certificates of Public Convenience and Necessity were granted to Foothills under the Northern Pipeline Act of Canada (NPA). 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 NPA, following a lengthy competitive hearing before the NEB in the late 1970's, 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 the facilities in Alberta 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.

During 2004, to continue to move the Alaska Highway Pipeline Project forward, the company filed an application under the State of Alaska's Stranded Gas Development Act, which is the State's vehicle for dealing with fiscal concessions and other matters related to this project. TransCanada's application is one of three applications currently before the State. As well, TransCanada requested the State to resume processing its long-pending application for a right-of-way lease on State lands. TransCanada holds the complementary rights-of-way on federal lands in Alaska. In addition, the company continued discussions with a number of parties, including Alaska North Slope producers, the State of Alaska, the government of Canada and key players in the North American natural gas market.

If the Mackenzie Gas Pipeline 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 of the company's existing Gas Transmission business, especially the Canadian wholly-owned pipelines.

In 2004, TransCanada also took steps to advance a number of LNG projects. TransCanada is of the view that LNG will play a significant role in meeting growing North American gas demand. Based on North American natural gas prices, the company believes that Eastern Canada and the Northeast U.S., where natural gas sells at a premium, are logical locations to import LNG. TransCanada is currently assessing a number of long-term opportunities in these regions including the Cacouna Energy Project in Québec and the Broadwater Energy Project in New York. In general, LNG projects may experience siting challenges.

TransCanada's focus on these projects is on the regasification terminal and related pipeline infrastructure that complements and supports the company's existing pipeline investments.

The company's initiatives in the natural gas storage business are a logical extension of its Gas Transmission business. TransCanada believes Alberta-based natural gas storage will continue to serve market needs and could play an important role should northern gas be connected to North American markets. In January 2005, TransCanada announced plans to develop a natural gas storage facility near Edson, Alberta. The Edson facility will have a capacity of approximately 50 Bcf and connect to TransCanada's Alberta System. In addition, in 2004, the company secured a long-term contract with a third party for existing Alberta-based natural gas storage capacity, ramping up from approximately 20 Bcf in 2005 to 30 Bcf in 2006 and to 40 Bcf in 2007. These initiatives, combined with the company's current 60 per cent ownership interest in CrossAlta, position TransCanada to become one of the largest natural gas storage providers in Western Canada with 110 Bcf of storage capacity by 2007 which will represent approximately one-third of the natural gas storage capacity available in Alberta.

In addition to growing the North American Gas Transmission business, the company continues to place a strategic priority on maximizing the long-term value of its Canadian 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 continues to respond to changes in the market by introducing new services to meet customer needs.

In 2004, TransCanada received a number of regulatory decisions from the NEB and the EUB with mixed results. TransCanada was generally pleased with the NEB's decision on the 2004 Canadian Mainline Tolls and Tariff Application (2004 Application) Phase I and its decision to approve North Bay Junction (NBJ) as a new receipt and delivery point, which TransCanada views as forward steps in ensuring the long-term sustainability of the Canadian Mainline to the benefit of all stakeholders. However, two decisions from the EUB in 2004 related to the Alberta System were disappointing.

In July 2004, the EUB released its decision in the GCOC proceeding. All Alberta provincially regulated utilities, including the Alberta System, were mandated an ROE of 9.60 per cent for 2004. This generic ROE will be adjusted annually by 75 per cent of the change in long-term Government of Canada bonds from the previous year, consistent with the approach used by the NEB. The EUB also established a deemed common equity of 35 per cent for the Alberta System. This result was significantly less than the applied for ROE of 11 per cent on deemed common equity of 40 per cent, which the company considered to be a fair return.

In September 2003, TransCanada filed Phase I of the 2004 GRA with the EUB, consisting of evidence in support of the applied-for rate base and revenue requirement. In its August 24, 2004 decision, the EUB approved the purchase of the Simmons Pipeline System (Simmons) for approximately $22 million and the costs of firm transportation (FT) service arrangements with the Foothills, Simmons and Ventures LP systems. However, a significant amount of costs were disallowed for recovery, which reduced revenue requirement and rate base.

In September 2004, TransCanada filed with the Alberta Court of Appeal for leave to appeal the EUB's decision on Phase I of the 2004 GRA with respect to the disallowance of applied-for incentive compensation costs. In its decision, the EUB disallowed approximately $24 million (pre tax) of operating costs, which included $19 million of applied-for incentive compensation costs. TransCanada believes the EUB made errors of law in deciding to deny the inclusion of these compensation-related costs in the revenue requirement. The company believes these are necessary costs that it reasonably and prudently incurs for the safe, reliable and efficient operation of the Alberta System. At the request of TransCanada, the Alberta Court of Appeal adjourned the appeal for an indefinite period of time while TransCanada considers the merits of a review and variance application to the EUB in respect of 2004 costs. On February 24, 2005, TransCanada advised the EUB that an agreement in principle had been reached with negotiating parties on a revenue requirement settlement for the period January 1, 2005 to December 31, 2007. The agreement is subject to formal approval by participating parties, and ultimately by the EUB.

In 2004, TransCanada applied for an allowed return for the Canadian Mainline based on the NEB's ROE formula on a 40 per cent deemed common equity. An NEB decision is expected in second quarter 2005.

On February 14, 2005, TransCanada announced it had reached a settlement with its Canadian Mainline shippers regarding 2005 tolls. This settlement establishes operating, maintenance and administration (OM&A) costs for 2005 at $169.5 million, which is comparable to the 2004 level. Any variance between actual OM&A costs in 2005 and those agreed to in the settlement will accrue to TransCanada. All other cost elements of the 2005 revenue requirement will be treated on a flow through basis. Further, the 2005 ROE for the Canadian Mainline will be 9.46 per cent as determined under the NEB formula, and the common equity component of the Canadian Mainline's capital structure for 2005 shall be based on the NEB's decision in the recently concluded hearing on the Canadian Mainline's cost of capital for 2004, subject to the outcome of any review applications or appeals.

In February 2005, TransCanada announced that it is proposing a US$1.7 billion oil pipeline project to transport approximately 400,000 barrels per day of heavy crude oil from Alberta to Illinois. The proposed Keystone Pipeline (Keystone) would be approximately 3,000 km in length. In addition to new pipeline construction, Keystone would require the conversion of approximately 1,240 km of one of the lines in TransCanada's existing multi-line natural gas pipeline systems in Alberta, Saskatchewan and Manitoba.

TransCanada will continue to meet with oil producers, refiners and industry groups, including the Canadian Association of Petroleum Producers, to gauge additional interest and support for Keystone. Preliminary discussions have begun with stakeholders, including communities, government representatives and landowners along the proposed route. TransCanada will proceed with the necessary regulatory applications when sufficient support for this project from oil producers and shippers is obtained.

TransCanada will require various regulatory approvals from Canadian and U.S. agencies before construction can begin. Input from all stakeholders will be received through the regulatory process and an extensive public consultation process.

TransCanada is in the business of connecting energy supplies to markets and it views this 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.

POWER

TransCanada has built a substantial power business over the last ten years. Currently, the power plants and power supply that TransCanada owns, operates and/or controls, including those under construction or in development, in the aggregate, represent approximately 5,700 megawatts (MW) of power generation capacity in Canada and the U.S. The company's physical assets are concentrated in two main regions – one in the west, the other in the east. The western business is focused in Alberta where TransCanada is one of the largest providers of wholesale power in the province. Assets include five gas-fired cogeneration plants and power purchase arrangements (PPAs) at the Sundance A and B coal-fired plants. In the east, the focus has been on the Ontario, Québec, New England and New York markets. The company started with a minority interest in Ocean State Power (OSP), a 560 MW gas-fired plant in Rhode Island. In Ontario, TransCanada began by developing three natural gas-fired plants adjacent to compressor stations along the Canadian Mainline. Today, through its investments, TransCanada is the largest private sector generator in Ontario.

TransCanada's strategy for growth and value creation in Power has been driven by four main principles.

First, the company has focused its efforts on acquiring low-cost, base-load generation in markets it knows. PPA entitlements at the Sundance A and B coal-fired plants in Alberta, its investment in Bruce Power and the pending acquisition of USGen New England (USGen) are prime examples of this approach. The company believes that being a low-cost provider and/or having long-term power sales contracts is critical to being successful in the power business.

Second, TransCanada has focused on developing low-risk, greenfield, gas-fired cogeneration projects. Although higher on the cost curve than hydro, nuclear or coal, they are much more efficient than various other forms of generation including combined-cycle gas-fired plants. To reduce the risk associated with these higher cost sources of production, TransCanada has focused on selling a significant portion of the output from these plants to strong counterparties under long-term contracts where the buyer also assumes the risk associated with fluctuations in the natural gas price. The Grandview and Bécancour projects are examples of this approach.

Third, TransCanada actively participates in markets that are in transition. The changes that took place in New England and Alberta, and the changes that continue in Ontario, allow the company to capture opportunities that are created as a result of markets in transition.

Lastly, TransCanada has focused its attention on optimizing its existing asset portfolio by running the company's facilities as efficiently and cost-effectively as possible through its drive for operational excellence.

TransCanada's ability to successfully execute its strategy is directly related to the core competencies that it has developed in the power business. Over the years, the company has gained 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. It has been an active participant in deregulated markets. The experience gained in its core markets serves the company well as it pursues opportunities in those and other areas. TransCanada uses its ability to structure deals and manage risk which is critical to mitigating volatility and uncertainty for its industrial customers and its shareholders. TransCanada's financial position allows it to build large-scale infrastructure and gives it the ability to act quickly on quality opportunities as they arise. The company has strong project development skills and is committed as an organization to operational excellence.

In 2004, TransCanada continued to add to its diverse portfolio of quality power generation assets.

In addition to the completion of the restart of Unit 3 at Bruce Power and the commissioning of the MacKay River cogeneration plant in 2004, the company also completed construction of the Grandview facility, a 90 MW natural gas-fired cogeneration power plant located in Saint John, New Brunswick. All of the power and heat output from the Grandview plant will be sold to Irving Oil Limited under a 20 year PPA. The company also continued to make progress on the new 550 MW Bécancour natural gas-fired cogeneration plant, which is located near Trois-Rivières, Québec. All of the power output from that plant will be sold under a 20 year PPA to Hydro-Québec Distribution (Hydro-Québec). Final approvals for this project were received in July 2004 and construction has commenced. It is scheduled to be in-service in late 2006.

In October 2004, TransCanada announced that Cartier Wind Energy (Cartier Wind), owned 62 per cent by TransCanada, was awarded six projects by Hydro-Québec representing a total of 739.5 MW. Long-term electricity supply contracts were signed with Hydro-Québec on February 25, 2005 for each of the facilities. The six projects are expected to be commissioned between 2006 and 2012 at an estimated total capital cost of more than $1.1 billion.

In December 2004, TransCanada announced it would proceed with the purchase of hydroelectric generation assets with a total generating capacity of 567 MW from USGen for US$505 million. The assets include generating assets on two river systems in New England. The purchase is subject to the sale of the 49 MW Bellows Falls hydroelectric facility to the Vermont Hydroelectric Power Authority (Vermont Hydroelectric), which has exercised its pre-existing option to purchase this plant. This would result in a US$72 million reduction in the purchase price to US$433 million for 518 MW.

TransCanada is well positioned to play a role in helping Ontario meet its future energy needs. The Ontario government has estimated that $25 billion to $40 billion of capital investment will be required to refurbish, rebuild, replace or conserve 25,000 MW of generating capacity by 2020. Bruce Power, 31.6 per cent owned by TransCanada, continues to evaluate the feasibility of restarting Units 1 and 2 and talks between Bruce Power and a provincially appointed negotiator regarding the potential restart of the two 750 MW units are ongoing. TransCanada also submitted proposals to the Ontario government under its recent request-for-proposal process that seeks up to 2,500 MW of new electricity generation capacity and/or conservation measures. This power is expected to come on-line between 2005 and 2009.

TransCanada, together with its Bruce Power partners, is also evaluating a potential investment in the refurbishment of the 680 MW Point Lepreau nuclear generating station in New Brunswick. Discussions are currently ongoing with New Brunswick Power.

TransCanada expects its Power business to continue to be a key growth driver in the years ahead. The company is committed to growing the Power business through asset acquisitions, selected greenfield developments and further expansions of its existing business and footprint. The goal is to build and establish a diverse portfolio of high quality assets that deliver strong returns to TransCanada's shareholders.

OPERATIONAL EXCELLENCE AND "SPIRIT"

In addition to growing its Gas Transmission and Power businesses, TransCanada is committed to an operational excellence business model. Its focus is on being a cost-conscious, reliable and safe operator, providing desired services to its customers in an effective and timely manner. The company's values guide the way business is conducted at TransCanada. Within TransCanada, these values are commonly referred to as "SPIRIT". They are the principles that direct how the company works and they include – Social responsibility, Passion, Integrity, Results, Innovation and Teamwork. The company's commitment to these values helps ensure it maintains its reputation as one of North America's premier energy companies.

TransCanada has approximately 2,450 employees who through their talent, hard work and results provide the company a strong competitive advantage because of their industry-leading expertise in pipeline and power operations, project management, depth of market and industry knowledge, and financial acumen.

OUTLOOK

In 2005, TransCanada will continue to execute its corporate strategy in a disciplined and focused manner by directing its energies towards long-term growth opportunities that will strengthen its financial performance and create long-term value for shareholders. The company's net earnings and cash flow combined with a strong balance sheet continue to provide the financial flexibility for TransCanada to make disciplined investments in its core businesses of Gas Transmission and Power.

In Gas Transmission, the company will continue to focus its efforts on expanding and extending its existing systems to connect new supply to growing markets, increasing its ownership in partially-owned entities, acquiring other pipelines that provide it with a significant regional presence and connecting new sources of supply in the form of northern gas and LNG. The company will also focus on maximizing the long-term value of its Canadian wholly-owned natural gas pipelines.

In 2005, there will be a full year's contribution from GTN, which was acquired on November 1, 2004. The company expects lower allowed ROEs and lower average investment bases for both the Canadian Mainline and the Alberta System. The outcome of customer settlement negotiations and regulatory proceedings could have a significant positive or negative impact on earnings from the Gas Transmission segment in 2005.

In the Power business, the company will continue to focus on acquiring low-cost, base-load generation, developing low-risk greenfield cogeneration projects, capitalizing on opportunities in markets that are in transition and optimizing its existing asset portfolio.

The potential variability in Bruce Power's earnings caused by changes in prices realized, operating expenses, and plant availability, and the outcome of a fourth arbitration related to the cost of fuel gas for OSP expected by the end of third quarter 2005 could impact earnings in 2005.

A $1.00 per megawatt hour (MWh) change in the spot price for electricity in Ontario would change TransCanada's after-tax equity income from Bruce Power by approximately $5 million. Bruce Power operating expenses are expected to increase in 2005 due to higher outage costs, higher depreciation on the Bruce A units and recent capital programs and higher fuel costs. The average availability in 2005 for Bruce Power is expected to be 85 per cent compared to 82 per cent in 2004.

In 2004, as a result of a third arbitration process, OSP's cost of fuel gas was substantially increased to a price in excess of market. Should a fourth arbitration decision at OSP, expected in 2005, continue to support a pricing mechanism for fuel gas in excess of market price and if anticipated market conditions do not change substantially, management expects there could be an asset impairment write-down of this facility. The net carrying value of OSP at December 31, 2004 was approximately US$150 million.

The sale of the Curtis Palmer and ManChief plants in April 2004 results in the loss of earnings from these plants for a full year in 2005. The Grandview cogeneration plant and the proposed acquisition of the USGen assets are expected to have a positive impact on 2005 earnings from the Power segment. In addition, plant availability, fluctuating market prices, weather and regulatory decisions could impact earnings.

In 2004, income tax and foreign exchange related items and the release of a previously established restructuring provision had a significantly positive impact on the results of the Corporate segment. In 2005, the Corporate segment is expected to incur a more normalized level of net expenses with higher net expenses than in 2004.

GAS TRANSMISSION

HIGHLIGHTS

Net Earnings Net earnings from Gas Transmission decreased $36 million to $586 million in 2004 compared to $622 million in 2003.

This decrease is primarily due to a $40 million decrease from the Alberta System and an $18 million decrease from the Canadian Mainline offset by a $14 million increase due to the acquisition of GTN.

Canadian Mainline The NEB, in its decision on Phase 1 of the 2004 Application, approved virtually all applied-for costs, as well as a new non-renewable firm transportation (FT-NR) service.

In December, the NEB approved TransCanada's application to establish the North Bay Junction as a new receipt and delivery point on the Canadian Mainline.

Alberta System In July 2004, TransCanada received a decision from the EUB on the GCOC proceeding which established an ROE of 9.60 per cent for all Alberta utilities for 2004 and an equity thickness for the Alberta System of 35 per cent.

The EUB disallowed approximately $24 million pre tax of operating costs associated with the operation of the Alberta System in its decision on Phase I of the 2004 GRA which dealt with revenue requirement and rate base.

Simmons became part of the Alberta System on October 1, 2004.

GTN On November 1, 2004, TransCanada acquired GTN which is a high-quality, reliable operation that exemplifies the company's growth strategy.

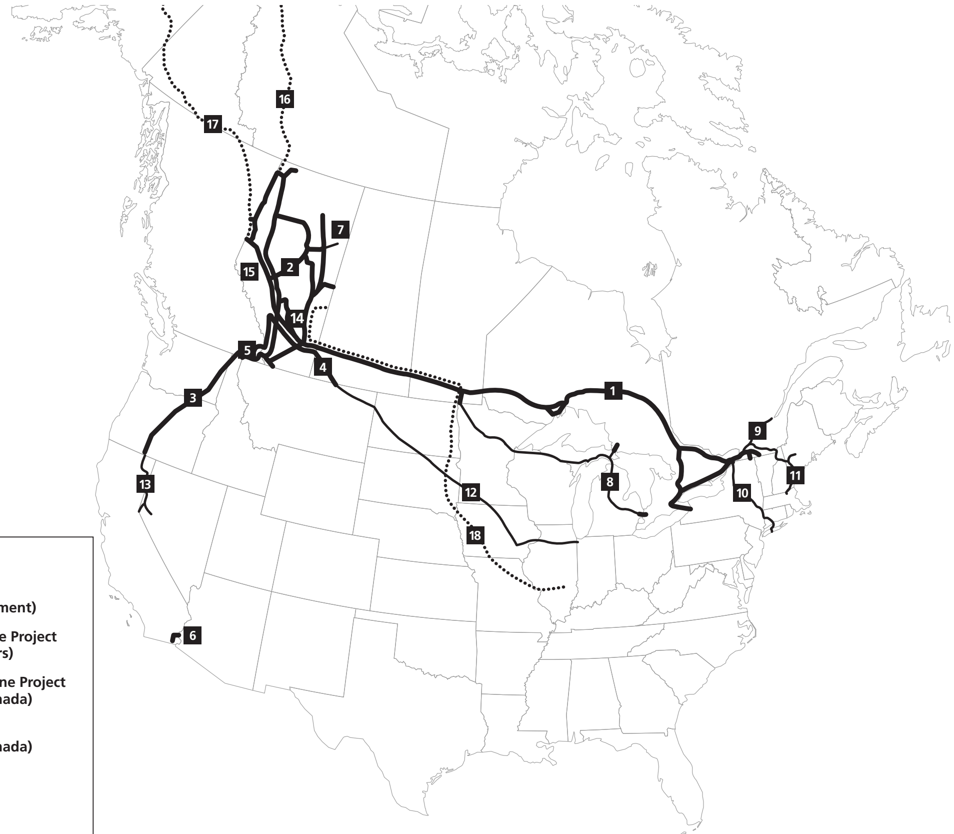
GTN contributed $14 million of earnings for the two months ended December 31, 2004.

Other Gas Transmission In 2004, TransCanada announced plans to develop two new LNG facilities, one in Cacouna, Québec, and one offshore in the New York State waters of Long Island Sound.

In June 2004, TransCanada filed an application under the Alaska Stranded Gas Development Act and proceeded to process its application with the State of Alaska for a right-of-way across State lands for the Alaska Highway Pipeline Project.

TransCanada continued to fund the Aboriginal Pipeline Group's (APG) participation in the Mackenzie Gas Pipeline Project.

TransCanada entered into arrangements that will increase TransCanada's natural gas storage capacity in Alberta commencing in 2005. In January 2005, it announced plans to develop a $200 million natural gas storage project near Edson, Alberta.



GAS TRANSMISSION

1. Canadian Mainline
2. Alberta System
3. Gas Transmission Northwest System
4. Foothills System
5. BC System
6. North Baja System
7. Ventures LP
8. Great Lakes
9. TQM
10. Iroquois
11. Portland
12. Northern Border
13. Tuscarora
14. CrossAlta
15. Edson (under development)
16. Mackenzie Gas Pipeline Project (proposed by producers)
17. Alaska Highway Pipeline Project (proposed by TransCanada)
18. Keystone Pipeline (proposed by TransCanada)

wholly-owned
partially-owned
proposed

Canadian Mainline TransCanada's 100 per cent owned 14,898 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, the Foothills System and other pipelines. The 23,186 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 the Foothills System with Pacific Gas and Electric Company's California Gas Transmission System and with Tuscarora, a partially-owned entity that runs from the Oregon/California border into Nevada.

Foothills System 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 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 System The North Baja System is a 100 per cent owned, 128 km natural gas transmission system that extends from southwestern Arizona to a point near Ogilby, California on the California/Mexico border and connects with a 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.

Great Lakes Great Lakes connects with the Canadian Mainline at Emerson, Manitoba and serves markets in central Canada and the eastern and midwestern U.S. TransCanada has a 50 per cent ownership interest in this 3,387 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.

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 41 per cent ownership interest in this 663 km pipeline system.

Portland Portland is a 471 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.

Northern Border Northern Border is a 2,010 km natural gas pipeline system which serves the U.S. Midwest from a connection with the Foothills System. TransCanada indirectly owns approximately 10 per cent of Northern Border through its 33.4 per cent ownership interest in TC PipeLines, LP.

Tuscarora Tuscarora operates a 386 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 owns an aggregate 17.4 per cent interest in Tuscarora, of which 16.4 per cent is held through TransCanada's interest in TC PipeLines, LP.

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 40 Bcf with a maximum deliverability capability of 410 million cubic feet per day (MMcf/d). TransCanada holds a 60 per cent ownership interest in CrossAlta.

Edson TransCanada is currently developing the Edson natural gas storage facility near Edson, Alberta. The Edson facility will have a capacity of approximately 50 Bcf and will connect to TransCanada's Alberta System. The facility is expected to be in-service in second quarter 2006.

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.

Gas Transmission Net Earnings-at-a-Glance

Year ended December 31 (millions of dollars)	**2004**	2003	2002
Wholly-Owned Pipelines			
Canadian Mainline	**272**	290	307
Alberta System	**150**	190	214
GTN (1)	**14**		
Foothills System (2)	**22**	20	17
BC System	**7**	6	6
	465	506	544
Other Gas Transmission			
Great Lakes	**55**	52	66
Iroquois	**17**	18	18
TC PipeLines, LP	**16**	15	17
Portland (3)	**10**	11	2
Ventures LP	**15**	10	7
TQM	**8**	8	8
CrossAlta	**13**	6	13
TransGas	**11**	22	6
Northern Development	**(6)**	(4)	(6)
General, administrative, support costs and other	**(18)**	(22)	(22)
	121	116	109
Net earnings	**586**	622	653

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

(2) The remaining ownership interests in the Foothills System, previously not held by TransCanada, were acquired on August 15, 2003. Amounts in this table reflect TransCanada's proportionate interest in Foothills' net earnings prior to acquisition and 100 per cent interest thereafter.

(3) TransCanada increased its ownership interest in Portland to 43.4 per cent from 33.3 per cent in September 2003 and to 61.7 per cent from 43.4 per cent in December 2003. Amounts in this table reflect TransCanada's proportionate net earnings from Portland.

In 2004, net earnings from the Gas Transmission business were $586 million compared to $622 million and $653 million in 2003 and 2002, respectively. The decrease in 2004 compared to 2003 was mainly due to lower net earnings from Wholly-Owned Pipelines, partially offset by higher net earnings from Other Gas Transmission. The 2004 decrease in Wholly-Owned Pipelines' net earnings was primarily due to a reduction in the Alberta System's net earnings of $40 million, reflecting the EUB's disallowance of certain operating costs in its decision on Phase I of the 2004 GRA and in its decision in the GCOC proceeding to allow an ROE in 2004 lower than the return implicit in the 2003 revenue requirement settlement with stakeholders.

In addition, net earnings on the Canadian Mainline were lower by $18 million in 2004 compared to 2003 due to a decline in both the average investment base and the allowed ROE. The addition of GTN had a positive effect on 2004 net earnings. Higher 2004 net earnings from Other Gas Transmission were primarily due to increased earnings from CrossAlta and Ventures LP and a $7 million gain on sale of Millennium, partially offset by the negative impact of a weaker U.S. dollar.

The overall decrease of $31 million in 2003 Gas Transmission net earnings compared to 2002 was mainly due to higher incremental earnings in 2002 due to the NEB's Fair Return decision in 2002 and lower investment bases in 2003.

GAS TRANSMISSION – EARNINGS ANALYSIS

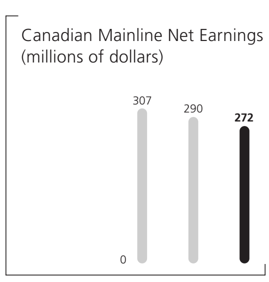
Canadian Mainline The Canadian Mainline is regulated by the NEB. The NEB sets tolls which provide TransCanada the opportunity to recover projected costs of transporting natural gas and provide a return on the Canadian Mainline's average investment base. New facilities are approved by the NEB before construction begins. Changes in investment base, the ROE, the level of deemed common equity and the potential for incentive earnings affect the net earnings of the Canadian Mainline.

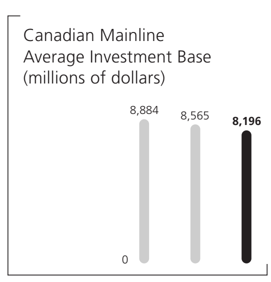
The Canadian Mainline generated net earnings of $272 million in 2004, a decrease of $18 million and $35 million, respectively, when compared to 2003 and 2002 earnings. The decrease in net earnings in 2004 from 2003 is primarily due to a decline in average investment base and allowed ROE. The NEB-approved ROE decreased to 9.56 per cent in 2004 from 9.79 per cent in 2003. The reduction in net earnings from $307 million in 2002 to $290 million in 2003 is due to the combined effect of a lower average investment base and recognition of incremental earnings in 2002 as a result of the NEB's June 2002 Fair Return decision in which it increased the deemed common equity ratio to 33 per cent from 30 per cent effective January 1, 2001. This decision resulted in additional net earnings of $16 million for the year ended December 31, 2001, which the company recognized in 2002.

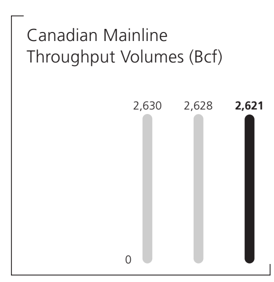
Alberta System The Alberta System is regulated by the EUB primarily under the provisions of the Gas Utilities Act (Alberta) (GUA) and the Pipeline Act (Alberta). Under the GUA, its rates, tolls and other charges, and terms and conditions of service are subject to approval by the EUB.

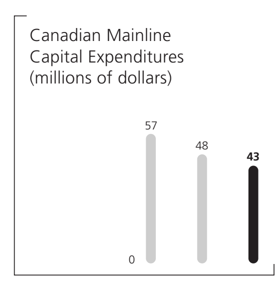
Net earnings of $150 million in 2004 were $40 million lower than 2003 and $64 million lower than 2002. These decreases were primarily due to the impacts of the EUB decisions in respect of Phase I of the 2004 GRA in August 2004 and on the GCOC proceeding in July 2004. In the 2004 GRA Phase I decision, the EUB disallowed approximately $24 million of operating costs associated with the operation of the pipeline. In addition, the GCOC decision resulted in a lower return on deemed common equity in 2004 compared to the earnings implicit in the 2003 and 2002 negotiated settlements which included fixed revenue requirement components, before non-routine adjustments, of $1.277 billion and $1.347 billion, respectively. Net earnings in 2004 reflect a return of 9.60 per cent on deemed common equity of 35 per cent as approved in the GCOC decision. The negative impact of the two EUB decisions on 2004 net earnings was partially offset by lower operating costs.

GTN GTN is regulated by the U.S. Federal Energy Regulatory Commission (FERC), which has authority to regulate rates for natural gas transportation in interstate commerce. Both the Gas Transmission Northwest System and the North Baja System operate under fixed rate models, under which maximum and minimum rates for various service types have been ordered by the FERC and under which GTN is permitted to discount or negotiate rates on a non-discriminatory basis. The Gas Transmission Northwest System's last filed rate case was in 1994 and it was settled and approved by the FERC in 1996. The North Baja System'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 volumes delivered under the various service types









that are provided, as well as by variations in the costs of providing transportation service. Net earnings were $14 million for the two months ended December 31, 2004.

Other Gas Transmission TransCanada's direct and indirect investments in various natural gas pipelines and gas transmission related businesses are included in Other Gas Transmission. It also includes project development activities related to TransCanada's pursuit of new pipeline and natural gas transmission related opportunities throughout North America, including northern gas and LNG.

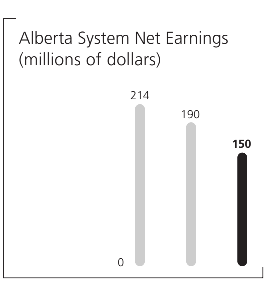
TransCanada's net earnings from Other Gas Transmission in 2004 were $121 million compared to $116 million and $109 million in 2003 and 2002, respectively. The increased net earnings of $5 million in 2004 compared to 2003 were due to higher earnings from CrossAlta, reflecting favourable natural gas storage market conditions in Alberta, higher earnings from Ventures LP as a result of an expansion that was completed in 2003 and higher earnings from Great Lakes as a result of successful marketing of short-term services. In addition, a $7 million gain was recorded on the sale of the company's equity interest in Millennium in 2004. These increases were partially offset by the impact of a weaker U.S. dollar and higher general, administrative and support costs. Earnings for 2003 also included a positive $11 million tax adjustment for TransGas.

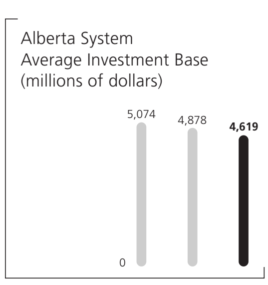
GAS TRANSMISSION – OPPORTUNITIES AND DEVELOPMENTS

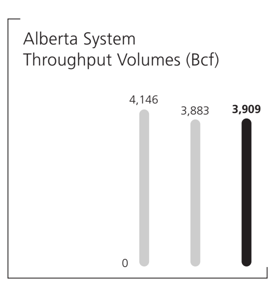
GTN Acquisition TransCanada acquired GTN on November 1, 2004 for approximately US$1.2 billion, excluding assumed debt of approximately US$0.5 billion. The acquisition of GTN complements TransCanada's long-term commitment to serve the Pacific Northwest and California markets, which the company has advanced over the past few years with its 2002 West Path expansion and the purchase of the remaining interests in Foothills in 2003 that it previously did not own. GTN consists of two interstate pipeline systems: the Gas Transmission Northwest System, a 2,174 km pipeline extending from Kingsgate, B.C. on the B.C./Idaho border to Malin, Oregon on the Oregon/California border; and the North Baja System, a 128 km system that extends from Ehrenberg, Arizona to a point near Ogilby, California on the California/Mexico border. The North Baja System is well positioned to provide natural gas transportation services from LNG regasification terminals currently planned to be constructed on the coast of northern Baja California, Mexico.

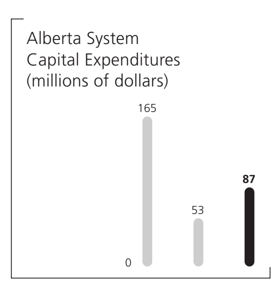
Simmons Acquisition In October 2004, TransCanada acquired Simmons for approximately $22 million. The assets include 380 km of pipeline and metering facilities and four compressor units located in northern Alberta. The system has a capacity of approximately 185 MMcf/d. Simmons delivers natural gas to the Fort McMurray area from several connecting receipt points within the Alberta System, along with production connected directly to the pipeline. Continued development of oil sands resources is expected to increase the demand for natural gas in the Fort McMurray area, as oil sands production requires natural gas supply for hydrogen feedstock, power generation and fuel.

Iroquois In February 2004, the Iroquois pipeline began commercial operation of its Eastchester expansion. The expansion was the first major natural gas transmission pipeline to be built into New York City in approximately 40 years. In January 2004, Iroquois filed a rate application with the FERC to establish rates for the Eastchester









expansion. Iroquois received approval from the FERC in October 2004 of its comprehensive settlement agreement, which implements an eight year rate moratorium for Eastchester. In addition to settling the Eastchester recourse rates, Iroquois also entered into negotiated rate agreements with all of the initial shippers on the Eastchester project.

Portland In August 2004, Portland initiated a restructuring plan whereby all of its operating and administrative functions would be performed by TransCanada pursuant to service agreements. The transition of duties was completed by December 2004.

Supply In 2004, primary supply growth within the WCSB came from northeastern B.C. and the west central foothills area of Alberta. TransCanada attracted incremental volumes from the Sierra discovery in B.C. through the new Ekwan receipt connection and incremental supply from the emerging Cutbank Ridge discovery in B.C. In Alberta, TransCanada saw increased incremental volumes from the central foothills area as well as unconventional production from coalbed methane (CBM), primarily from Horseshoe Canyon coal located in the central Alberta area between Edmonton and Calgary.

TransCanada continues to pursue the most cost effective and timely connection of these volumes, which allows TransCanada's customers to take advantage of continued premium gas price environments. TransCanada will continue to grow by seeking new opportunities to connect additional gas supplies.

Western Markets TransCanada continues to pursue growth opportunities within existing and new natural gas markets. In 2004, TransCanada further executed its strategy to provide cost effective incremental delivery service into the growing Fort McMurray, Alberta market. The acquisition of Simmons was approved by the EUB and the costs of acquiring these assets were added to the Alberta System rate base. The Alberta System's new arrangement for transportation service with Ventures LP was also approved and this service commenced on October 1, 2004.

TransCanada has also negotiated an arrangement with Husky Oil for transportation service on the Kearl Lake Pipeline that will provide the Alberta System an additional 110 MMcf/d delivery capacity. The fast growing production from oil-sands supply in Fort McMurray has also driven expansion in the refining sector of east Edmonton. As a result, TransCanada has negotiated an arrangement for transportation service with ATCO Pipelines (ATCO) that will allow TransCanada to provide incremental delivery service into the industrial market east of Edmonton. Both the Husky Kearl Lake and ATCO transportation service arrangements are included in the 2005 GRA.

Eastern Markets Demand for natural gas continues to be strong in Eastern Canada and Northeast U.S. markets as reflected by the response to several open seasons held on TransCanada's Canadian Mainline. Power generation continues to be the primary driver for incremental natural gas demand in these markets. Ontario and Québec markets continue to develop power projects that require significant incremental natural gas volumes.

Customer behaviour continues to reinforce contract repositioning from long haul to short haul transportation and TransCanada seeks to address these market needs. To that end, TransCanada proposed a new contracting point near North Bay, Ontario to provide customers with additional flexibility. The NEB approval of the NBJ Application in 2004 means the market now has an additional short haul contracting option available.

Northern Development In 2004, TransCanada continued to pursue pipeline opportunities to move both Mackenzie Delta and Alaska North Slope natural gas to markets throughout North America.

TransCanada, the Mackenzie Delta gas producers and the APG reached funding and participation agreements in June 2003 that secured a role for TransCanada in the proposed Mackenzie Gas Pipeline Project and the APG to become an equity participant. This 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. TransCanada has agreed to finance the APG for its one-third share of project development costs. This share is currently expected to be approximately $90 million. The loan will be repaid from the APG's share of available future pipeline revenues. TransCanada funded $26 million of this loan in 2004, for a total of $60 million to December 31, 2004. The ability to recover this investment is dependent upon the outcome of the project. Under the terms of the agreement, TransCanada gains an immediate opportunity to acquire up to five per cent equity ownership of the pipeline at the time of construction. In addition, TransCanada also gains certain rights of first refusal to acquire 50 per cent of any divestitures of existing partners and an entitlement to obtain a one-third interest in all expansion opportunities once the APG reaches a one-third share, with the producers and the APG sharing the balance.

In October 2004, Imperial Oil Resources applied for the main regulatory approvals for the Mackenzie Gas Pipeline Project. These were submitted to the boards, panels and agencies responsible for assessing and regulating energy developments in the Northwest Territories. These filings mark a significant milestone in the project definition phase. TransCanada will continue to support the project through its position established under the various project agreements and to facilitate the interconnection of Mackenzie Delta natural gas into the Alberta System.

In 2004, TransCanada continued its discussions with Alaska North Slope producers and the State of Alaska relating to the Alaskan portion of the Alaska Highway Pipeline Project. In June 2004, TransCanada filed an application under the State of Alaska's Stranded Gas Development Act and requested the State resume processing of its long-pending application for a right-of-way lease across State lands. Once the right-of-way lease application is approved, TransCanada is prepared to convey the lease to another entity if that entity is willing to connect with TransCanada's pipeline system. The lease conveyance would require an interconnection agreement with TransCanada at the Yukon/Alaska border. TransCanada's application is one of three applications currently before the State.

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 NPA, following a lengthy competitive hearing before the NEB in the late 1970's, 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 the facilities in Alberta 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.

LNG In September 2004, TransCanada and Petro-Canada signed a Memorandum of Understanding to develop an LNG facility, Cacouna Energy, in Cacouna, Québec. TransCanada and Petro-Canada will each own 50 per cent of the facility and TransCanada will operate the facility, while Petro-Canada will contract for all of the capacity and supply the LNG. The proposed facility would be capable of receiving, storing and regasifying imported LNG with an average annual send-out capacity of approximately 500 MMcf/d of natural gas. The estimated cost of construction is $660 million. Construction of the facility is subject to regulatory approval from federal, provincial and municipal governments which is expected to take approximately two years. If approval is received, the facility is expected to be in-service towards the end of this decade.

In November 2004, TransCanada and Shell US Gas & Power LLC (Shell) announced plans to jointly develop an offshore LNG regasification terminal, Broadwater Energy, in the New York State waters of Long Island Sound. The proposed floating storage and regasification unit would be located approximately 15 km off the Long Island coast and 18 km off the Connecticut coast. The proposed terminal would be capable of receiving, storing and regasifying imported LNG with an average send-out capacity of approximately one Bcf/d of natural gas. Broadwater Energy LLC, an entity which will be owned 50 per cent by TransCanada, will own and operate the facility, while Shell will contract for all of the capacity and supply the LNG. The estimated cost of construction is expected to be approximately US$700 million. Construction of the facility is subject to regulatory approval from U.S. federal and state governments. The regulatory approval process is expected to take approximately two to three years. TransCanada and Shell have filed a request with the FERC to initiate a six to nine month public review of the Broadwater proposal. Provided the necessary approvals are received, it is expected the facility will be in-service in late 2010.

In a referendum held in March 2004, the residents of Harpswell, Maine voted against leasing a town-owned site to build the Fairwinds LNG regasification facility. As a result, TransCanada and its partner, ConocoPhillips Company, have suspended further work on this LNG project.

Natural Gas Storage In September 2004, TransCanada entered into long-term arrangements, commencing in second quarter 2005, for approximately 20 Bcf of additional natural gas storage capacity in Alberta. The capacity under contract increases to approximately 30 Bcf in 2006 and approximately 40 Bcf in 2007.

In January 2005, TransCanada announced that it is developing a $200 million natural gas storage project near Edson, Alberta. The Edson facility will have a capacity of approximately 50 Bcf and will connect to TransCanada's Alberta System. Storage capacity is expected to be available from the Edson facility commencing in second quarter 2006, on a phased-in basis.

These developments, combined with the company's investment in the CrossAlta natural gas storage facility, position TransCanada to become one of the largest natural gas storage providers in Western Canada. Upon completion of the Edson facility, TransCanada will own or control more than 110 Bcf, or approximately one-third, of the storage capacity in Alberta at that time. Current market fundamentals for natural gas storage are strong. The imbalance in North American natural gas supply and demand has created natural gas price volatility, resulting in demand for storage service. TransCanada believes Alberta-based storage will continue to serve market needs and could play an even more important role when northern gas is connected to North American markets.

Oil Pipeline In February 2005, TransCanada announced that it is proposing a US$1.7 billion oil pipeline project to transport approximately 400,000 barrels per day of heavy crude oil from Alberta to Illinois. The proposed Keystone project would be approximately 3,000 km in length. In addition to new pipeline construction, it would require the conversion of approximately 1,240 km of one of the lines in TransCanada's existing multi-line natural gas pipeline systems in Alberta, Saskatchewan and Manitoba.

TransCanada will continue to meet with oil producers, refiners and industry groups, including the Canadian Association of Petroleum Producers, to gauge additional interest and support for Keystone. Preliminary discussions have begun with stakeholders, including communities, government representatives and landowners along the proposed route. When sufficient support for this project from oil producers and shippers is obtained, TransCanada will proceed with the necessary regulatory applications. TransCanada will require various regulatory approvals from Canadian and U.S. agencies before construction can begin.

TransCanada is in the business of connecting energy supplies to markets and it views this 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.

GAS TRANSMISSION – REGULATORY DEVELOPMENTS

In 2004, TransCanada's principal regulatory activities included the appeal to the Federal Court of Appeal (FCA) of the NEB's February 2003 decision on TransCanada's September 2002 application to review and vary its decision on the fair return for the Canadian Mainline in 2001 and 2002 issued in June 2002; the EUB's GCOC proceeding; the 2004 Application; Phase I and II of the Alberta System's 2004 GRA; and the NBJ proceeding. TransCanada also filed the Alberta System's 2005 GRA-Phase I application. On February 24, 2005, TransCanada advised the EUB that it had reached an agreement in principle for the Alberta System with negotiating parties and requested a suspension of the established regulatory timetable for adjudication of the 2005 GRA pending its finalization of the contemplated settlement agreement. On February 25, 2005, the EUB granted this request. In February 2005, TransCanada reached a settlement with its Canadian Mainline shippers regarding 2005 tolls.

Canadian Mainline In February 2003, the NEB denied TransCanada's September 2002 request for a Review and Variance of the Fair Return decision. TransCanada maintained that the Fair Return decision issued in June 2002 did not recognize the long-term business risks of the Canadian Mainline, which led to an appeal of this decision with the FCA. In May 2003, the FCA granted TransCanada leave to appeal the NEB's February 2003 decision. In April 2004, the FCA dismissed TransCanada's appeal of the NEB's Fair Return Review and Variance decision, while endorsing TransCanada's view of the law relating to the determination of a fair return by the NEB.

In September 2003, TransCanada filed an application to define a new receipt and delivery point near NBJ to better satisfy market requirements. A December 2004 NEB decision approved NBJ as a new contracting point.

In January 2004, TransCanada filed its 2004 Application with the NEB, which included a request for approval of an 11 per cent ROE on deemed common equity of 40 per cent. Given the then pending appeal to the FCA on return issues, the NEB decided to hear the application in a two-phase proceeding, with all matters except cost of capital to be considered in the first phase. In its Phase I decision issued in September 2004, the NEB approved virtually all applied-for costs and the new FT-NR. Upon receipt of the FCA's decision dismissing TransCanada's appeal in April 2004, TransCanada amended its application to an ROE of 9.56 per cent, as determined under the NEB's generic ROE formula, on deemed common equity of 40 per cent. The NEB proceeded to consider cost of capital in the second phase of the proceeding which commenced in November 2004 and continued into 2005. A decision is expected in second quarter 2005.

In November 2004, the Canadian Association of Petroleum Producers (CAPP) filed an application with the NEB to review and vary its Phase I decision with respect to approving tolls for FT-NR to be determined on a biddable basis, allowing TransCanada to include all forecast long-term incentive compensation costs in its 2004 cost of service and allowing TransCanada to recover, through tolls, certain regulatory and legal costs relating to review and appeal proceedings.

On February 18, 2005, having considered whether there was a doubt as to the correctness of its decision on these matters, the NEB decided to review its decision on the toll to be charged for FT-NR service. It also decided not to review its decision on the inclusion of the disputed regulatory and legal costs in tolls. At CAPP's request, the NEB deferred its consideration of a review on its decision regarding long-term incentive compensation costs. As a next step, the NEB will consider the merits of confirming, amending or overturning its decision on the FT-NR toll.

On February 14, 2005, TransCanada announced it had reached a settlement with its Canadian Mainline shippers regarding 2005 tolls. This settlement establishes OM&A costs for 2005 at $169.5 million, which is comparable to the 2004 level. Any variance between actual OM&A costs in 2005 and those agreed to in the settlement will accrue to TransCanada. All other cost elements of the 2005 revenue requirement will be treated on a flow through basis. Further, the 2005 ROE for the Canadian Mainline will be 9.46 per cent as determined under the NEB's generic ROE formula, and the common equity component of the Canadian Mainline's capital structure in 2005 shall be based on the NEB's decision in the recently concluded hearing on the Canadian Mainline's cost of capital for 2004, subject to the outcome of any review applications or appeals.

Alberta System In July 2003, TransCanada, along with other utilities, filed evidence in the EUB's GCOC Proceeding. In this application, TransCanada requested a return of 11 per cent on a deemed common equity of 40 per cent for the Alberta System in 2004. In July 2004, the EUB released its decision on the GCOC Proceeding. In its GCOC decision, the EUB set a generic ROE of 9.60 per cent for all Alberta utilities for 2004 and an equity thickness for the Alberta System of 35 per cent. The EUB decided that the generic ROE in future years will be adjusted by 75 per cent of the change in long-term Canada bonds, consistent with the approach used by the NEB. The EUB also indicated that a review of its ROE adjustment mechanism would not occur prior to 2009, unless the ROE resulting from the application of the ROE formula is less than 7.6 per cent or greater than 11.6 per cent. As for changes in capital structure, the EUB expects changes would only be pursued if there is a material change in investment risk.

In August 2004, TransCanada received the EUB's decision on Phase I of the 2004 GRA which consisted of evidence in support of the applied-for rate base and revenue requirement. The EUB approved depreciation rates which resulted in a composite rate of 4.05 per cent in 2004, the purchase of Simmons and the recovery of costs associated with existing transportation arrangements with the Foothills, Simmons and Ventures LP systems. However, the EUB decision disallowed certain operating and capital costs.

In September 2004, TransCanada filed with the Alberta Court of Appeal for leave to appeal the EUB's decision on Phase I of the 2004 GRA with respect to the disallowance of applied-for incentive compensation costs. In its decision, the EUB disallowed approximately $24 million (pre tax) of operating costs, which included $19 million of applied-for incentive compensation costs. TransCanada believes the EUB made errors of law in deciding to deny the inclusion of these compensation-related costs in the revenue requirement. The company believes these are necessary costs that it reasonably and prudently incurs for the safe, reliable and efficient operation of the Alberta System. At the request of TransCanada, the Court of Appeal adjourned the appeal for an indefinite period of time while TransCanada considers the merits of a review and variance application to the EUB in respect of 2004 costs, and works toward a negotiated settlement of future years' tolls with its customers.

In October 2004, the EUB approved Phase II of the 2004 GRA, which primarily dealt with rate design and services. The EUB also directed TransCanada to file a 2005 GRA-Phase II application on or before April 1, 2005 to address certain cost allocation issues related to rate design.

In December 2004, TransCanada filed its 2005 Phase I GRA with the EUB. On February 24, 2005, TransCanada advised the EUB that it had reached an agreement in principle for the Alberta System with negotiating parties and requested a suspension of the established regulatory timetable for adjudication of the 2005 GRA pending its finalization of the contemplated settlement agreement. On February 25, 2005, the EUB granted this request.

GAS TRANSMISSION – 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 an increasingly mature WCSB and markets served by TransCanada's pipelines. In addition, the continued expiration of transportation contracts has resulted in significant reductions in firm contracted capacity on both the Canadian Mainline and Alberta System.

As of December 2003, the WCSB had remaining discovered natural gas reserves of 55 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, WCSB 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 provides the major natural gas gathering and export transportation capacity for the WCSB by connecting to most of the natural gas processing plants in Alberta and then transporting natural gas for domestic and export deliveries. The Alberta System faces competition primarily from the Alliance Pipeline, a natural gas pipeline from northeast B.C. to the Chicago area for ex-Alberta deliveries. In addition, the Alberta System has faced, and will continue to face, increasing competition from other pipelines.

The Canadian Mainline is TransCanada's cross-continent natural gas pipeline serving mid-western 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 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 U.S. Northeast 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 Canadian, Atlantic Canadian and U.S. supplies.

The Canadian Mainline has experienced reductions in long haul FT contracts. This has been partially offset by an increase in short haul contracts. While decreases in throughput do not directly impact Canadian Mainline earnings, such decreases will impact the competitiveness of its tolls. Looking forward, in the short to medium term, there is limited opportunity to reduce tolls by increasing long haul volumes on the Canadian Mainline.

The Gas Transmission Northwest System must compete with other pipelines for access to natural gas supplies and its 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 on the Gas Transmission Northwest System in relation to natural gas supplies from the other supply regions serving these markets. 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 southwest U.S. supply basins. In the Pacific Northwest market, natural gas transported on the Gas Transmission Northwest System competes against Rocky Mountain gas supply as well as additional western Canadian supply that is transported by Williams' Northwest Pipeline.

Transportation service on the North Baja System 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. The North Baja System delivers gas to 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 the North Baja System'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. The North Baja System's market is near locations of interest for LNG development companies who may be interested in delivering foreign natural gas supplies to the area.

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 the approved financial returns discourage additional investment in existing Canadian natural gas transmission systems. TransCanada had applied for a return of 11 per cent on 40 per cent deemed common equity, both to the NEB in the Canadian Mainline's 2004 Application and to the EUB in the Alberta System's application in the GCOC proceeding. In its GCOC decision, the EUB set a generic ROE of 9.60 per cent for all Alberta utilities for 2004 and a deemed equity thickness for the Alberta System of 35 per cent. Following the FCA's decision, TransCanada revised its 2004 Application to reflect a return of 9.56 per cent based on the NEB formula on 40 per cent common equity. The NEB's deliberations on the 2004 Application respecting these matters are currently under way with a decision expected in second quarter 2005.

The company is cognisant of the views and shares the concerns of credit rating agencies regarding the Canadian regulatory environment. Credit ratings and liquidity have risen to the forefront of investor attention. In light of the developments in the Canadian regulatory environment, there exists a view that current Canadian regulatory policy is eroding the credit worthiness of utilities which, over the long term, could make it increasingly difficult for utilities to access capital on reasonable terms.

Foreign Exchange TransCanada's earnings from GTN, as well as a significant amount of earnings in Other Gas Transmission are generated in U.S. dollars. The performance of the Canadian dollar relative to the U.S. dollar would either positively or negatively impact Gas Transmission's net earnings.

Throughput Risk As transportation contracts expire on Great Lakes, Northern Border and GTN, these pipelines will be more exposed to throughput risk and their revenues will more likely experience increased variability. Throughput risk is created by supply availability, economic activity, weather variability, pipeline competition and pricing of alternative fuels.

Regulation The Alberta System is regulated by the EUB. The remaining Canadian pipelines, other than Ventures LP, are regulated by the NEB. In the U.S., TransCanada's wholly- and partially-owned pipelines are regulated by the FERC. These regulators approve the pipelines' respective ROE, costs of service, capital structures, tolls and system expansions.

GAS TRANSMISSION – OTHER

Operational Excellence TransCanada continued its commitment to operational excellence in 2004 by further advancing initiatives that will improve the company's ability to provide low-cost, reliable and responsive service to customers. TransCanada continues to pursue this strategy in order to become the preferred company that customers choose to connect new natural gas supplies and markets.

In 2004, TransCanada reduced operating and maintenance costs through rationalizing maintenance and streamlining the delivery of services. The company met its ongoing goals in the management of greenhouse gases. TransCanada also achieved a high level of plant operating performance, as measured by the number of operational perfect days on both the Canadian Mainline and the Alberta System.

In 2004, TransCanada maintained high levels of customer satisfaction with the launch of a new website called "Customer Express". Customer Express is integrated into TransCanada's website and provides customers with more efficient access to commercial information needed to make transportation decisions. Customer feedback indicates this new website was very well received. Also, through a collaborative effort with customers, a new long-haul firm transportation service enhancement (FT-RAM) was offered on a one year pilot basis beginning November 1, 2004. The purpose of FT-RAM is to mitigate unutilized demand charges and provide greater flexibility in order to attract and retain contracts for FT service.

In 2005, TransCanada will continue to focus efforts on efficiencies, operational reliability, and environmental and safety performance. Greenhouse gas emissions management programs will continue to receive focused attention. Additional effort will be undertaken in 2005 with respect to improving contractor safety performance.

Safety TransCanada worked closely with regulators, customers and communities during 2004 to ensure the continued safety of employees and the public. Pipeline safety performance in 2004 was excellent with no line-breaks or other serious incidents. Under the approved regulatory models in Canada, expenditures on pipeline integrity have no negative impact on earnings. The company expects to spend approximately $70 million in 2005 for pipeline integrity on its Wholly-Owned Pipelines, which is comparable to amounts spent in 2004. 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.

Environment In 2004, TransCanada continued to conduct activities to increase environmental protection through proactive sampling, remediation and monitoring programs. Compressor stations on the Alberta System have been assessed through the company's Site Assessment, Remediation & Monitoring program. In 2004, TransCanada invested in improved environmental protection measures. This program of actively assessing and addressing environmental issues will continue into the future. In addition, the decommissioning of six Canadian Mainline compressor plants and two Alberta compressor plants was undertaken in 2004, effectively reclaiming each project site.

For information on management of risks with respect to the Gas Transmission business, see the Risk Management section.

GAS TRANSMISSION – OUTLOOK

TransCanada's Gas Transmission business has a long history of providing pipeline capacity to markets and connecting natural gas supply for the company's customers. As the marketplace has evolved and competition has grown, Gas Transmission has focused on providing market-responsive products and services, competitive cost-effective structures and the highest levels of reliability to customers.

TransCanada continues to actively pursue pipeline and natural gas transmission-related development and acquisition opportunities in North America, where these opportunities are driven by strong customer demand and sound economics. The company will continue to evaluate options in a disciplined fashion to maintain a strong financial position.

World geo-political events will have an impact on the level of development of future and existing natural gas supplies worldwide. This could directly impact TransCanada, with the company expanding existing facilities across North America and being involved in the development of alternative natural gas transportation solutions as producers access northern and Atlantic Canada natural gas reserves.

TransCanada is committed to play a key role in northern gas development. While there are many issues to be resolved before this moves forward, TransCanada has advantages including expertise in the design, construction and operation of large diameter pipe in cold weather conditions. TransCanada is also the leading operator of large natural gas turbine compressor stations, owns and operates one of the largest, most sophisticated, remote-controlled pipeline networks in the world and has a solid reputation for safety and reliability. This positions the company well to play a key role in bringing northern gas to market.

In 2005, the company will continue to focus on achieving additional efficiency improvements in all aspects of the business by maintaining focus on operational excellence and leveraging technological advancements. TransCanada will also continue to work collaboratively with all stakeholders on negotiated settlements and the evolution of services that will increase the value of TransCanada's business to customers and shareholders.

Looking forward, as the supply/demand balance tightens, producers will continue to explore and develop new fields, particularly in northeastern B.C. and the central foothills regions of Alberta, as well as unconventional supply such as gas production from CBM reserves. In addition, TransCanada anticipates filing an application in 2005 with the EUB to construct Alberta System facilities required to connect additional natural gas supplies delivered to the Alberta System from the Mackenzie Delta.

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, due to depreciation, a continued decline in the average investment base. Accordingly, without an increase in ROE, deemed common equity or incentive opportunities, future earnings 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.

Earnings On February 14, 2005 TransCanada announced it had reached a settlement with its Canadian Mainline shippers regarding 2005 tolls. This settlement essentially establishes an OM&A at-risk model for 2005 and has fixed OM&A at a level comparable to 2004. This OM&A at-risk settlement will provide some opportunity for incentive earnings as TransCanada continues to focus efforts on cost efficiencies in 2005. This settlement also establishes the 2005 ROE for the Canadian Mainline at 9.46 per cent as determined under the NEB formula, and its capital structure for 2005 to be subject to the outcome of the recently concluded hearing of the 2004 Application – Phase II.

In February 2005, TransCanada reached an agreement in principle with its Alberta System shippers on a revenue requirement settlement for the period January 1, 2005 to December 31, 2007. TransCanada is proceeding with finalizing the terms of the settlement with the negotiating parties and anticipates executing the settlement agreement in March 2005. TransCanada expects to file the settlement agreement with the EUB for approval shortly thereafter.

In 2005, there will be a full year's contribution from GTN, which was acquired on November 1, 2004.

Net earnings for Other Gas Transmission in 2005 will be affected by factors such as the level of project development costs and the performance of the Canadian dollar relative to the U.S. dollar.

Capital Expenditures Total capital spending for the Canadian wholly-owned pipelines during 2004 was $132 million. Overall capital spending on the Wholly-Owned Pipelines, including GTN, in 2005 is expected to be approximately $171 million. Capital expenditures on the Edson natural gas storage project are expected to be approximately $150 million in 2005.

Natural Gas Throughput Volumes

(Bcf)	**2004**	2003	2002
Canadian Mainline (1)	**2,621**	2,628	2,630
Alberta System (2)	**3,909**	3,883	4,146
Gas Transmission Northwest System (3)	**181**		
Foothills System	**1,139**	1,110	1,098
BC System	**360**	325	371
Great Lakes	**801**	856	863
Northern Border	**845**	850	839
Iroquois	**356**	341	340
TQM	**159**	164	175
Ventures LP	**136**	111	85
Portland	**50**	53	52
Tuscarora	**25**	22	20
TransGas	**18**	16	16

(1) Canadian Mainline deliveries originating at the Alberta border and in Saskatchewan for the year ended December 31, 2004 were 2,017 Bcf (2003 – 2,055 Bcf; 2002 – 2,221 Bcf).

(2) Field receipt volumes for the Alberta System for the year ended December 31, 2004 were 3,952 Bcf (2003 – 3,892 Bcf; 2002 – 4,101 Bcf).

(3) TransCanada acquired GTN on November 1, 2004. The North Baja System's total delivery volumes were 13 Bcf. The delivery volumes represent November and December 2004 throughput.

POWER

HIGHLIGHTS

Net Earnings Power's net earnings in 2004 were $396 million compared to $220 million in 2003 with the increase primarily due to $187 million of gains related to Power LP.

Power's net earnings for 2004, excluding the $187 million of gains related to Power LP, would have been $209 million which was an increase of $8 million compared to $201 million in 2003, excluding a positive settlement in 2003 of $19 million after tax with a former counterparty.

Bruce Power Pre-tax equity income from Bruce Power of $130 million in 2004 increased $31 million compared to TransCanada's period of ownership in 2003.

Unit 3 returned to service in first quarter 2004 increasing TransCanada's share of nominal generating capacity of Bruce Power to 1,487 MW.

A feasibility study was commenced with respect to the restart of Units 1 and 2.

A study of a potential investment in the refurbishment of the 680 MW Point Lepreau nuclear generating station in New Brunswick was commenced.

Expanding Asset Base TransCanada announced it will proceed with the purchase of hydroelectric generation assets from USGen with a total generating capacity of 567 MW for US$505 million. The acquisition is subject to regulatory approvals and pending the sale of the 49 MW Bellows Falls hydroelectric facility to Vermont Hydroelectric. If Vermont Hydroelectric acquires Bellows Falls, for which it exercised a pre-existing option to purchase, the purchase price will be reduced by US$72 million to US$433 million for generating capacity of 518 MW.

The MacKay River plant in Alberta was placed in-service in 2004.

Construction of the 90 MW Grandview cogeneration plant was completed on time and within budget.

Construction commenced in third quarter 2004 of the 550 MW Bécancour natural gas-fired cogeneration power plant in Québec to be in-service in late 2006.

TransCanada announced that Hydro-Québec awarded Cartier Wind, owned 62 per cent by TransCanada, six projects totalling 739.5 MW which are scheduled to be commissioned between 2006 and 2012.

The company responded to the Ontario government's Request For Proposals for 2,500 MW of new electricity generation capacity.

Plant Availability Weighted average plant availability was 96 per cent in 2004, excluding Bruce Power, compared to 94 per cent in 2003.

Including Bruce Power, weighted average plant availability remained the same in 2004 as 2003 at 90 per cent.

Power Net Earnings-at-a-Glance

Year ended December 31 (millions of dollars)	**2004**	2003	2002
Western operations	**138**	160	131
Eastern operations	**108**	127	149
Bruce Power investment	**130**	99	
Power LP investment	**29**	35	36
General, administrative, support costs and other	**(89)**	(86)	(73)
Operating and other income	**316**	335	243
Financial charges	**(13)**	(12)	(13)
Income taxes	**(94)**	(103)	(84)
	209	220	146
Gains related to Power LP (after tax)	**187**	–	–
Net earnings	**396**	220	146

Power's net earnings in 2004 of $396 million increased $176 million compared to $220 million in 2003, primarily due to $187 million of gains related to Power LP recorded in 2004. On April 30, 2004, TransCanada sold the ManChief and Curtis Palmer power facilities to Power LP for US$402.6 million, excluding closing adjustments, resulting in an after-tax gain on sale of $15 million (pre-tax gain of $25 million). At a meeting in April 2004, Power LP unitholders approved these acquisitions and the removal of Power LP's obligation to redeem all units not owned by TransCanada in 2017. TransCanada was required to fund this redemption, thus the removal of Power LP's obligation eliminated this requirement. To partially finance the acquisition, Power LP issued 8.1 million subscription receipts which were subsequently converted into partnership units and TransCanada contributed $20 million of the net proceeds of $286.8 million from this issue. This issue also reduced TransCanada's ownership interest in Power LP from 35.6 per cent to 30.6 per cent. As a result of these events, TransCanada recognized dilution and other gains of $172 million in 2004, $132 million of which were previously deferred and were being amortized into income to 2017. Dilution gains arose when TransCanada's ownership interest in Power LP was decreased at different times as a result of Power LP issuing new partnership units at a market price in excess of TransCanada's per unit carrying value of the investment.

The 2003 results include recognition in Western Operations of a $31 million pre-tax ($19 million after-tax) settlement with a former counterparty that defaulted in 2001 under power forward contracts. Power's net earnings for 2004, excluding the $187 million of gains related to Power LP in 2004, would have been $209 million which was an increase of $8 million compared to $201 million in 2003, excluding the positive settlement with a former counterparty. Pre-tax equity income from Bruce Power of $130 million in 2004 increased $31 million compared to TransCanada's period of ownership in 2003. This was partially offset by lower contributions from Eastern Operations and Power LP investment.

Power's net earnings of $220 million in 2003 increased $74 million or 51 per cent compared to earnings of $146 million in 2002. This increase is primarily attributable to the February 2003 acquisition of a 31.6 per cent interest in Bruce Power and higher contributions from Western Operations relating to the settlement with a former counterparty. Partially offsetting these increases were lower earnings from Eastern Operations and higher general, administrative, support costs and other associated with TransCanada's focus on growth of the Power business.

POWER GENERATION

1 Bear Creek	**TransCanada Power, L.P.** (30.6 per cent)
2 MacKay River	14 Curtis Palmer
3 Redwater	15 ManChief
4 Sundance A PPA	16 Williams Lake
5 Sundance B PPA (50 per cent)	17 Nipigon
6 Carseland	18 Kapuskasing
7 Cancarb	19 Tunis
8 Bruce Power (31.6 per cent)	20 North Bay
9 OSP	21 Calstock
10 Bécancour (under construction)	22 Castleton
11 Cartier Wind (proposed)	23 Mamquam
12 Grandview	24 Queen Charlotte
13 USGen (pending acquisition)	

Bear Creek Commercial operation of this 80 MW natural gas-fired cogeneration plant near Grande Prairie, Alberta commenced in March 2003.

MacKay River This 165 MW natural gas-fired cogeneration plant near Fort McMurray, Alberta was placed in-service in 2004.

Redwater Commercial operation of this 40 MW natural gas-fired cogeneration plant near Redwater, Alberta commenced in January 2002.

Sundance A&B The Sundance power facility in Alberta is the largest coal-fired electrical generating facility in Western Canada. TransCanada owns the Sundance A PPA, which increased the company's power supply by 560 MW for a 17 year period commencing in 2001. TransCanada effectively owns 50 per cent of the 706 MW Sundance B PPA through a partnership arrangement, which increased the company's power supply by 353 MW for approximately 19 years commencing in 2002.

Carseland Commercial operation of this 80 MW natural gas-fired cogeneration plant near Carseland, Alberta commenced in January 2002.

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 In February 2003, TransCanada acquired a 31.6 per cent equity interest in Bruce Power, which operates the Bruce nuclear power facility located near Lake Huron, Ontario. This investment indirectly increased TransCanada's nominal generating capacity initially by approximately 1,000 MW, with an additional 474 MW added with the restart of two laid-up units in late 2003 and early 2004.

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

Bécancour The 550 MW Bécancour natural gas-fired cogeneration power plant located near Trois-Rivières, Québec is under construction and is expected to be in-service in late 2006. The entire power output will be supplied to Hydro-Québec under a 20 year power purchase contract. Steam will also be supplied to local businesses.

Cartier Wind Cartier Wind, 62 per cent owned by TransCanada, announced in fourth quarter 2004 it was awarded six wind projects by Hydro-Québec totalling 739.5 MW to be commissioned between 2006 and 2012. Construction on the first project is expected to commence in late 2005.

Grandview Construction of the 90 MW Grandview natural gas-fired cogeneration power plant located in Saint John, New Brunswick was completed by the end of 2004. Under a 20 year tolling arrangement, 100 per cent of the plant's heat and electricity output will be sold to Irving Oil.

USGen In fourth quarter 2004, TransCanada announced it intends to purchase hydroelectric generation assets from USGen. The assets expected to be purchased have a total generating capacity of 518 MW and are situated on two rivers in New England. The output is not sold under long-term contracts. The transaction is expected to close in the first half of 2005.

Curtis Palmer The 60 MW Curtis Palmer hydroelectric facility near Corinth, New York was sold to Power LP in second quarter 2004. All output from this facility is sold through a fixed-priced, long-term agreement.

ManChief The 300 MW simple-cycle ManChief facility near Brush, Colorado was sold to Power LP in second quarter 2004. The entire capacity of this natural gas-fired plant is sold under long-term tolling contracts that expire in 2012.

Williams Lake Power LP owns a 66 MW wood waste-fired power plant at Williams Lake, B.C.

Nipigon, Kapuskasing, Tunis and North Bay These efficient, enhanced combined-cycle facilities are fuelled by a combination of natural gas and waste heat exhaust from adjacent compressor stations on the Canadian Mainline and are owned by Power LP.

Calstock Calstock, a 35 MW plant, is fuelled by a combination of wood waste and waste heat exhaust from the adjacent Canadian Mainline compressor station and is owned by Power LP.

Castleton Castleton is a 64 MW combined-cycle plant located at Castleton-on-Hudson, New York and is owned by Power LP.

Mamquam and Queen Charlotte The 50 MW Mamquam and 6 MW Queen Charlotte hydroelectric facilities are located in B.C. All energy produced from these facilities is contracted long term to B.C. Hydro and Power Authority. The assets were purchased by Power LP in third quarter 2004.

Paiton Paiton owns a power project consisting of two 615 MW coal-fired power units located in Indonesia. TransCanada effectively holds an approximate 11 per cent interest in Paiton.

Power Plants – Nominal Generating Capacity and Fuel Type

	MW	Fuel Type
Western operations		
Sundance A (1)	560	Coal
Sundance B (1)	353	Coal
MacKay River	165	Natural gas
Carseland	80	Natural gas
Bear Creek	80	Natural gas
Redwater	40	Natural gas
Cancarb	27	Natural gas
	1,305	
Eastern operations		
OSP	560	Natural gas
Bécancour (2)	550	Natural gas
Cartier Wind (3)	458	Wind
USGen (4)	518	Hydro
Grandview (5)	90	Natural gas
	2,176	
Bruce Power investment (6)	1,487	Nuclear
Power LP investment (7)		
ManChief	300	Natural gas
Williams Lake	66	Wood waste
Castleton	64	Natural gas/waste heat
Curtis Palmer	60	Hydro
Mamquam and Queen Charlotte	56	Hydro
Tunis	43	Natural gas/waste heat
Nipigon	40	Natural gas/waste heat
Kapuskasing	40	Natural gas/waste heat
North Bay	40	Natural gas/waste heat
Calstock	35	Wood waste/waste heat
	744	
Total Nominal Generating Capacity	5,712	

(1) 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.

(2) Currently under construction.

(3) Currently in pre-construction design phase. Represents TransCanada's 62 per cent of 739.5 MW.

(4) The purchase transaction is expected to close in the first half of 2005. The 518 MW excludes the Bellows Falls facility.

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

(6) Represents TransCanada's 31.6 per cent equity interest in Bruce Power. Bruce A consists of four 750 MW reactors. Bruce A Unit 4 was returned to service in fourth quarter 2003. Bruce A Unit 3 was returned to service in first quarter 2004. Bruce A Units 1 and 2 remain in a laid-up state. Bruce B consists of four reactors, which are currently in operation, with a capacity of approximately 3,200 MW. The generating capacity includes 2 MW from TransCanada's 17 per cent indirect share in Huron Wind L.P. which owns a 9 MW wind farm near Bruce Power.

(7) At December 31, 2004, TransCanada operated and managed Power LP and held a 30.6 per cent ownership interest in Power LP. The volumes in the table represent 100 per cent of plant capacity.

POWER – EARNINGS ANALYSIS

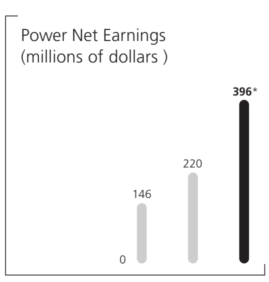
Western Operations The focus of Western Operations is to optimize and expand its existing asset base and maximize asset value through a combination of long- and short-term contracts for power and steam sales. The asset portfolio is among the lowest cost, most competitive generation in the market area. Western Operations directly controls more than 1,300 MW of power supply in Alberta from its five gas-fired co-generation facilities and two Sundance long-term PPAs.

Western Operations has two integrated functions – marketing and plant operations. Based in Calgary, Alberta, the marketing function purchases and resells electricity related to the Sundance PPAs, markets uncommitted generation from the Alberta plants and purchases and resells power and gas to maximize the value of its asset base. Plant operations primarily consists of the Alberta power plants and fees earned to manage and operate the Power LP.

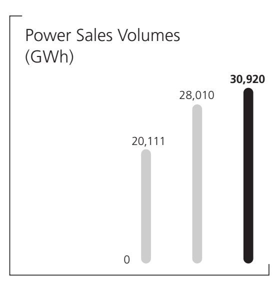
The marketing function is integral to optimizing Power's return from its assets and managing risks around uncontracted volumes. A significant portion of plant generation is sold under long-term contract to mitigate price risk. Some output is intentionally not committed under long-term contract to assist in managing Power's overall portfolio of generation. 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 2004, 86 per cent of total sales volumes were sold under medium- to long-term contracts. The marketing function's primary role is to manage these open positions and it will also, at times, purchase and re-sell both power and gas in an effort to optimize contributions from each of the generation facilities. In order to mitigate market price risk, Western Operations has sold approximately 81 per cent of the total generation for 2005 and 65 per cent of the expected, average combined total power supply for the next three years. Western Operations' largest power supply comes from its Sundance PPAs. TransCanada has sold essentially all of the Sundance PPAs' power supply in 2005 and 80 per cent and 52 per cent of the expected combined power supply for 2006 and 2007, respectively.

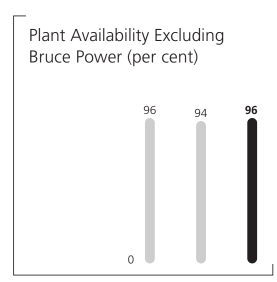
With the placing in-service of the MacKay River cogeneration facility in 2004, plant operations currently consists of five plants in Alberta with a total generating capacity of approximately 400 MW. The expansion of Alberta generation is consistent with TransCanada's focus on capitalizing on the company's expertise in developing new projects and maintaining its position in a region it knows well. In second quarter 2004, and consistent with TransCanada's portfolio management strategy to divest mature assets and redeploy capital, TransCanada sold the 300 MW ManChief power facility to Power LP.

Operating and other income for 2004 of $138 million was $22 million lower compared to the same period in 2003. The decrease was mainly due to a positive $31 million pre-tax ($19 million after-tax) settlement in June 2003 with a former counterparty that defaulted in 2001 under power forward contracts, as well as reduced income from ManChief following the sale of the plant to Power LP in April 2004. Partially offsetting these decreases were contributions from the MacKay



*Includes $187 million gains related to Power LP.





River plant which was placed in-service in 2004, fees earned with respect to Power LP's asset acquisitions in 2004 and the impact of higher net margins achieved in second and third quarter 2004 on the overall portfolio.

In 2003, operating and other income from Western Operations increased by 22 per cent to $160 million from $131 million in 2002 due primarily to the 2003 settlement with a former counterparty. A full year of earnings from the ManChief plant, which was acquired in late 2002, higher contributions from the Sundance PPAs reflecting lower transmission costs and higher earnings from the Alberta plants also contributed to higher operating income. Offsetting these increases were the effects in 2003 of lower prices achieved on the overall sale of power and the higher cost of natural gas fuel at the Cancarb carbon black facility.

Eastern Operations Eastern Operations is focused on the New England and New York deregulated power markets in the U.S. and on development opportunities in Ontario, Québec and New Brunswick. TransCanada Power Marketing Limited (TCPM), located in Westborough, Massachusetts, continues to navigate through New England's deregulation process and firmly establish itself as a leading energy provider and marketer in the New England power market.

TransCanada's success in the Northeast U.S. is the direct result of a knowledgeable region-specific marketing operation which is conducted through TCPM. TCPM is focused on selling power under contract to wholesale, commercial and industrial customers while managing a portfolio of power supplies sourced from its own generation, wholesale power purchases and power purchased from the output of Power LP's 64 MW Castleton plant in New York State. In fourth quarter 2004, TransCanada closed a transaction with Boston Edison Company (Boston Edison) resulting in the company assuming the remaining 23.5 per cent share of the OSP power purchase contracts. All of the OSP output is now marketed by TCPM. TCPM is a full service provider offering varied products and services to assist customers in managing their power supply and power prices in deregulated power markets.

Eastern Operations' power generation assets include OSP and Grandview. OSP is a 560 MW natural gas-fired plant located in Rhode Island. Grandview is a 90 MW natural gas-fired cogeneration facility on the site of the Irving Oil Refinery in Saint John, New Brunswick. Construction of the Grandview facility was complete at the end of 2004 and it was commissioned in first quarter 2005. Under a 20 year tolling arrangement, Irving will provide fuel for the plant and contract for 100 per cent of the plant's heat and electricity output. On April 30, 2004, and consistent with TransCanada's portfolio management strategy to divest mature assets and redeploy capital, TransCanada sold the 60 MW Curtis Palmer hydroelectric power facility to Power LP.

Operating and other income for 2004 was $108 million or $19 million lower than the $127 million earned in 2003. This decrease was mainly due to a reduction in income as a result of the sale of the Curtis Palmer hydroelectric facilities to Power LP in April 2004, the unfavourable impact of higher natural gas fuel costs at OSP and a weaker U.S. dollar in 2004. Partially offsetting these decreases was a $16 million positive impact from the restructuring transaction related to the power purchase contracts between OSP and Boston Edison. TransCanada recognized earnings from the transaction's effective date of April 1, 2004.

Operating and other income for 2003 from Eastern Operations was $127 million compared to $149 million in 2002. The $22 million decrease was primarily due to the impact of higher natural gas fuel costs at OSP resulting from an arbitration process and the unfavourable impact of a weaker U.S. dollar. Partially offsetting these decreases were incremental earnings from the growth in volumes and margins on sales to wholesale, commercial and industrial customers. In addition, 2003 had higher earnings from Curtis Palmer as a result of above average water flows and revenue earned from a temporary generation facility operated in Cobourg, Ontario during the summer of 2003.

In late 2004, management conducted a review of the operating plan for OSP with respect to the negative impacts of a third arbitration received in August 2004 whereby OSP's cost of fuel gas substantially increased to a price in excess of market. The outcome of a fourth arbitration is expected by the end of third quarter 2005. At December 31, 2004, there was determined to be no impairment of OSP; however, there existed uncertainty with respect to the outcome of this arbitration process and future market conditions. Should the fourth arbitration decision continue to support a pricing mechanism for fuel gas in excess of market price and if anticipated market conditions do not change substantially, management expects the negative impact of the continued above-market gas prices could result in an asset impairment write-down of the OSP facility. The net carrying value of OSP at December 31, 2004 was approximately US$150 million.

Bruce Power Investment On February 14, 2003, the company completed the acquisitions of a 31.6 per cent interest in Bruce Power and 33.3 per cent interest in Bruce Power Inc., the general partner of Bruce Power, for $409 million. TransCanada also funded, through a loan arrangement, a one-third share ($75 million) of a $225 million accelerated deferred rent payment made by Bruce Power to Ontario Power Generation (OPG). TransCanada acquired the interests as part of a consortium (the Consortium) that includes Cameco Corporation (Cameco) and BPC Generation Infrastructure Trust, a trust established by the Ontario Municipal Employees Retirement System. Under the agreement, the Consortium acquired British Energy (Canada) Ltd., which owned a 79.8 per cent interest in Bruce Power as well as a 50 per cent interest in the nine MW Huron Wind L.P. power facility. Located in Ontario, the Bruce Power facility is comprised of two nuclear plants – Bruce A and Bruce B. Bruce B consists of four reactors with a capacity of approximately 3,200 MW. Bruce A consists of four reactors which, up until 2003, were not operating. In fourth quarter 2003, Bruce Power completed commissioning of Bruce A Unit 4 and in first quarter 2004, it completed commissioning of Unit 3. These two Bruce A units added 1,500 MW of capacity, bringing Bruce Power's total capacity to approximately 4,700 MW.

Bruce Power is the tenant under a lease with OPG on the Bruce nuclear power facility. The lease expires in 2018 with an option to extend the lease by up to 25 years. The Bruce Power nuclear facility continues

Bruce Power Results-at-a-Glance

Year ended December 31 (millions of dollars)	2004	2003
Bruce Power (100 per cent basis)		
Revenues	**1,583**	1,208
Operating expenses	**(1,178)**	(853)
Operating income	**405**	355
Financial charges	**(67)**	(69)
Income before income taxes	**338**	286
TransCanada's interest in Bruce Power income before income taxes (1)	**107**	65
Adjustments (2)	**23**	34
TransCanada's income from Bruce Power before income taxes	**130**	99

(1) TransCanada acquired its interest in Bruce Power on February 14, 2003. Bruce Power's 100 per cent income before income taxes from February 14 to December 31, 2003 was $205 million.

(2) See Note 8 to the December 31, 2004 consolidated financial statements for an explanation of the purchase price amortizations. The amount allocated to the investment in Bruce Power includes a purchase price allocation of $301 million to the initial lease of the Bruce Power plant which is being amortized on a straight-line basis over the lease term that extends to 2018, resulting in an annual amortization expense of $19 million. The amount allocated to the power sales agreements is being amortized to income over the remaining term of the underlying sales contracts. The amortization of the fair value allocated to these contracts is: 2003 – $38 million; 2004 – $37 million; 2005 – $25 million; 2006 – $29 million; and 2007 – $2 million.

to be managed and operated by the management and staff of Bruce Power. Spent fuel and decommissioning liabilities remain the responsibility of OPG but the lease agreement with OPG provides for adjustments to the base rent every five years contingent upon the projected decommissioning costs for the Bruce Power facility.

TransCanada's share of power output from Bruce Power in 2004 was 10,608 gigawatt hours (GWh). This includes power output from Unit 3 from March 1, 2004. Unit 3 began producing electricity to the Ontario electricity grid on January 8, 2004 and was considered commercially in-service March 1, 2004. Bruce Power's cumulative restart cost for Units 3 and 4 was approximately $720 million.

Pre-tax equity income for 2004 was $130 million compared to $99 million for the same period in 2003. This increase was primarily due to higher output in 2004 as a result of the return to service of Units 3 and 4 as well as a full year of earnings in 2004 compared to earnings from February 14 to December 31 in 2003, reflecting TransCanada's period of ownership in 2003.

Adjustments to TransCanada's interest in Bruce Power income before income taxes for 2004 were lower than the same period in 2003 primarily due to the cessation of interest capitalization upon the return to service of Units 3 and 4. Operating costs for 2004 were $35 per MWh compared to $36 per MWh for the period February 14 to December 31, 2003. Average realized prices in 2004 were $47 per MWh compared to $48 per MWh during TransCanada's period of ownership in 2003. Approximately 52 per cent of Bruce Power's output in 2004 was sold into Ontario's wholesale spot market.

TransCanada has not made any cash contributions to, and has not received any cash distributions from, Bruce Power subsequent to the acquisition of the company's ownership interest in February 2003.

Equity income from Bruce Power is directly impacted by fluctuations in wholesale spot market prices for electricity as well as overall plant availability which, in turn, is impacted by scheduled and unscheduled maintenance. To reduce its exposure to spot market prices, Bruce Power has entered into fixed price sales contracts for approximately 36 per cent of planned output for 2005. Bruce Power's operating expenses in 2005 are expected to increase from 2004 due to higher depreciation and amortization on the Bruce A units, higher outage costs and higher fuel costs.

The average availability in 2005 is expected to be 85 per cent compared to 82 per cent achieved in 2004. Unit 3 began its first planned maintenance outage on January 8, 2005 and is expected to be offline for approximately two months. Unit 4 is scheduled to go offline later in first quarter 2005 for a similar inspection program. Maintenance outages of approximately two to three months each are also planned for two other units in 2005. One outage is expected to begin in second quarter 2005 and the other outage is expected to begin in third quarter 2005.

Power LP Investment Power LP Investment includes the earnings generated from TransCanada's 30.6 per cent investment in Power LP, which is one of Canada's largest publicly-held, power-based income funds. Power LP owns 11 power plants, eight in Canada and three in the U.S., that are hydroelectric or fuelled by natural gas, waste heat, wood waste or a combination thereof. Power LP increased its generating capacity in 2004 from 328 MW to 744 MW through the acquisition of four power facilities, Curtis Palmer and ManChief from TransCanada and Mamquam and Queen Charlotte through the acquisition of Hydro Investment Corporation.

TransCanada's investment in Power LP decreased in 2004 from 35.6 per cent to 30.6 per cent. In 2004, Power LP issued 8.1 million subscription receipts to partially finance the purchase of the Curtis Palmer and ManChief power generation facilities from TransCanada. TransCanada purchased 540,000 of these subscription receipts for $20 million. All of the subscription receipts were converted to limited partnership units on April 30, 2004 upon Power LP's acquisition of the Curtis Palmer and ManChief facilities, thereby reducing TransCanada's ownership of the partnership to 30.6 per cent. TransCanada continues to be the largest unitholder and the manager of Power LP, owning approximately 14.5 million units at December 31, 2004.

TransCanada is the manager of Power LP and its power plant operations. In this capacity, TransCanada manages the operations and maintenance requirements of all Power LP plants, the fuel supply and associated price exposure and, when market conditions warrant, enhances the overall operating profits of Power LP (i.e. by curtailing certain plants during off-peak hours and selling the displaced natural gas at attractive market prices), resulting in increased overall net earnings for Power LP and maximized investment value for unitholders, including TransCanada.

Operating and other income from the investment in Power LP of $29 million for 2004 was $6 million lower compared to 2003. Additional earnings from Power LP's April 2004 acquisition of the Curtis Palmer and ManChief facilities were more than offset by the impact of TransCanada's reduced ownership interest in Power LP and the recognition of $132 million of previously deferred gains resulting from the removal of the Power LP redemption obligation. Prior to the removal of the redemption obligation, TransCanada was recognizing into income the amortization of these deferred gains over a period through to 2017.

The cash distributions to TransCanada from Power LP in 2004 were approximately $36 million compared to $35 million in 2003. At December 31, 2004, Power LP units closed at $35.40 on the Toronto Stock Exchange.

POWER SALES VOLUMES AND PLANT AVAILABILITY

Power Sales Volumes

(GWh)	**2004**	2003	2002
Western operations (1)	**11,695**	12,296	12,065
Eastern operations (1)	**6,198**	6,906	5,630
Bruce Power investment (2)	**10,608**	6,655	
Power LP investment (1) (3)	**2,419**	2,153	2,416
Total	**30,920**	28,010	20,111

(1) ManChief and Curtis Palmer are included in Power LP Investment, effective April 30, 2004.

(2) Acquired on February 14, 2003. Sales volumes in 2003 reflect TransCanada's 31.6 per cent share of Bruce Power output from the date of acquisition.

(3) At December 31, 2004, TransCanada operated and managed Power LP and held a 30.6 per cent ownership interest in Power LP. The volumes in the table represent 100 per cent of Power LP's sales volumes.

Power sales volumes increased 10 per cent in 2004 to 30,920 GWh compared to 28,010 GWh in 2003 primarily due to TransCanada's full year of ownership in Bruce Power, in addition to the restart of Bruce Power Units 3 and 4.

Sales volumes for Western Operations were lower in 2004 compared to 2003 due to the sale of ManChief to Power LP in April 2004, and lower portfolio management trading activity, partially offset by new volumes from the MacKay River plant placed in-service in 2004. Eastern Operations' sales volumes decreased in 2004 compared to 2003 primarily as a result of the sale of Curtis Palmer to Power LP in April 2004, lower utilization of OSP and a reduction in contract volumes due to lower demand. Sales volumes for the Bruce Power investment increased by 59 per cent as a result of the restart of Bruce Power Units 3 and 4 and TransCanada's full year of ownership in 2004 partially offset by decreased plant availability. Volumes for Power LP increased due to the purchase of Curtis Palmer and ManChief in April 2004 and Mamquam and Queen Charlotte in July 2004.

Weighted Average Plant Availability (1)

	2004	2003	2002
Western operations (2)	**95%**	93%	99%
Eastern operations (2)	**95%**	94%	95%
Bruce Power investment (3)	**82%**	83%	
Power LP investment (2)	**97%**	96%	94%
All plants, excluding Bruce Power investment	**96%**	94%	96%
All plants	**90%**	90%	96%

(1) 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.
(2) ManChief and Curtis Palmer are included in Power LP Investment effective April 30, 2004.
(3) The comparative 2003 percentage is calculated from the February 14, 2003 date of acquisition. Unit 4 is included effective November 1, 2003 and Unit 3 is included effective March 1, 2004.

POWER – OPPORTUNITIES AND DEVELOPMENTS

TransCanada is committed to develop, acquire, own and operate the lowest-cost power sources or have facilities with secure long-term contracts in markets it knows. TransCanada seeks to build or acquire low-cost, base-load facilities with low operating costs and high reliability. TransCanada seeks to avoid high-cost facilities that sell into volatile merchant markets without long-term contracts. Power intends to execute its strategy by:

- Focusing on markets and regions where it has a competitive advantage – primarily Western Canada and the Northwestern U.S., and Eastern Canada and the Northeastern U.S.
- Focusing on low-cost, base-load generation.
- Focusing on new projects underpinned by secure long-term contracts.
- Structuring deals to keep risks low.
- Using solid disciplined marketing and trading operations to sell power that is not contracted and optimize and protect power-generation cash flows.

In fourth quarter 2004, TransCanada announced that it will purchase hydroelectric generation assets from USGen with a total generating capacity of 567 MW for US$505 million. The purchase is subject to the sale of the 49 MW Bellows Falls hydroelectric facility to Vermont Hydroelectric, which exercised its pre-existing option to purchase the facility. This would result in a US$72 million reduction in purchase price to US$433 million for generating capacity of 518 MW. All bankruptcy court approvals have been granted for TransCanada's USGen acquisition. However, other regulatory approvals and conditions will need to be met prior to closing. The transaction is expected to close in the first half of 2005.

Cartier Wind, owned 62 per cent by TransCanada, announced in fourth quarter 2004 it was awarded six wind energy projects in Québec by Hydro-Québec representing a total of 739.5 MW. The six projects are expected to be commissioned between 2006 and 2012 and are expected to cost a total of more than $1.1 billion. Long-term electricity supply contracts with Hydro-Québec for each of the six facilities were executed on February 25, 2005.

Construction of the 550 MW Bécancour natural gas-fired cogeneration power plant in Québec began in third quarter 2004, to be in-service in late 2006. In mid-2003, TransCanada announced its plans to develop the power plant which is located in the Bécancour Industrial Park, near Trois-Rivières. The entire power output will be supplied to Hydro-Québec under a 20 year power purchase contract. The plant will also supply steam to certain major businesses located within the industrial park.

Late in fourth quarter 2004, TransCanada responded to the Ontario government's Request For Proposals for 2,500 MWs of new electricity generation capacity, of which Portlands Energy Centre L.P. (Portlands Energy) was one of the submitted projects by TransCanada. Portlands Energy is a 550 MW natural gas-fuelled facility in downtown Toronto and would be developed through a partnership with OPG.

Following the successful restart of Bruce A Units 3 and 4, Bruce Power began conducting a technical review to assess the feasibility of refurbishing Bruce A Units 1 and 2. Units 1 and 2 were laid-up in 1995 and 1997, respectively. Information has been gathered to evaluate the condition of the units to fully understand the project scope and cost, and environmental assessment of the project continues to be performed. In September 2004, the province of Ontario appointed a special negotiator to work with Bruce Power to negotiate an agreement for additional electricity supply. While no decision has been finalized with respect to the refurbishment of Units 1 and 2, the return to service of these units would be a significant step towards satisfying the province of Ontario's future energy requirements. This technical review will also establish improvements that will be required to extend the lives of the six operating units which are scheduled to be taken out of service over the next 15 years. In 2004, Bruce Power expensed $16 million related to this project.

TransCanada, together with its Bruce Power partners, is evaluating a potential investment in the Point Lepreau nuclear generating station in New Brunswick. Point Lepreau, which is indirectly owned by the New Brunswick provincial government, is a 680 MW nuclear power plant with a CANDU reactor similar to the Bruce reactors in Ontario. No decision has been made by TransCanada and its partners as to whether Bruce Power will proceed with investment in the Point Lepreau facility. Discussions are ongoing with New Brunswick Power.

POWER – BUSINESS RISKS

Plant Availability Maintaining plant availability is critical to the continued success of the Power business and this risk is mitigated through a commitment to an operational excellence model that provides low-cost, reliable operating performance at each of the company's operated power plants. This same commitment to operational excellence will be applied in 2005 and future years. However, unexpected plant outages and/or the duration of outages may require purchases at market prices to enable TransCanada to meet the company's contractual power supply obligations and/or increase maintenance costs.

Fluctuating Market Prices TransCanada operates in highly competitive, deregulated power markets. Volatility in electricity prices is caused by market factors such as power plant fuel costs, fluctuating supply and market demand which are greatly affected by weather, power consumption and plant availability. TransCanada manages these inherent market risks through:

- long-term purchase and sales contracts for both electricity and plant fuels;
- control of generation output;
- matching physical plant contracts or PPA supply with customer demand;
- fee-for-service managed accounts rather than direct commodity exposure; and
- the company's overall risk management program with respect to general market and counterparty risks.

The company's risk management practices are described further in the section on Risk Management. TransCanada's largest exposure to sales price fluctuations is on Bruce Power's uncontracted volumes. See the section below "Power – Business Risks – Uncontracted Volumes".

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, 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.

Weather Temperature and weather events may create power and gas demand and price volatility, and may also impact the ability to transmit power to markets. Seasonal changes in temperature also affect the efficiency and output capability of natural gas-fired power plants.

Hydrology Power is subject to hydrology risk with its ownership, directly and indirectly, of hydroelectric power generation facilities. Weather changes, local river management and potential dam failures at these plants or upstream plants pose potential risks to the company.

Uncontracted Volumes Although TransCanada seeks to secure sales under medium- to long-term contracts, TransCanada retains an amount of unsold generation in the short term in order to provide flexibility in managing the company's portfolio of owned assets. Bruce Power has a significant amount of its uncontracted volumes sold into the Ontario wholesale spot market. The sale of this power in the open market is subject to market price volatility which directly impacts earnings.

POWER – OTHER

Operational Excellence TransCanada is committed to its operational excellence model to provide low cost, reliable operating performance at each of its plants in an effort to achieve and sustain high performance as measured against broad industry standards. Weighted average plant availability, excluding Bruce Power, averaged 96 per cent in 2004, exceeding the comparative industry average of 90 per cent. Forced outage rates (unplanned outages) in 2004 were 1.6 per cent as compared to a comparative industry average of 5.5 per cent.

POWER – OUTLOOK

Contributions from Eastern Operations are expected to be lower in 2005 due to higher natural gas costs at OSP resulting from the 2004 arbitration decision, no earnings in 2005 from Curtis Palmer as a result of its sale to Power LP in April 2004, the expiration of long-term contracts held by TCPM at the end of 2004 and the expected non-recurrence of earnings recognized from the Boston Edison transaction in 2004. Partially offsetting these reductions are earnings from Grandview and the USGen acquisition expected to close in the first half of 2005. Should the fourth arbitration decision at OSP, expected in 2005, result in a continued pricing mechanism for fuel gas in excess of market price and if anticipated market conditions do not change substantially, management expects there could be an asset impairment write-down of this facility. The net carrying value of OSP at December 31, 2004 was approximately US$150 million.

Bruce Power earnings are subject to potential variability as a result of prices realized, plant availability and operating expense levels. A $1.00 per MWh change in the spot price for electricity in Ontario would change TransCanada's after-tax equity income from Bruce Power by approximately $5 million. The average availability of Bruce Power in 2005 is expected to be 85 per cent compared to 82 per cent in 2004. Bruce Power operating expenses are expected to increase in 2005 due to higher outage costs, higher depreciation on the Bruce A units and recent capital programs, and higher fuel costs.

Earnings opportunities in Power may be affected by factors such as plant availability, fluctuating market prices for power and gas and ultimately market heat rates, regulatory changes, weather, sales of uncontracted volumes, currency movements and overall stability of the power industry. Please see "Power – Business Risks" for a complete discussion of these factors.

CORPORATE

HIGHLIGHTS

Net Expenses Net expenses in 2004 decreased $39 million compared to 2003.

Corporate Results-at-a-Glance

Year ended December 31 (millions of dollars)	**2004**	2003	2002
Indirect financial and preferred equity charges	**79**	89	91
Interest income and other	**(34)**	(21)	(14)
Income taxes	**(43)**	(27)	(25)
Net expenses, after tax	**2**	41	52

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

- **Indirect Financial and Preferred Equity Charges** 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 the Corporate segment. These costs are directly impacted by the amount of debt TransCanada maintains and the degree to which TransCanada is impacted by fluctuations in interest rates and foreign exchange.
- **Interest Income and Other** Interest income is earned on invested cash balances. Gains and losses on foreign exchange related to working capital in the Corporate segment are included in interest income and other.

Net expenses, after tax, in the Corporate segment were $2 million in 2004 compared to $41 million in 2003 and $52 million in 2002.

The decrease in net expenses in 2004 from 2003 was primarily due to the positive impacts of income tax related items, including refunds received and the recognition of income tax benefits relating to additional loss carryforwards utilized, the release in 2004 of previously established restructuring provisions and positive impacts of foreign exchange related items.

The decrease in net expenses in 2003 from 2002 was primarily due to the positive impacts of a weaker U.S. dollar compared to the prior year.

In 2005, the Corporate segment is expected to incur a more normalized level of net expenses with higher net expenses than in 2004.

LIQUIDITY AND CAPITAL RESOURCES

HIGHLIGHTS

Investing Activities Total capital expenditures and acquisitions, including assumed debt, were approximately $4.7 billion over the past three years.

Dividend TransCanada's Board of Directors has increased quarterly common share dividend payments for the past five consecutive years, including a 5.2 per cent increase to $0.305 per share from $0.29 per share for the quarter ending March 31, 2005.

Funds Generated from Continuing Operations
Funds generated from continuing operations were approximately $1.7 billion for 2004 compared to approximately $1.8 billion for both 2003 and 2002. The decrease in 2004 was mainly as a result of higher current income tax expenses in 2004 compared to the two prior years. The Gas Transmission business was the primary source of funds generated from operations for each of the three years. As a result of rapid growth in the Power business in the last few years, the Power segment's funds from operations increased in 2004 compared to the two prior years.

At December 31, 2004, 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 the past few years.

Investing Activities Capital expenditures, excluding acquisitions, totalled $476 million in 2004 compared to $391 million and $599 million in 2003 and 2002, respectively. Expenditures in all three years related primarily to maintenance and capacity capital in TransCanada's Gas Transmission business and construction of new power plants in Canada.

During 2004, TransCanada acquired GTN for approximately US$1.2 billion, excluding assumed debt of approximately US$0.5 billion, and sold the ManChief and Curtis Palmer power facilities for US$402.6 million, excluding closing adjustments.

During 2003, TransCanada acquired a 31.6 per cent interest in Bruce Power for $409 million, the remaining interests in Foothills previously not held by the company for $105 million, excluding assumed debt of $154 million, and increased its interest in Portland to 61.7 per cent from 33.3 per cent for US$51 million, excluding assumed debt of US$78 million.

During 2002, TransCanada acquired the ManChief power plant for $209 million and a general partnership interest in Northern Border Partners, L.P. for $19 million.

Financing Activities In 2004, TransCanada retired long-term debt of $997 million. The company issued $200 million of 4.10 per cent medium-term notes due 2009, US$350 million of 5.60 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.

In 2003, TransCanada repaid long-term debt of $744 million, reduced notes payable by $62 million and redeemed all of its outstanding US$160 million, 8.75 per cent Junior Subordinated Debentures. The company issued $450 million of ten year, 5.65 per cent medium-term notes and US$350 million of ten year, 4.00 per cent senior unsecured notes.

In 2002, the company funded long-term debt maturities of $486 million and reduced notes payable by $46 million.

Dividends and preferred securities charges amounting to $623 million were paid in 2004 compared to $588 million in 2003 and $546 million in 2002.

In February 2005, TransCanada's Board of Directors approved an increase in the quarterly common share dividend payment to $0.305 per share from $0.29 per share for the quarter ending March 31, 2005. This was the fifth consecutive year of dividend increase since the $0.20 per share declared in fourth quarter 2000.

Financing activities include a net increase in TransCanada's proportionate share of non-recourse debt of joint ventures of $120 million in 2004 compared to net reductions of $11 million in 2003 and $36 million in 2002.

Credit Activities In December 2004, TCPL renewed shelf prospectuses that qualified for issuance $1.5 billion of medium-term notes in Canada and US$1 billion of debt securities in the U.S. In January 2005, $300 million of 5.10 per cent medium-term notes due 2017 were issued under the Canadian shelf prospectus.

At December 31, 2004, total credit facilities of $2.0 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 syndicated credit facility established in December 2002. This facility is comprised of a $1.0 billion tranche with a five-year term and a $500 million tranche with a 364-day term with a two year term out option. Both tranches are extendible on an annual basis and are revolving unless during a term out period. Both tranches were extended in December 2004: the $1.0 billion tranche to December 2009 and the $500 million tranche to December 2005. The remaining amounts are either demand or non-extendible facilities.

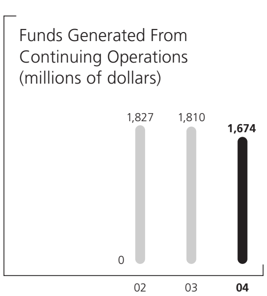
At December 31, 2004, TransCanada had used approximately $61 million of its total lines of credit for letters of credit and to support ongoing commercial arrangements. If drawn, interest on the lines of credit would be charged at prime rates of Canadian chartered and U.S. banks or at other negotiated financial bases.

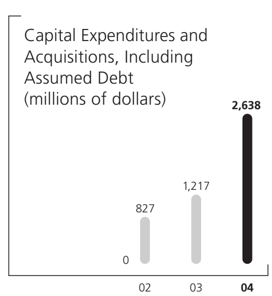
Credit ratings on TCPL's senior unsecured debt assigned by Dominion Bond Rating Service Limited (DBRS), Moody's Investors Service (Moody's) and Standard & Poor's are currently A, A2 and A-, respectively. DBRS and Moody's both maintain a 'stable' outlook on their ratings and Standard & Poor's maintains a 'negative' outlook on its rating.

CONTRACTUAL OBLIGATIONS

Obligations and Commitments Total long-term debt at December 31, 2004 was approximately $10.5 billion compared to approximately $10.0 billion at December 31, 2003. TransCanada's share of total non-recourse debt of joint ventures at December 31, 2004 was $862 million compared to $780 million at December 31, 2003. Total notes payable, including the proportionate share of joint ventures, at December 31, 2004 were $546 million compared to $367 million at December 31, 2003. The debt and notes payable of joint ventures are non-recourse to TransCanada. The security provided by each joint venture is limited to the rights and assets of that joint venture and do not extend to the rights and assets of TransCanada, except to the extent of TransCanada's investment.

Effective January 1, 2005, under new Canadian accounting standards, the non-controlling interest component of preferred securities, amounting to $670 million at December 31, 2004, will be classified as debt.





At December 31, 2004, principal repayments related to long-term debt and the company's proportionate share of the non-recourse debt of joint ventures are as follows.

Principal Repayments

Year ended December 31 (millions of dollars)	2005	2006	2007	2008	2009	2010+
Long-term debt	766	387	615	545	753	7,413
Non-recourse debt of joint ventures	83	49	18	18	141	553
Total principal repayments	849	436	633	563	894	7,966

At December 31, 2004, future annual payments, net of sub-lease receipts, under the company's operating leases for various premises and a natural gas storage facility are approximately as follows.

Operating Lease Payments

Year ended December 31 (millions of dollars)	2005	2006	2007	2008	2009	2010+
Minimum lease payments	37	45	51	53	53	697
Amounts recoverable under sub-leases	(9)	(10)	(9)	(9)	(9)	(21)
Net payments	28	35	42	44	44	676

The operating lease agreements for premises expire at various dates through 2011, with an option to renew certain lease agreements for 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, 2004, the company's future purchase obligations are approximately as follows.

Purchase Obligations (1)

Year ended December 31 (millions of dollars)	2005	2006	2007	2008	2009	2010+
Gas Transmission						
Transportation by others (2)	186	177	142	121	82	198
Other	94	46	42	40	2	3
Power						
Commodity purchases (3)	429	255	259	266	277	2,658
Capital expenditures (4)	288	70	–	–	–	–
Other (5)	93	100	89	84	88	223
Corporate						
Information technology and other	9	9	7	7	7	–
Total purchase obligations	1,099	657	539	518	456	3,082

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

(2) Rates are based on known 2005 levels. Beyond 2005, 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) Amounts are estimates and are subject to variability based on timing of construction and project enhancements.

(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 2005, TransCanada expects to make funding contributions to the company's pension plans and other benefit plans in the amount of approximately $67 million and $6 million, respectively. The expected decrease in total funding in 2005 from $88 million in 2004 is due to investment performance above long-term expectations in 2004 partially offset by continued reductions in discount rates used to calculate plan obligations.

On June 18, 2003, the Mackenzie Delta gas producers, the APG and TransCanada reached an agreement which governs TransCanada's role in the Mackenzie Gas Pipeline 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. This share is currently estimated to be approximately $90 million. As at December 31, 2004, TransCanada had funded $60 million of this loan (2003 – $34 million) which is included in other assets on the balance sheet. The ability to recover this investment is dependent upon the outcome of the project.

TransCanada had a $50 million operating line of credit to Power LP, available on a revolving basis. In August 2004, the amount borrowed against this line of credit was fully repaid by Power LP and the operating line of credit was terminated.

At December 31, 2004, TransCanada held a 33.4 per cent interest in TC PipeLines, LP which is a publicly-held limited partnership. On May 28, 2003, TC PipeLines, LP renewed its US$40 million unsecured two-year revolving credit facility with TransCanada. At December 31, 2004, the partnership had US$6.5 million outstanding under this credit facility (December 31, 2003 – nil).

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.

Guarantees TransCanada had no outstanding guarantees related to the long-term debt of unrelated third parties at December 31, 2004.

Upon acquisition of Bruce Power, the company, together with Cameco and BPC Generation Infrastructure Trust, guaranteed on a several pro-rata basis certain contingent financial obligations of Bruce Power related to operator licenses, the lease agreement, power sales agreements and contractor services. TransCanada's share of the net exposure under these guarantees at December 31, 2004 was estimated to be approximately $158 million of a maximum of $293 million. The terms of the guarantees range from 2005 to 2018. The current carrying amount of the liability related to these guarantees is nil and the fair value is approximately $9 million.

TransCanada has guaranteed the equity undertaking of a subsidiary which supports the payment, under certain conditions, of principal and interest on US$161 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. The escrowed funds represent the full face amount of the potential liability under certain GTN guarantees and are to be used to satisfy the liability under these designated guarantees.

Contingencies The Canadian Alliance of Pipeline Landowners' Associations 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. The company believes 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, including amounts in foreign currencies, purchases and sells energy commodities and invests in foreign operations. These activities result in exposures to interest rates, energy commodity prices and foreign currency exchange rates. The company utilizes derivative and other financial instruments to manage its exposure to the risks that result from these activities.

A derivative must be designated and effective to be accounted for as a hedge. Gains or losses relating to derivatives that are hedges are deferred and recognized in the same period and in the same financial statement category as the corresponding hedged transactions. The recognition of gains and losses on derivatives used as hedges for Canadian Mainline, Alberta System, GTN and the Foothills System exposures is determined through the regulatory process.

The carrying amounts of derivatives, which hedge the price risk of foreign currency denominated assets and liabilities of self-sustaining foreign operations, are recorded on the balance sheet at their fair value. Gains and losses on these derivatives, realized and unrealized, are included in the foreign exchange adjustment account in Shareholders' Equity as an offset to the corresponding gains and losses on the translation of the assets and liabilities of the foreign subsidiaries. As of January 1, 2004, carrying amounts for interest rate swaps are recorded on the balance sheet at their fair value. Foreign currency transactions hedged by foreign exchange contracts are recorded at the contract rate. Power, natural gas and heat rate derivatives are recorded on the balance sheet at their fair value.

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

Notional principal amounts are not recorded in the financial statements because these amounts are not exchanged by the company and its counterparties and are not a measure of the company's exposure. Notional amounts are used only as the basis for calculating payments for certain derivatives.

Foreign Investments At December 31, 2004 and 2003, the company had foreign currency denominated assets and liabilities which created an exposure to changes in exchange rates. The company uses foreign currency derivatives to hedge this net exposure on an after-tax basis. The foreign currency derivatives have a floating interest rate exposure which the company partially hedges by entering into interest rate swaps and forward rate agreements. The fair values shown in the table below for those derivatives that have been designated as and are effective as hedges for foreign exchange risk are offset by translation gains or losses on the net assets and are recorded in the foreign exchange adjustment account in Shareholders' Equity.

Net Investment in Foreign Assets

Asset/(Liability) December 31 (millions of dollars)	Accounting Treatment	2004 Fair Value	2004 Notional or Principal Amount (U.S.)	2003 Fair Value	2003 Notional or Principal Amount (U.S.)
U.S. dollar cross-currency swaps (maturing 2006 to 2009)	Hedge	**95**	**400**	65	250
U.S. dollar forward foreign exchange contracts (maturing 2005)	Hedge	**(1)**	**305**	3	125
U.S. dollar options (maturing 2005)	Non-hedge	**1**	**100**	–	–

In accordance with the company's accounting policy, each of the above derivatives is recorded on the consolidated balance sheet at its fair value in 2004. For derivatives that have been designated as and are effective as hedges of the net investment in foreign operations, the offsetting amounts are included in the foreign exchange adjustment account.

In addition, at December 31, 2004, the company had interest rate swaps associated with the cross-currency swaps with notional principal amounts of $375 million (2003 – $311 million) and US$250 million (2003 – US$200 million). The carrying amount and fair value of these interest rate swaps was $4 million (2003 – $3 million) and $4 million (2003 – $1 million), respectively.

Reconciliation of Foreign Exchange Adjustment Gains/(Losses)

December 31 (millions of dollars)	2004	2003
Balance at beginning of year	**(40)**	14
Translation losses on foreign currency denominated net assets	**(64)**	(136)
Foreign exchange gains on derivatives, net of income taxes	**33**	82
	(71)	(40)

Foreign Exchange Gains/(Losses) Foreign exchange gains/(losses) included in Other Expenses/(Income) for the year ended December 31, 2004 are $4 million (2003 – nil; 2002 – $(11) million).

Foreign Exchange and Interest Rate Management Activity The company manages certain of the foreign exchange risks of U.S. dollar debt, U.S. dollar expenses and the interest rate exposures of the Canadian Mainline, the Alberta System, GTN and the Foothills 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)		**2004**		2003	
December 31 (millions of dollars)	Accounting Treatment	**Fair Value**	**Notional or Principal Amount**	Fair Value	Notional or Principal Amount
Foreign Exchange					
Cross-currency swaps					
(maturing 2010 to 2012)	Hedge	**(39)**	**U.S. 157**	(26)	U.S. 282
Interest Rate					
Interest rate swaps					
Canadian dollars					
(maturing 2005 to 2008)	Hedge	**7**	**145**	(1)	340
(maturing 2006 to 2009)	Non-hedge	**9**	**374**	10	624
		16		9	
U.S. dollars					
(maturing 2010 to 2015)	Hedge	**(2)**	**U.S. 275**	11	U.S. 50
(maturing 2007 to 2009)	Non-hedge	**7**	**U.S. 100**	(3)	U.S. 50
		5		8	

In accordance with the company's accounting policy, each of the above derivatives is recorded on the consolidated balance sheet at its fair value in 2004. At December 31, 2004, the company also had interest rate swaps associated with the cross-currency swaps with notional principal amounts of $227 million (2003 – $390 million) and US$157 million (2003 – US$282 million). The carrying amount and fair value of these interest rate swaps was $(4) million (2003 – nil) and $(4) million (2003 – $6 million), respectively.

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)		**2004**		2003	
December 31 (millions of dollars)	Accounting Treatment	**Fair Value**	**Notional or Principal Amount**	Fair Value	Notional or Principal Amount
Foreign Exchange					
Options (maturing 2005)	Non-hedge	**2**	**U.S. 225**	1	U.S. 25
Forward foreign exchange contracts (maturing 2005)	Non-hedge	**1**	**U.S. 29**	1	U.S. 19
Cross-currency swaps (maturing 2013)	Hedge	**(16)**	**U.S. 100**	(7)	U.S. 100
Interest Rate					
Options (maturing 2005)	Non-hedge	**–**	**U.S. 50**	(2)	U.S. 50
Interest rate swaps					
Canadian dollar					
(maturing 2007 to 2009)	Hedge	**4**	**100**	2	50
(maturing 2005 to 2011)	Non-hedge	**1**	**110**	2	100
		5		4	
U.S. dollar					
(maturing 2006 to 2013)	Hedge	**5**	**U.S. 100**	40	U.S. 250
(maturing 2006 to 2010)	Non-hedge	**22**	**U.S. 250**	(3)	U.S. 200
		27		37	

In accordance with the company's accounting policy, each of the above derivatives is recorded on the consolidated balance sheet at its fair value in 2004. At December 31, 2004, the company also had interest rate swaps associated with the cross-currency swaps with notional principal amounts of $136 million (2003 – $136 million) and US$100 million (2003 – US$100 million). The carrying amount and fair value of these interest rate swaps was $(10) million (2003 – nil) and $(10) million (2003 – $(7) million), respectively.

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, 2004 was $1 million (2003 – $(1) million).

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 values and notional volumes of the swap, option, forward and heat rate contracts are shown in the tables below. In accordance with the company's accounting policy, each of the derivatives in the table below is recorded on the balance sheet at its fair value in 2004 and 2003.

Power

Asset/(Liability) December 31 (millions of dollars)	Accounting Treatment	**2004** **Fair Value**	2003 Fair Value
Power – swaps			
(maturing 2005 to 2011)	Hedge	**7**	(5)
(maturing 2005)	Non-hedge	**(2)**	–
Gas – swaps, forwards and options			
(maturing 2005 to 2016)	Hedge	**(39)**	(34)
(maturing 2005)	Non-hedge	**(2)**	(1)
Heat rate contracts			
(maturing 2005 to 2006)	Hedge	**(1)**	(1)

Notional Volumes		**Power (GWh)**		**Gas (Bcf)**	
December 31, 2004	Accounting Treatment	**Purchases**	**Sales**	**Purchases**	**Sales**
Power – swaps					
(maturing 2005 to 2011)	Hedge	**3,314**	**7,029**	**–**	**–**
(maturing 2005)	Non-hedge	**438**	**–**	**–**	**–**
Gas – swaps, forwards and options					
(maturing 2005 to 2016)	Hedge	**–**	**–**	**80**	**84**
(maturing 2005)	Non-hedge	**–**	**–**	**5**	**8**
Heat rate contracts					
(maturing 2005 to 2006)	Hedge	**–**	**229**	**2**	**–**
December 31, 2003					
Power – swaps	Hedge	1,331	4,787	–	–
	Non-hedge	59	77	–	–
Gas – swaps, forwards and options	Hedge	–	–	79	81
	Non-hedge	–	–	–	7
Heat rate contracts	Hedge	–	735	1	–

U.S. Dollar Transaction Hedges To reduce risk and protect margins when purchase and sale contracts are denominated in different currencies, the company may enter into forward foreign exchange contracts and foreign exchange options which establish the foreign exchange rate for the cash flows from the related purchase and sale transactions.

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 risk exposures in accordance with the company's corporate market risk policies and position limits. The company's primary market 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 14 to the consolidated financial statements.

Risks and Risk Management Related to the Kyoto Protocol TransCanada believes that the natural gas that is transported and the electricity that is generated by its facilities play a critical role in meeting continental energy demand. The company also recognizes, however, that its facilities produce emissions that can also contribute to climate change and air related issues. For this reason, the management of air emissions and climate change issues is a key area of the company's environmental stewardship work.

Climate change policy development is well under way in North America. In December 2002, the Canadian government registered its instrument of ratification with the United Nations, making Canada the 100th country to ratify the Kyoto Protocol. Following ratification, the federal government initiated discussions with industry regarding emissions reductions from sources in three broad categories: the oil and gas sector, the electricity sector and the mining/manufacturing sector. The mechanism that is proposed for achieving the reduction is a domestic emissions trading system that would cap emissions from sectors at predetermined emissions intensity levels.

As direct emitters of greenhouse gas emissions, TransCanada's facilities will be impacted by climate change policy developments in Canada. The fossil-fired power plants, pipeline systems and carbon black facilities are expected to be captured under the proposed federal government plan for industrial emitters. At present, however, the details of the target allocation within sectors and allowable compliance options have not been finalized. Until the allocation of targets within the sector are set and until compliance options are fully developed, it is difficult to determine the level of impact to the company's Canadian asset base.

Over the next year, TransCanada will continue to participate in climate change policy discussions in the jurisdictions where the company has assets and business interests. Climate change is a strategic issue for TransCanada and management of this important environmental concern has been ongoing for several years. TransCanada has a comprehensive climate change strategy in place that includes five key areas of activities:

- participation in policy forums;
- implementation of direct emissions reduction programs;
- assessment of new technology;
- evaluation of emissions trading mechanisms; and
- assessment of business opportunities.

Activities are ongoing in each of these areas and the company is committed to sharing its progress on key activities publicly. Over the past several years, TransCanada has documented its technical activities and research and development work in yearly reports to Canada's Climate Change Voluntary Challenge & Registry Inc. The Canadian government has legislated mandatory greenhouse gas emissions reporting beginning in 2005. TransCanada will continue to report on the activities that are under way to manage greenhouse gas emissions.

Disclosure Controls and Procedures and Internal Controls Pursuant to regulations adopted by the U.S. Securities and Exchange Commission (SEC), under the Sarbanes-Oxley Act of 2002, TransCanada's management evaluates the effectiveness of the design and operation of the company's disclosure controls and procedures (disclosure controls). This evaluation is done under the supervision of, and with the participation of, the President and Chief Executive Officer and the Chief Financial Officer.

As of the end of the period covered by this Annual Report, TransCanada's management evaluated the effectiveness of its disclosure controls. Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer have concluded that TransCanada's disclosure controls are effective in ensuring that material information relating to TransCanada is made known to management on a timely basis, and is included in this Annual Report.

To the best of these officers' knowledge and belief, there have been no significant changes in internal controls over financial reporting or in other factors that could significantly affect internal controls over financial reporting subsequent to the date on which such evaluation was completed in connection with this Annual Report.

CEO and CFO Certifications With respect to the year ending December 31, 2004, TransCanada's President and Chief Executive Officer has provided the New York Stock Exchange 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 certifications regarding the quality of TransCanada's public disclosures relating to its fiscal 2004 reports filed with the SEC.

CRITICAL ACCOUNTING POLICY

The company accounts for the impacts of rate regulation in accordance with generally accepted accounting principles (GAAP) as outlined in Note 1 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. The most significant example of this relates to the recording of income taxes on the taxes payable basis as outlined in Note 15 to the consolidated financial statements.

CRITICAL ACCOUNTING ESTIMATE

Since a determination 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. TransCanada's critical accounting estimate is depreciation expense. TransCanada's plant, property and equipment are depreciated on a straight-line basis over their estimated useful lives. Depreciation expense for the year ended December 31, 2004 was $945 million. Depreciation expense impacts the Gas Transmission and Power segments of the company. In the Gas Transmission business, depreciation rates are approved by the regulators and 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 Gas Transmission 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.

In 2004, TransCanada recognized in income the remaining amount related to the critical accounting estimate of the after-tax deferred gain recorded on the 2001 sale of the Gas Marketing business, which is further described in Discontinued Operations.

ACCOUNTING CHANGES

Asset Retirement Obligations In January 2003, the Canadian Institute of Chartered Accountants (CICA) issued a new Handbook Section "Asset Retirement Obligations". The new section focuses on the recognition and measurement of liabilities for obligations associated with the retirement of property, plant and equipment when those obligations result from the acquisition, construction, development or normal operation of the assets. The section requires that the fair value of a liability for an asset retirement obligation be recognized 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. The liability is accreted at the end of each period through charges to operating expenses. This section was effective for TransCanada as of January 1, 2004 and was applied retroactively with restatement of prior periods. See Note 2 to the consolidated financial statements for the impact of this accounting change.

Hedging Relationships Effective January 1, 2004, the company adopted the provisions of the CICA's new Accounting Guideline "Hedging Relationships" that specifies the circumstances in which hedge accounting is appropriate, including the identification, documentation, designation and effectiveness of hedges, and the discontinuance of hedge accounting. See Note 2 to the consolidated financial statements for the impact of this accounting change.

Generally Accepted Accounting Principles Effective January 1, 2004, the company adopted the new Handbook Section "Generally Accepted Accounting Principles" which establishes standards for financial reporting in accordance with GAAP. It defines primary sources of GAAP and requires that an entity apply every relevant primary source, therefore eliminating the ability to rely on industry practice to support a particular accounting policy and provides an exemption for rate-regulated operations. This section was applied prospectively. See Note 2 to the consolidated financial statements for the impact of this accounting change.

General Standards of Financial Statement Presentation Effective January 1, 2004, the company adopted the new Handbook Section "General Standards of Financial Statement Presentation" which clarifies what constitutes "fair presentation in accordance with GAAP". The adoption of this section did not have an impact on the company's consolidated financial statements.

Employee Future Benefits In March 2004, the CICA amended the existing Handbook Section "Employee Future Benefits". The amendments expand the disclosure requirements for employee future benefits and are effective for fiscal years ending on or after June 30, 2004. The company adopted these provisions effective December 31, 2004. The impacts of the amendments have been included in Note 18 to the consolidated financial statements.

Impairment of Long-Lived Assets Effective January 1, 2004, the company adopted the new Handbook Section "Impairment of Long-Lived Assets". This section establishes new standards for the recognition, measurement and disclosure of the impairment of long-lived assets and establishes new write-down provisions. The adoption of this section did not have an impact on the company's consolidated financial statements.

Consolidation of Variable Interest Entities In June 2003, the Accounting Standards Board of the CICA issued a new Accounting Guideline "Consolidation of Variable Interest Entities" which requires enterprises to identify variable interest entities in which they have an interest, determine whether they are the primary beneficiary of such entities and, if so, to consolidate them. For TransCanada, the guideline's requirements are effective as of January 1, 2005. Adopting the provisions of this guideline is not expected to impact the company's consolidated financial statements.

Financial Instruments – Disclosure and Presentation In November 2004, the CICA amended the existing Handbook Section "Financial Instruments – Disclosure and Presentation" to provide guidance for classifying certain financial instruments that embody obligations that may be settled by the issuance of the issuer's equity shares as debt when the instrument that embodies the obligations does not establish an ownership relationship. This amendment is effective for fiscal years beginning on or after November 1, 2004. As a result, the non-controlling interest component of preferred securities will be classified as debt effective January 1, 2005.

DISCONTINUED OPERATIONS

TransCanada's Board of Directors approved plans in previous years to dispose of the company's International, Canadian Midstream, Gas Marketing and certain other businesses. As of December 31, 2003, TransCanada's investments in Gasoducto del Pacifico (Gas Pacifico), INNERGY Holdings S.A. (INNERGY) and P.T. Paiton Energy Company (Paiton), which were previously approved for disposal, were accounted for as part of continuing operations due to the length of time it had taken the company to dispose of these assets. Gas Pacifico and INNERGY are included in the Gas Transmission segment and Paiton is included in the Power segment. It is the intention of the company to continue with its plan to dispose of these investments.

In 2004, the company reviewed the provision for loss on discontinued operations and the after-tax deferred gain. As a result of this review, TransCanada recognized in income in 2004 the remaining $52 million of the original $102 million after-tax deferred gain.

In 2003, TransCanada recognized in income $50 million of the original $102 million after-tax deferred gain. The company's net income/(loss) from discontinued operations in 2002 was nil.

SUBSIDIARIES AND INVESTMENTS

TransCanada's subsidiaries and investments that hold significant operating assets are noted below.

Subsidiary/Investment	Major Operating Assets	Organized under the Laws of	Effective Percentage Ownership by TransCanada
TransCanada PipeLines Limited	Canadian Mainline, BC System	Canada	100
NOVA Gas Transmission Ltd.	Alberta System	Alberta	100
TransCanada Pipeline Ventures Ltd.	Ventures LP	Alberta	100
Foothills Pipe Lines Ltd.	Foothills System	Canada	100
TransCanada Pipeline USA Ltd.		Nevada	100
Gas Transmission Northwest Corporation	GTN	California	100
TransCanada Power Marketing Ltd.	U.S. power operations	Delaware	100
Great Lakes Gas Transmission Limited Partnership	Great Lakes	Delaware	50
Iroquois Gas Transmission System L.P.	Iroquois	Delaware	41
Portland Natural Gas Transmission System Partnership	Portland	Maine	61.7
TC PipeLines, LP	TC PipeLines, LP's assets	Delaware	33.4
Northern Border Pipeline Company	Northern Border	Texas	10
Tuscarora Gas Transmission Company	Tuscarora	Nevada	17.4
TransCanada Energy Ltd.	Canadian power operations	Canada	100
TransCanada Power, L.P.	Power LP assets	Ontario	30.6
Bruce Power L.P.	Bruce Power	Ontario	31.6
Trans Québec & Maritimes Pipeline Inc.	TQM	Canada	50
CrossAlta Gas Storage & Services Ltd.	CrossAlta	Alberta	60
TransGas de Occidente S.A.	TransGas	Colombia	46.5

Selected Three Year Consolidated Financial Data (1)

(millions of dollars except per share amounts)	**2004**	2003	2002
Income Statement			
Revenues	**5,107**	5,357	5,214
Net income			
Continuing operations	**980**	801	747
Discontinued operations	**52**	50	–
Total	**1,032**	851	747
Balance Sheet			
Total assets	**22,130**	20,701	20,172
Long-term debt	**9,713**	9,465	8,815
Non-recourse debt of joint ventures	**779**	761	1,222
Preferred securities	**19**	22	238
Per Common Share Data			
Net income – Basic			
Continuing operations	**$ 2.02**	$ 1.66	$ 1.56
Discontinued operations	**0.11**	0.10	–
	$ 2.13	$ 1.76	$ 1.56
Net income – Diluted			
Continuing operations	**$ 2.01**	$ 1.66	$ 1.55
Discontinued operations	**0.11**	0.10	–
	$ 2.12	$ 1.76	$ 1.55
Dividends declared	**$ 1.16**	$ 1.08	$ 1.00

(1) The selected three year 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 Note 1 and Note 21 of TransCanada's 2004 audited consolidated financial statements included in TransCanada's 2004 Annual Report.

Selected Quarterly Consolidated Financial Data (1)

(millions of dollars except per share amounts)	Fourth	Third	Second	First
2004				
Revenues	**1,394**	**1,224**	**1,256**	**1,233**
Net Income				
Continuing operations	**185**	**193**	**388**	**214**
Discontinued operations	**–**	**52**	**–**	**–**
	185	**245**	**388**	**214**
Share Statistics				
Net income per share – Basic				
Continuing operations	**$ 0.38**	**$ 0.40**	**$ 0.80**	**$ 0.44**
Discontinued operations	**–**	**0.11**	**–**	**–**
	$ 0.38	**$ 0.51**	**$ 0.80**	**$ 0.44**
Net income per share – Diluted				
Continuing operations	**$ 0.38**	**$ 0.39**	**$ 0.80**	**$ 0.44**
Discontinued operations	**–**	**0.11**	**–**	**–**
	$ 0.38	**$ 0.50**	**$ 0.80**	**$ 0.44**
Dividend declared per common share	**$ 0.29**	**$ 0.29**	**$ 0.29**	**$ 0.29**
2003				
Revenues	1,319	1,391	1,311	1,336
Net Income				
Continuing operations	193	198	202	208
Discontinued operations	–	50	–	–
	193	248	202	208
Share Statistics				
Net income per share – Basic				
Continuing operations	$ 0.40	$ 0.41	$ 0.42	$ 0.43
Discontinued operations	–	0.10	–	–
	$ 0.40	$ 0.51	$ 0.42	$ 0.43
Net income per share – Diluted				
Continuing operations	$ 0.40	$ 0.41	$ 0.42	$ 0.43
Discontinued operations	–	0.10	–	–
	$ 0.40	$ 0.51	$ 0.42	$ 0.43
Dividend declared per common share	$ 0.27	$ 0.27	$ 0.27	$ 0.27

(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 Note 1 and Note 21 of TransCanada's 2004 audited consolidated financial statements included in TransCanada's 2004 Annual Report.

Factors Impacting Quarterly Financial Information

In the Gas Transmission business, 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 earnings during any particular fiscal year remain fairly stable with fluctuations arising as a result of adjustments being recorded due to regulatory decisions and negotiated settlements with shippers and due to items outside of the normal course of operations.

In the Power business, which consists primarily of the company's investments in electrical power generation plants, 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 2004 and 2003 quarterly net earnings are as follows.

- In first quarter 2003, TransCanada completed the acquisition of a 31.6 per cent interest in Bruce Power, resulting in increased equity income in the Power business from thereon.
- Second quarter 2003 net earnings included a $19 million positive after-tax earnings impact of a June 2003 settlement with a former counterparty that had previously defaulted under power forward contracts.
- Third quarter 2003 net earnings included TransCanada's $11 million share of a positive future income tax benefit adjustment recognized by TransGas.
- First quarter 2004 net earnings included approximately $12 million of income tax refunds and related interest.
- Second quarter 2004 net earnings included gains related to Power LP of $187 million, of which $132 million were previously deferred and were being amortized into income to 2017.
- In third quarter 2004, the EUB's decisions on the GCOC and Phase I of the 2004 GRA resulted in lower earnings for the Alberta System compared to the previous quarters. In addition, third quarter 2004 included a $12 million after-tax adjustment related to the release of previously established restructuring provisions and recognition of $8 million of non-capital loss carryforwards.
- In fourth quarter 2004, TransCanada completed the acquisition of GTN, thereby recording $14 million of earnings from the November 1, 2004 acquisition date. Power recorded a $16 million pre-tax positive impact of a restructuring transaction related to power purchase contracts between OSP and Boston Edison in Eastern Operations.

FOURTH QUARTER 2004 HIGHLIGHTS

Segment Results-at-a-Glance

Three months ended December 31 (millions of dollars)	**2004**	2003
Gas Transmission	**157**	160
Power	**31**	44
Corporate	**(3)**	(11)
Net income	**185**	193

Net income and net earnings for fourth quarter 2004 for TransCanada were $185 million or $0.38 per share compared to $193 million or $0.40 per share for the same period in 2003. This decrease was primarily due to lower net earnings from the Power and Gas Transmission businesses, partially offset by lower net expenses in the Corporate segment.

Power's net earnings in fourth quarter 2004 of $31 million decreased $13 million compared to $44 million in fourth quarter 2003 primarily due to lower earnings from Western Operations and Eastern Operations. Operating and other income from Western Operations in fourth quarter 2004 of $25 million was $6 million lower compared to the $31 million earned in the same period in 2003. The decrease was mainly due to a reduction in income from ManChief following the sale of the plant to Power LP in April 2004, cumulative operating cost adjustments settled in fourth quarter 2004 at the MacKay River cogeneration plant and reduced margins resulting from lower market heat rates on uncontracted volumes.

Operating and other income from Eastern Operations in fourth quarter 2004 of $31 million was $5 million lower compared to $36 million earned in the same period in 2003. The decrease was primarily due to a reduction in income as a result of the sale of the Curtis Palmer hydroelectric facilities to Power LP in April 2004, the unfavourable impact of higher natural gas fuel costs at OSP, earnings recorded in 2003 on the Cobourg temporary generation facility and a weaker U.S. dollar in 2004 compared to 2003. Partially offsetting these reductions was a $16 million pre-tax positive impact of a restructuring transaction related to power purchase contracts between OSP and Boston Edison. In fourth quarter 2004, TransCanada closed a transaction with Boston Edison resulting in TransCanada assuming a 23.5 per cent share of the OSP power purchase contracts and recognized earnings from the effective date of April 1, 2004.

For fourth quarter 2004, Gas Transmission's net earnings were $157 million compared to $160 million in fourth quarter 2003. The $3 million decrease was due to a $5 million reduction in earnings from Wholly-Owned Pipelines, partially offset by a $2 million increase in net earnings from the Other Gas Transmission businesses. The reduction in earnings from Wholly-Owned Pipelines was primarily due to a decline in the Canadian Mainline and the Alberta System net earnings. Regulatory decisions in 2004, as well as lower returns and investment bases, resulted in lower earnings for the Canadian Mainline and the Alberta System. These decreases were partially offset by net earnings of $14 million during the quarter from TransCanada's investment in GTN which was acquired in November 2004. The increase in earnings from Other Gas Transmission was primarily due to higher earnings from CrossAlta as a result of favourable gas market storage conditions as well as higher earnings from Ventures LP. These increases were partially offset by the impact of a weaker U.S. dollar.

Net expenses, after tax, in the Corporate segment for the quarter ended December 31, 2004 were $3 million compared to $11 million for the corresponding period in 2003. The $8 million decrease in Corporate net expenses for the three months ended December 31, 2004 compared to the same period in 2003 was primarily due to the positive impacts of income tax and foreign exchange related items.

SHARE INFORMATION

As at March 1, 2005, TransCanada had 485,240,166 issued and outstanding common shares. In addition, there were approximately 10,694,000 outstanding options to purchase common shares, of which approximately 8,443,000 were exercisable as at March 1, 2005.

OTHER INFORMATION

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

Other selected consolidated financial information for the years ended December 31, 2004, 2003, 2002, 2001 and 2000 is found under the heading "Five-Year Financial Highlights" on pages 108 and 109 of this Annual Report.

FORWARD-LOOKING INFORMATION

Certain information in this Management's Discussion and Analysis is forward-looking and is subject to important risks and uncertainties. The results or events predicted in this information may differ from actual results or events. 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, competitive factors in the pipeline and power industry sectors and the prevailing economic conditions in North America. For additional information on these and other factors, see the reports filed by TransCanada with Canadian securities regulators and with the SEC. TransCanada disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

GLOSSARY OF TERMS

2004 Application 2004 Canadian Mainline Tolls and Tariff Application

APG Aboriginal Pipeline Group

ATCO ATCO Pipelines

B.C. British Columbia

Bcf/d Billion cubic feet per day

Boston Edison Boston Edison Company

Bruce Power Bruce Power L.P.

Cameco Cameco Corporation

CAPP Canadian Association of Petroleum Producers

Cartier Wind Cartier Wind Energy

CBM Coalbed methane

CICA Canadian Institute of Chartered Accountants

CrossAlta CrossAlta Gas Storage & Services Ltd.

DBRS Dominion Bond Rating Service Limited

Disclosure controls Disclosure controls and procedures

EUB Alberta Energy and Utilities Board

FCA Federal Court of Appeal

FERC U.S. Federal Energy Regulatory Commission

Foothills Foothills Pipe Lines Ltd.

FT Firm transportation

FT-NR Non-renewable firm transportation

FT-RAM Firm transportation service enhancement

GAAP Generally accepted accounting principles

Gas Pacifico Gasoducto del Pacifico

GCOC Generic Cost of Capital

GRA General Rate Application

Great Lakes Great Lakes Gas Transmission System

GTN Gas Transmission Northwest System and the North Baja System, collectively

GUA Gas Utilities Act (Alberta)

GWh Gigawatt hours

Hydro-Québec Hydro-Québec Distribution

INNERGY INNERGY Holdings S.A.

Iroquois Iroquois Gas Transmission System

Keystone Keystone Pipeline

Km Kilometres

LNG Liquefied natural gas

Millennium Millennium Pipeline project

MMcf/d Million cubic feet per day

Moody's Moody's Investors Service

MW Megawatts

MWh Megawatt hour

NBJ North Bay Junction

NEB National Energy Board

Net earnings Net income from continuing operations

Northern Border Northern Border Pipeline

NPA Northern Pipeline Act of Canada

OM&A Operating, maintenance and administration

OPG Ontario Power Generation

OSP Ocean State Power

Paiton P.T. Paiton Energy Company

Portland Portland Natural Gas Transmission System

Portlands Energy Portlands Energy Centre L.P.

Power LP TransCanada Power, L.P.

PPAs Power purchase arrangements

ROE Rate of return on common equity

SEC U.S. Securities and Exchange Commission

Shell Shell US Gas & Power LLC

Simmons Simmons Pipeline System

TCPL TransCanada PipeLines Limited

TCPM TransCanada Power Marketing Limited

The Consortium The consortium that includes Cameco and BPC Generation Infrastructure Trust

TQM Trans Québec & Maritimes System

TransCanada or the company TransCanada Corporation

TransGas TransGas de Occidente S.A.

Tuscarora Tuscarora Gas Transmission System

U.S. United States

USGen USGen New England

Ventures LP TransCanada Pipeline Ventures Limited Partnership

Vermont Hydroelectric Vermont Hydroelectric Power Authority

WCSB Western Canada Sedimentary Basin

2004 CONSOLIDATED FINANCIAL STATEMENTS

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 2004 to 2003 and should be read in conjunction with the consolidated financial statements and accompanying notes. In addition, significant changes between 2003 and 2002 are highlighted. Note 22 to the consolidated financial statements describes the impact on the consolidated financial statements of significant differences between Canadian and United States GAAP.

Management has developed 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.

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. 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 on page 69 outlines the scope of their examination and their opinion on the consolidated financial statements.

Harold N. Kvisle
President and
Chief Executive Officer

Russell K. Girling
Executive Vice-President, Corporate Development
and Chief Financial Officer

February 28, 2005

AUDITORS' REPORT

To the Shareholders of TransCanada Corporation

We have audited the consolidated balance sheets of TransCanada Corporation as at December 31, 2004 and 2003 and the statements of consolidated income, consolidated retained earnings and consolidated cash flows for each of the years in the three-year period ended December 31, 2004. 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. 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, 2004 and 2003 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2004 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada
February 28, 2005

CONSOLIDATED INCOME

Year ended December 31 (millions of dollars except per share amounts)	2004	2003	2002
Revenues	**5,107**	5,357	5,214
Operating Expenses			
Cost of sales	**539**	692	627
Other costs and expenses	**1,635**	1,682	1,546
Depreciation	**945**	914	848
	3,119	3,288	3,021
Operating Income	**1,988**	2,069	2,193
Other Expenses/(Income)			
Financial charges (Note 9)	**810**	821	867
Financial charges of joint ventures	**60**	77	90
Equity income (Note 7)	**(171)**	(165)	(33)
Interest income and other	**(65)**	(60)	(53)
Gains related to Power LP (Note 8)	**(197)**	–	–
	437	673	871
Income from Continuing Operations before Income Taxes and Non-Controlling Interests	**1,551**	1,396	1,322
Income Taxes (Note 15)			
Current	**431**	305	270
Future	**77**	230	247
	508	535	517
Non-Controlling Interests (Note 12)	**63**	60	58
Net Income from Continuing Operations	**980**	801	747
Net Income from Discontinued Operations (Note 21)	**52**	50	–
Net Income	**1,032**	851	747
Net Income Per Share (Note 13)			
Basic			
Continuing operations	**$ 2.02**	$ 1.66	$ 1.56
Discontinued operations	**0.11**	0.10	–
	$ 2.13	$ 1.76	$ 1.56
Diluted			
Continuing operations	**$ 2.01**	$ 1.66	$ 1.55
Discontinued operations	**0.11**	0.10	–
	$ 2.12	$ 1.76	$ 1.55

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

CONSOLIDATED CASH FLOWS

Year ended December 31 (millions of dollars)	**2004**	2003	2002
Cash Generated from Operations			
Net income from continuing operations	**980**	801	747
Depreciation	**945**	914	848
Future income taxes	**77**	230	247
Gains related to Power LP	**(197)**	–	–
Equity income in excess of distributions received (Note 7)	**(123)**	(119)	(6)
Non-controlling interests	**63**	60	58
Pension funding in excess of expense	**(29)**	(65)	(33)
Other	**(42)**	(11)	(34)
Funds generated from continuing operations	**1,674**	1,810	1,827
Decrease in operating working capital (Note 19)	**34**	112	33
Net cash provided by continuing operations	**1,708**	1,922	1,860
Net cash (used in)/provided by discontinued operations	**(6)**	(17)	59
	1,702	1,905	1,919
Investing Activities			
Capital expenditures	**(476)**	(391)	(599)
Acquisitions, net of cash acquired (Note 8)	**(1,516)**	(570)	(228)
Disposition of assets (Note 8)	**410**	–	–
Deferred amounts and other	**(24)**	(138)	(112)
Net cash used in investing activities	**(1,606)**	(1,099)	(939)
Financing Activities			
Dividends and preferred securities charges	**(623)**	(588)	(546)
Notes payable issued/(repaid), net	**179**	(62)	(46)
Long-term debt issued	**1,042**	930	–
Reduction of long-term debt	**(997)**	(744)	(486)
Non-recourse debt of joint ventures issued	**233**	60	44
Reduction of non-recourse debt of joint ventures	**(113)**	(71)	(80)
Partnership units of joint ventures issued	**88**	–	–
Common shares issued	**32**	65	50
Redemption of junior subordinated debentures	**–**	(218)	–
Net cash used in financing activities	**(159)**	(628)	(1,064)
Effect of Foreign Exchange Rate Changes on Cash and Short-Term Investments	**(87)**	(52)	(3)
(Decrease)/Increase in Cash and Short-Term Investments	**(150)**	126	(87)
Cash and Short-Term Investments			
Beginning of year	**338**	212	299
Cash and Short-Term Investments			
End of year	**188**	338	212

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

CONSOLIDATED BALANCE SHEET

December 31 (millions of dollars)	**2004**	2003
ASSETS		
Current Assets		
Cash and short-term investments	**188**	338
Accounts receivable	**627**	605
Inventories	**174**	165
Other	**120**	88
	1,109	1,196
Long-Term Investments (Note 7)	**840**	733
Plant, Property and Equipment (Notes 4, 9 and 10)	**18,704**	17,415
Other Assets (Note 5)	**1,477**	1,357
	22,130	20,701
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable (Note 16)	**546**	367
Accounts payable	**1,135**	1,087
Accrued interest	**214**	208
Current portion of long-term debt (Note 9)	**766**	550
Current portion of non-recourse debt of joint ventures (Note 10)	**83**	19
	2,744	2,231
Deferred Amounts (Note 11)	**666**	561
Long-Term Debt (Note 9)	**9,713**	9,465
Future Income Taxes (Note 15)	**509**	427
Non-Recourse Debt of Joint Ventures (Note 10)	**779**	761
Preferred Securities (Note 12)	**19**	22
	14,430	13,467
Non-Controlling Interests (Note 12)	**1,135**	1,143
Shareholders' Equity		
Common shares (Note 13)	**4,711**	4,679
Contributed surplus	**270**	267
Retained earnings	**1,655**	1,185
Foreign exchange adjustment (Note 14)	**(71)**	(40)
	6,565	6,091
Commitments, Contingencies and Guarantees (Note 20)		
	22,130	20,701

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

On behalf of the Board:

Harry G Schaefer

Harold N. Kvisle
Director

Harry G. Schaefer
Director

CONSOLIDATED RETAINED EARNINGS

Year ended December 31 (millions of dollars)	**2004**	2003	2002
Balance at beginning of year	**1,185**	854	586
Net income	**1,032**	851	747
Common share dividends	**(562)**	(520)	(479)
	1,655	1,185	854

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

GAS TRANSMISSION

The Gas Transmission 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., Saskatchewan and the United States borders (the Foothills System);
- 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 (the North Baja System); and
- natural gas transmission systems in Alberta which supply natural gas to the oil sands region of northern Alberta and to a petrochemical complex at Joffre, Alberta (Ventures LP).

Gas Transmission also holds the Company's investments in other natural gas pipelines and natural gas storage facilities located primarily in Canada and the U.S. In addition, Gas Transmission investigates and develops new natural gas transmission, natural gas storage and liquefied natural gas regasification facilities in Canada and the U.S.

POWER

The Power segment builds, owns and operates electrical power generation plants, and markets electricity. Power also holds the Company's investments in other electrical power generation plants. This business operates in Canada and the U.S.

NOTE 1 Accounting Policies

The consolidated financial statements of the Company have been prepared by Management in accordance with Canadian generally accepted accounting principles (GAAP). These accounting principles are different in some respects from U.S. GAAP and the significant differences are described in Note 22. 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 Pursuant to a plan of arrangement, effective May 15, 2003, common shares of TransCanada PipeLines Limited (TCPL) were exchanged on a one-to-one basis for common shares of TransCanada. As a result, TCPL became a wholly-owned subsidiary of TransCanada. The consolidated financial statements for the years ended December 31, 2004 and 2003 include the accounts of TransCanada, the consolidated accounts of all subsidiaries, including TCPL, and TransCanada's proportionate share of the accounts of the Company's joint venture investments. Comparative information for the year ended December 31, 2002 is that of TCPL, its subsidiaries and its proportionate share of the accounts of its joint venture investments at that time.

On November 1, 2004, the Company acquired a 100 per cent interest in the Gas Transmission Northwest System and the North Baja System (collectively GTN) and, as a result, GTN was consolidated subsequent to that date. In December 2003, TransCanada increased its ownership interest in Portland Natural Gas Transmission System Partnership (Portland) to 61.7 per cent from 43.4 per cent. Subsequent to the acquisition, Portland was consolidated in the Company's financial statements with 38.3 per cent reflected in non-controlling interests. In August 2003, the Company acquired the remaining interests in Foothills Pipe Lines Ltd. and its subsidiaries (Foothills) previously not held by TransCanada, and Foothills was consolidated subsequent to that date.

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, the Foothills System, and Trans Québec & Maritimes Pipeline Inc. (Trans Québec & Maritimes) 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). These Canadian natural gas transmission operations are regulated with respect to the determination of revenues, tolls, construction and operations. The NEB approved interim tolls for 2004 for the Canadian Mainline. The tolls will remain interim pending a decision on Phase II of the 2004 Tolls and Tariff Application, which will address capital structure, for the Canadian Mainline. Any adjustments to the interim tolls will be recorded in accordance with the NEB decision. The Gas Transmission Northwest System, the North Baja System and the other natural gas pipelines in the U.S. are subject to the authority of the Federal Energy Regulatory Commission (FERC). 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.

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 are carried at the lower of average cost or net realizable value and primarily consist of materials and supplies including spare parts and storage gas.

Plant, Property and Equipment

Gas Transmission Plant, property and equipment of natural gas transmission 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 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.

Power Plant, property and equipment in the Power business are recorded at cost and depreciated on a straight-line basis over estimated service lives at average annual rates generally ranging from two to four per cent. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives. Interest is capitalized on capital projects.

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.

Power Purchase Arrangements Power purchase arrangements (PPAs) are long-term contracts to purchase or sell power on a predetermined basis. The initial payments for PPAs acquired by TransCanada are deferred and amortized over the terms of the contracts, from the dates of acquisition, which range from eight to 23 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 prior to 2003 is ten years and for options granted in 2003 and subsequently, the contractual life is seven years. Options may be exercised at a price determined at the time the option is awarded. Generally, for awards granted prior to 2003, 25 per cent of the options vest on the award date and 25 per cent on each of the three following award date anniversaries. For awards granted subsequent to 2002, no options vest on the award date and 33.3 per cent vest on each of the three following award date anniversaries. Effective January 1, 2002, TransCanada adopted the fair value method of accounting for stock options. The Company is recording compensation expense over the three year vesting period. This charge is reflected in the Gas Transmission and Power 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 as the Company does not intend to repatriate these earnings in the foreseeable future.

Foreign Currency Translation Most of 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.

Certain foreign operations included in TransCanada's investment in TransCanada Power, L.P. (Power LP) are integrated and are translated into Canadian dollars using the temporal method. Under this method, monetary assets and liabilities are translated at period end exchange rates, non-monetary assets and liabilities are translated at historical exchange rates, revenues and expenses are translated at the exchange rate in effect at the time of the transaction and depreciation of assets translated at historical rates is translated at the same rate as the asset to which it relates. Gains and losses on translation are reflected in income when incurred.

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 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. Gains or losses relating to derivatives that are hedges are deferred and recognized in the same period and in the same financial statement category as the corresponding hedged transactions. The recognition of gains and losses on derivatives used as hedges for Canadian Mainline, Alberta System, GTN and the Foothills System exposures is determined through the regulatory process.

A derivative must be designated and effective to be accounted for as a hedge. For cash flow hedges, effectiveness is achieved if the changes in the cash flows of the derivative substantially offset the changes in the cash flows of the hedged position and the timing of the cash flows is similar. Effectiveness for fair value hedges is achieved if changes in the fair value of the derivative substantially offset changes in the fair value attributable to the hedged item. In the event that a derivative does not meet the designation or effectiveness criterion, the derivative is accounted for at fair value and realized and unrealized gains and losses on the derivative are recognized in income. If a derivative that qualifies as a hedge is settled early, the gain or loss at settlement is deferred and recognized when the corresponding hedged transaction is recognized. Premiums paid or received with respect to derivatives that are hedges are deferred and amortized to income over the term of the hedge.

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. 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 the net actuarial gain or loss 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 previously sponsored two additional plans, a defined contribution plan and a combination of the defined benefit and defined contribution plans, which were effectively terminated at December 31, 2002.

The Company has broad-based, medium-term employee incentive plans, which grant units to each eligible employee. 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. The units under one of these incentive plans vested at the end of 2004 and the Company recorded compensation expense over the three year vesting period. The value of units under this plan, net of income tax, will be paid in cash in 2005.

NOTE 2 Accounting Changes

Asset Retirement Obligations Effective January 1, 2004, the Company adopted the new standard of the Canadian Institute of Chartered Accountants (CICA) Handbook Section "Asset Retirement Obligations", which addresses financial accounting and reporting for obligations associated with asset retirement costs. This section requires that the fair value of a liability for an asset retirement obligation be recognized 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. The liability is accreted at the end of each period through charges to operating expenses. This accounting change was applied retroactively with restatement of prior periods.

The plant, property and equipment of the regulated natural gas transmission operations consists primarily of underground pipelines and above ground compression equipment and other facilities. No amount has been recorded for asset retirement obligations relating to these assets as it is not possible to make a reasonable estimate of the fair value of the liability due to the indeterminate timing and scope 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 Gas Transmission, excluding regulated natural gas transmission operations, the impact of this accounting change resulted in an increase of $2 million in plant, property and equipment and in the estimated fair value of the liability as at January 1, 2003 and December 31, 2003.

The plant, property and equipment in the Power business consists primarily of power plants in Canada and the U.S. The impact of this accounting change resulted in an increase of $6 million and $7 million in plant, property and equipment and in the estimated fair value of the liability as at January 1, 2003 and December 31, 2003, respectively. The asset retirement cost, net of accumulated depreciation that would have been recorded if the cost had been recorded in the period in which it arose, is recorded as an additional cost of the assets as at January 1, 2003.

The impact of this change on TransCanada's net income in prior years was nil. The impact of this accounting change on the Company's financial statements as at and for the year ended December 31, 2004 is disclosed in Note 17.

Hedging Relationships Effective January 1, 2004, the Company adopted the provisions of the CICA's new Accounting Guideline "Hedging Relationships" that specifies the circumstances in which hedge accounting is appropriate, including the identification, documentation, designation and effectiveness of hedges, and the discontinuance of hedge accounting. The adoption of the new guideline, which TransCanada applied prospectively, had no significant impact on net income for the year ended December 31, 2004.

Generally Accepted Accounting Principles Effective January 1, 2004, the Company adopted the new standard of the CICA Handbook Section "Generally Accepted Accounting Principles" that defines primary sources of GAAP and the other sources that need to be considered in the application of GAAP. The new standard eliminates the ability to rely on industry practice to support a particular accounting policy and provides an exemption for rate-regulated operations.

This accounting change was applied prospectively and there was no impact on net income in the year ended December 31, 2004. In prior years, in accordance with industry practice, certain assets and liabilities related to the Company's regulated activities, and offsetting deferral accounts, were not recognized on the balance sheet. The impact of the change on the consolidated balance sheet as at January 1, 2004 is as follows.

(millions of dollars)	Increase/(Decrease)
Other assets	153
Deferred amounts	80
Long-term debt	76
Preferred securities	(3)
Total liabilities	153

NOTE 3 Segmented Information

Net Income/(Loss) (1)

Year ended December 31, 2004 (millions of dollars)	Gas Transmission	Power	Corporate	Total
Revenues	**3,917**	**1,190**	**–**	**5,107**
Cost of sales (2)	**–**	**(539)**	**–**	**(539)**
Other costs and expenses	**(1,225)**	**(407)**	**(3)**	**(1,635)**
Depreciation	**(873)**	**(72)**	**–**	**(945)**
Operating income/(loss)	**1,819**	**172**	**(3)**	**1,988**
Financial charges and non-controlling interests	**(785)**	**(9)**	**(79)**	**(873)**
Financial charges of joint ventures	**(56)**	**(4)**	**–**	**(60)**
Equity income	**41**	**130**	**–**	**171**
Interest income and other	**14**	**14**	**37**	**65**
Gains related to Power LP	**–**	**197**	**–**	**197**
Income taxes	**(447)**	**(104)**	**43**	**(508)**
Continuing operations	**586**	**396**	**(2)**	**980**
Discontinued operations				**52**
Net Income				**1,032**

Year ended December 31, 2003 (millions of dollars)	Gas Transmission	Power	Corporate	Total
Revenues	3,956	1,401	–	5,357
Cost of sales (2)	–	(692)	–	(692)
Other costs and expenses	(1,270)	(405)	(7)	(1,682)
Depreciation	(831)	(82)	(1)	(914)
Operating income/(loss)	1,855	222	(8)	2,069
Financial charges and non-controlling interests	(781)	(11)	(89)	(881)
Financial charges of joint ventures	(76)	(1)	–	(77)
Equity income	66	99	–	165
Interest income and other	17	14	29	60
Income taxes	(459)	(103)	27	(535)
Continuing operations	622	220	(41)	801
Discontinued operations				50
Net Income				851

Year ended December 31, 2002 (millions of dollars)	Gas Transmission	Power	Corporate	Total
Revenues	3,921	1,293	–	5,214
Cost of sales (2)	–	(627)	–	(627)
Other costs and expenses	(1,166)	(371)	(9)	(1,546)
Depreciation	(783)	(65)	–	(848)
Operating income/(loss)	1,972	230	(9)	2,193
Financial charges and non-controlling interests	(821)	(13)	(91)	(925)
Financial charges of joint ventures	(90)	–	–	(90)
Equity income	33	–	–	33
Interest income and other	17	13	23	53
Income taxes	(458)	(84)	25	(517)
Continuing operations	653	146	(52)	747
Discontinued operations				–
Net Income				747

(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.

(2) Cost of sales is comprised of commodity purchases for resale.

Total Assets

December 31 (millions of dollars)	**2004**	2003
Gas Transmission	**18,428**	17,064
Power	**2,802**	2,753
Corporate	**893**	873
Continuing operations	**22,123**	20,690
Discontinued operations	**7**	11
	22,130	20,701

Geographic Information

Year ended December 31 (millions of dollars)	**2004**	2003	2002 (4)
Revenues (3)			
Canada – domestic	**3,147**	3,257	2,731
Canada – export	**1,261**	1,293	1,641
United States	**699**	807	842
	5,107	5,357	5,214

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

(4) Canada – domestic revenues were reduced in 2002 as a result of transportation service credits of $662 million. These services were discontinued in 2003.

Plant, Property and Equipment

December 31 (millions of dollars)	**2004**	2003
Canada	**14,757**	15,156
United States	**3,947**	2,259
	18,704	17,415

Capital Expenditures

Year ended December 31 (millions of dollars)	**2004**	2003	2002
Gas Transmission	**187**	256	382
Power	**285**	132	193
Corporate and Other	**4**	3	24
	476	391	599

NOTE 4 Plant, Property and Equipment

December 31 (millions of dollars)	2004			2003		
	Cost	**Accumulated Depreciation**	**Net Book Value**	Cost	Accumulated Depreciation	Net Book Value
Gas Transmission						
Canadian Mainline						
Pipeline	**8,695**	**3,421**	**5,274**	8,683	3,176	5,507
Compression	**3,322**	**947**	**2,375**	3,318	832	2,486
Metering and other	**366**	**125**	**241**	404	132	272
	12,383	**4,493**	**7,890**	12,405	4,140	8,265
Under construction	**16**	**–**	**16**	12	–	12
	12,399	**4,493**	**7,906**	12,417	4,140	8,277
Alberta System						
Pipeline	**4,978**	**2,055**	**2,923**	4,934	1,908	3,026
Compression	**1,496**	**599**	**897**	1,507	549	958
Metering and other	**861**	**262**	**599**	862	211	651
	7,335	**2,916**	**4,419**	7,303	2,668	4,635
Under construction	**20**	**–**	**20**	13	–	13
	7,355	**2,916**	**4,439**	7,316	2,668	4,648
GTN (1)						
Pipeline	**1,131**	**9**	**1,122**			
Compression	**726**	**2**	**724**			
Metering and other	**187**	**1**	**186**			
	2,044	**12**	**2,032**			
Under construction	**17**	**–**	**17**			
	2,061	**12**	**2,049**			
Foothills System						
Pipeline	**815**	**346**	**469**	834	317	517
Compression	**373**	**114**	**259**	378	99	279
Metering and other	**78**	**35**	**43**	60	35	25
	1,266	**495**	**771**	1,272	451	821
Joint Ventures and other	**3,213**	**1,053**	**2,160**	3,361	1,052	2,309
	26,294	**8,969**	**17,325**	24,366	8,311	16,055
Power (2)						
Power generation facilities	**1,397**	**375**	**1,022**	1,439	381	1,058
Other	**77**	**45**	**32**	84	41	43
	1,474	**420**	**1,054**	1,523	422	1,101
Under construction	**288**	**–**	**288**	209	–	209
	1,762	**420**	**1,342**	1,732	422	1,310
Corporate	**124**	**87**	**37**	122	72	50
	28,180	**9,476**	**18,704**	26,220	8,805	17,415

(1) TransCanada acquired GTN on November 1, 2004.

(2) Certain Power generation facilities are accounted for as assets under operating leases. At December 31, 2004, the net book value of these facilities was $70 million. Revenues of $7 million were attributed to the PPAs of these facilities in 2004.

NOTE 5 Other Assets

December 31 (millions of dollars)	**2004**	2003
Derivative contracts	**253**	118
PPAs – Canada (1)	**274**	278
PPAs – U.S. (1)	**98**	248
Pension and other benefit plans	**209**	201
Regulatory deferrals	**199**	212
Loans and advances (2)	**135**	111
Goodwill	**58**	–
Other	**251**	189
	1,477	1,357

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

December 31 (millions of dollars)	**2004**			2003		
	Cost	**Accumulated Amortization**	**Net Book Value**	Cost	Accumulated Amortization	Net Book Value
PPAs – Canada	**345**	**71**	**274**	329	51	278
PPAs – U.S.	**102**	**4**	**98**	276	28	248

The aggregate amortization expense with respect to the PPAs was $24 million for the year ended December 31, 2004 (2003 – $37 million; 2002 – $28 million). The amortization expense with respect to the Company's PPAs approximate: 2005 – $26 million; 2006 – $26 million; 2007 – $26 million; 2008 – $26 million; and 2009 – $26 million. In April 2004, the Company disposed of all its PPAs – U.S. to Power LP and, as a result of its joint venture investment in Power LP, recorded US$74 million of PPAs – U.S. In 2004, TransCanada also recorded $16 million of PPAs – Canada.

(2) Includes a $75 million unsecured note receivable from Bruce Power L.P. (Bruce Power) bearing interest at 10.5 per cent per annum, due February 14, 2008.

NOTE 6 Joint Venture Investments

		TransCanada's Proportionate Share				
		Income Before Income Taxes Year ended December 31			Net Assets December 31	
(millions of dollars)	**Ownership Interest**	**2004**	2003	2002	**2004**	2003
Gas Transmission						
Great Lakes	50.0% (1)	**86**	81	102	**379**	419
Iroquois	41.0% (1)	**28**	31	30	**175**	169
TC PipeLines, LP	33.4%	**22**	21	24	**124**	130
Trans Québec & Maritimes	50.0%	**13**	14	13	**75**	77
CrossAlta	60.0% (1)	**20**	11	21	**24**	25
Foothills	(2)	**–**	19	29	**–**	–
Other	Various	**6**	7	7	**27**	22
Power						
Power LP	30.6% (3)	**32**	25	26	**289**	234
ASTC Power Partnership	50.0% (4)	**–**	–	–	**93**	99
		207	209	252	**1,186**	1,175

(1) Great Lakes Gas Transmission Limited Partnership (Great Lakes); Iroquois Gas Transmission System, L.P. (Iroquois); CrossAlta Gas Storage & Services Ltd. (CrossAlta).

(2) In August 2003, the Company acquired the remaining interests in Foothills previously not held by TransCanada, and Foothills was consolidated subsequent to that date.

(3) In April 2004, the Company's interest in Power LP decreased to 30.6 per cent from 35.6 per cent.

(4) The Company has a 50.0 per cent ownership interest in ASTC Power Partnership, which is located in Alberta and holds a PPA. The underlying power volumes related to the 50.0 per cent ownership interest in the Partnership are effectively transferred to TransCanada.

Consolidated retained earnings at December 31, 2004 include undistributed earnings from these joint ventures of $509 million (2003 – $509 million).

Summarized Financial Information of Joint Ventures

Year ended December 31 (millions of dollars)	**2004**	2003	2002
Income			
Revenues	**559**	623	680
Other costs and expenses	**(238)**	(275)	(251)
Depreciation	**(88)**	(96)	(119)
Financial charges and other	**(26)**	(43)	(58)
Proportionate share of income before income taxes of joint ventures	**207**	209	252

Year ended December 31 (millions of dollars)	**2004**	2003	2002
Cash Flows			
Operations	**269**	272	323
Investing activities	**(179)**	(114)	(124)
Financing activities	**(76)**	(156)	(210)
Effect of foreign exchange rate changes on cash and short-term investments	**(5)**	(10)	(1)
Proportionate share of increase/(decrease) in cash and short-term investments of joint ventures	**9**	(8)	(12)

December 31 (millions of dollars)	**2004**	2003
Balance Sheet		
Cash and short-term investments	**64**	55
Other current assets	**133**	106
Long-term investments	**105**	118
Plant, property and equipment	**1,644**	1,693
Other assets and deferred amounts (net)	**221**	109
Current liabilities	**(153)**	(94)
Non-recourse debt	**(779)**	(761)
Future income taxes	**(49)**	(51)
Proportionate share of net assets of joint ventures	**1,186**	1,175

NOTE 7 Long-Term Investments

		TransCanada's Share							
		Distributions From Equity Investments Year ended December 31			Income From Equity Investments Year ended December 31			Equity Investments December 31	
(millions of dollars)	**Ownership Interest**	**2004**	2003	2002	**2004**	2003	2002	**2004**	2003
Power									
Bruce Power	31.6%	**–**	–	–	**130**	99	–	**642**	513
Gas Transmission									
Northern Border	10.0% (1)	**27**	22	26	**23**	22	25	**91**	103
TransGas de Occidente S.A.	46.5%	**8**	8	–	**11**	27	5	**78**	80
Portland	61.7% (2)	**–**	10	–	**–**	14	2	**–**	–
Other	Various	**13**	6	1	**7**	3	1	**29**	37
		48	46	27	**171**	165	33	**840**	733

(1) The Northern Border equity investment effective ownership interest of 10.0 per cent is the result of the Company holding a 33.4 per cent interest in TC PipeLines, LP, which holds a 30.0 per cent interest in Northern Border Pipeline Company (Northern Border).

(2) In September 2003, the Company increased its ownership interest in Portland to 43.4 per cent from 33.3 per cent. In December 2003, the Company increased its ownership interest to 61.7 per cent and the investment was fully consolidated subsequent to that date.

Consolidated retained earnings at December 31, 2004 include undistributed earnings from these equity investments of $285 million (2003 – $166 million).

NOTE 8 Acquisitions and Dispositions

Acquisitions

GTN On November 1, 2004, TransCanada acquired GTN for approximately US$1,730 million, including US$528 million of assumed debt and closing adjustments. The purchase price was allocated on a preliminary basis as follows using an estimate of fair values of the net assets at the date of acquisition.

Purchase Price Allocation
(millions of U.S. dollars)

Current assets	45
Plant, property and equipment	1,712
Other non-current assets	30
Goodwill	48
Current liabilities	(54)
Long-term debt	(528)
Other non-current liabilities	(51)
	1,202

Goodwill, which is attributable to the North Baja System, will be re-evaluated on an annual basis for impairment. Factors that contributed to goodwill include opportunities for expansion, a strong competitive position, strong demand for gas in the western markets and access to an ample supply of relatively low-cost gas. The goodwill recognized on this transaction is expected to be fully deductible for tax purposes.

The acquisition was accounted for using the purchase method of accounting. The financial results of GTN have been consolidated with those of TransCanada subsequent to the acquisition date and included in the Gas Transmission segment.

Bruce Power On February 14, 2003, the Company acquired a 31.6 per cent interest in Bruce Power for $409 million, including closing adjustments. As part of the acquisition, the Company also funded a one-third share ($75 million) of a $225 million accelerated deferred rent payment made by Bruce Power to Ontario Power Generation. The resulting note receivable from Bruce Power is recorded in other assets.

The purchase price of the Company's 31.6 per cent interest in Bruce Power was allocated as follows.

Purchase Price Allocation
(millions of dollars)

Net book value of assets acquired	281
Capital lease	301
Power sales agreements	(131)
Pension liability and other	(42)
	409

The amount allocated to the investment in Bruce Power includes a purchase price allocation of $301 million to the capital lease of the Bruce Power plant which is being amortized on a straight-line basis over the lease term which extends to 2018, resulting in an annual amortization expense of $19 million. The amount allocated to the power sales agreements is being amortized to income over the remaining term of the underlying sales contracts. The amortization of the fair value allocated to these contracts is: 2003 – $38 million; 2004 – $37 million; 2005 – $25 million; 2006 – $29 million; and 2007 – $2 million.

Dispositions

Power LP On April 30, 2004, TransCanada sold the ManChief and Curtis Palmer power facilities to Power LP for US$402.6 million, plus closing adjustments of US$12.8 million, and recognized a gain of $25 million pre tax ($15 million after tax). Power LP funded the purchase through an issue of 8.1 million subscription receipts and third party debt. As part of the subscription receipts offering, TransCanada purchased 540,000 subscription receipts for an aggregate purchase price of $20 million. The subscription receipts were subsequently converted into partnership units. The net impact of this issue reduced TransCanada's ownership interest in Power LP to 30.6 per cent from 35.6 per cent.

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 eliminates 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. This amount includes the recognition of unamortized gains of $132 million on previous Power LP transactions.

NOTE 9 Long-Term Debt

		2004		2003	
	Maturity Dates	**Outstanding December 31** (1)	**Weighted Average Interest Rate** (2)	Outstanding December 31 (1)	Weighted Average Interest Rate (2)
Canadian Mainline (3)					
First Mortgage Pipe Line Bonds					
Pounds Sterling (2004 and 2003 – £25)	2007	**58**	**16.5%**	58	16.5%
Debentures					
Canadian dollars	2008 to 2020	**1,354**	**10.9%**	1,354	10.9%
U.S. dollars (2004 – US$600; 2003 – US$800)	2012 to 2021	**722**	**9.5%**	1,034	9.2%
Medium-Term Notes					
Canadian dollars	2005 to 2031	**2,167**	**6.9%**	2,312	6.9%
U.S. dollars (2004 and 2003 – US$120)	2010	**144**	**6.1%**	155	6.1%
Foreign exchange differential recoverable through the tollmaking process (8)		**–**		(60)	
		4,445		4,853	
Alberta System (4)					
Debentures and Notes					
Canadian dollars	2007 to 2024	**607**	**11.6%**	627	11.6%
U.S. dollars (2004 – US$375; 2003 – US$500)	2012 to 2023	**451**	**8.2%**	646	8.3%
Medium-Term Notes					
Canadian dollars	2005 to 2030	**767**	**7.4%**	767	7.4%
U.S. dollars (2004 and 2003 – US$233)	2026 to 2029	**280**	**7.7%**	301	7.7%
Foreign exchange differential recoverable through the tollmaking process (8)		**–**		(16)	
		2,105		2,325	
GTN (5)					
Unsecured Debentures and Notes (2004 – US$525)	2005 to 2025	**632**	**7.2%**		
Foothills System (3)					
Senior Secured Notes		**–**		80	4.3%
Senior Unsecured Notes	2009 to 2014	**400**	**4.9%**	300	4.7%
		400		380	
Portland (6)					
Senior Secured Notes					
U.S. dollars (2004 – US$256; 2003 – US$271)	2018	**308**	**5.9%**	350	5.9%
Other					
Medium-Term Notes (3)					
Canadian dollars	2005 to 2030	**592**	**6.2%**	592	6.2%
U.S. dollars (2004 – US$521; 2003 – US$665)	2006 to 2025	**627**	**6.9%**	859	6.8%
Subordinated Debentures (3)					
U.S. dollars (2004 and 2003 – US$57)	2006	**68**	**9.1%**	74	9.1%
Unsecured Loans, Debentures and Notes (7)					
U.S. dollars (2004 – US$1,082; 2003 – US$446)	2005 to 2034	**1,302**	**5.1%**	582	4.9%
		2,589		2,107	
		10,479		10,015	
Less: Current Portion of Long-Term Debt		**766**		550	
		9,713		9,465	

(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: Foothills senior unsecured notes in 2003 – 5.8 per cent; Portland senior secured notes in 2003 – 6.2 per cent; Other U.S. dollar subordinated debentures – 9.0 per cent (2003 – 9.0 per cent); and Other U.S. dollar unsecured loans, debentures and notes – 5.2 per cent (2003 – 5.2 per cent).
(3) Long-term debt of TCPL.
(4) Long-term debt of NOVA Gas Transmission Ltd. excluding a $241 million note held by TCPL (2003 – $258 million).
(5) Long-term debt of Gas Transmission Northwest Corporation.
(6) Long-term debt of Portland.
(7) Long-term debt of TCPL, excluding $85 million held by OSP Finance Company and $14 million held by TC Ocean State Corporation.
(8) See Note 2, Accounting Changes – "Generally Accepted Accounting Principles".

Principal Repayments Principal repayments on the long-term debt of the Company approximate: 2005 – $766 million; 2006 – $387 million; 2007 – $615 million; 2008 – $545 million; and 2009 – $753 million.

Debt Shelf Programs At December 31, 2004, $1.5 billion of medium-term note debentures could be issued under a base shelf program in Canada and US$1 billion of debt securities could be issued under a debt shelf program in the U.S. In January 2005, the Company issued $300 million of 12-year medium-term notes bearing interest of 5.1 per cent under the Canadian base shelf program.

CANADIAN MAINLINE

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.

ALBERTA SYSTEM

Debentures Debentures amounting to $225 million have retraction provisions which entitle the holders to require redemption of up to 8 per cent of the then outstanding principal plus accrued and unpaid interest on specified repayment dates. No redemptions have been made to December 31, 2004.

Medium-Term Notes Medium-term notes 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 and the medium-term notes would become redeemable at the option of the Company.

GAS TRANSMISSION NORTHWEST CORPORATION

Senior Unsecured Notes Senior unsecured notes amounting to US$250 million are redeemable by the Company at any time on or after June 1, 2005.

OTHER

Medium-Term Notes Medium-term notes amounting to $150 million have retraction provisions which entitle the holders to require redemption of the principal plus accrued and unpaid interest in 2005.

Financial Charges

Year ended December 31 (millions of dollars)	**2004**	2003	2002
Interest on long-term debt	**805**	801	850
Regulatory deferrals and amortizations	**(31)**	(14)	(17)
Short-term interest and other financial charges	**36**	34	34
	810	821	867

The Company made interest payments of $816 million for the year ended December 31, 2004 (2003 – $846 million; 2002 – $866 million). The Company capitalized $11 million of interest for the year ended December 31, 2004 (2003 – $9 million; 2002 – nil).

NOTE 10 Non-Recourse Debt of Joint Ventures

		2004		2003	
	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					
(2004 – US$235; 2003 – US$240)	2011 to 2030	**283**	**7.9%**	310	7.9%
Iroquois					
Senior Unsecured Notes					
(2004 and 2003 – US$151)	2010 to 2027	**182**	**7.5%**	196	7.5%
Bank Loan					
(2004 – US$36; 2003 – US$43)	2008	**43**	**2.5%**	56	2.3%
Trans Québec & Maritimes					
Bonds	2005 to 2010	**143**	**7.3%**	143	7.3%
Term Loan	2006	**29**	**3.2%**	34	3.5%
TransCanada Power, L.P.					
Senior Unsecured Notes (2004 – US$58)	2014	**70**	**5.9%**	–	
Credit Facility	2009	**64**	**3.2%**	–	
Term Loan	2010	**2**	**11.3%**	–	
Other	2005 to 2012	**46**	**4.9%**	41	5.4%
		862		780	
Less: Current Portion of Non-Recourse Debt of Joint Ventures		**83**		19	
		779		761	

(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, 2004, the effective weighted average interest rates resulting from swap agreements are as follows: Iroquois bank loan – 4.1 per cent (2003 – 4.5 per cent) and Power LP Credit Facility – 5.2 per cent.

The debt of joint ventures is non-recourse to TransCanada. The security provided 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: 2005 – $83 million; 2006 – $49 million; 2007 – $18 million; 2008 – $18 million; and 2009 – $141 million.

The Company's proportionate share of the interest payments of joint ventures was $55 million for the year ended December 31, 2004 (2003 – $67 million; 2002 – $88 million).

NOTE 11 Deferred Amounts

December 31 (millions of dollars)	**2004**	2003
Derivative contracts	**209**	40
Regulatory deferrals	**229**	131
Other benefit plans	**63**	32
Deferred revenue	**58**	215
Asset retirement obligation	**36**	9
Other	**71**	134
	666	561

NOTE 12 Non-Controlling Interests and Preferred Securities

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

December 31 (millions of dollars)	**2004**	2003
Preferred securities of subsidiary	**670**	672
Preferred shares of subsidiary	**389**	389
Other	**76**	82
	1,135	1,143

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

Year ended December 31 (millions of dollars)	**2004**	2003	2002
Preferred securities charges	**31**	36	36
Preferred share dividends	**22**	22	22
Other	**10**	2	–
	63	60	58

Preferred Securities of Subsidiary

The US$460 million 8.25 per cent preferred securities of TCPL (Preferred Securities) 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.

Since the deferred interest may be settled through the issuance of common shares at the option of the issuer, the Preferred Securities are classified into their respective debt and non-controlling interest components. At December 31, 2004, the debt component of the Preferred Securities is $19 million (US$16 million) (2003 – $22 million (US$14 million)) and the non-controlling interest component of the Preferred Securities is $670 million (US$444 million) (2003 – $672 million (US$446 million)).

Effective January 1, 2005, under new Canadian accounting standards, the non-controlling interest component of Preferred Securities will be classified as debt.

Preferred Shares of Subsidiary

December 31	Number of Shares	Dividend Rate Per Share	Redemption Price Per Share	**2004**	2003
	(thousands)			(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.

Other Other non-controlling interests are primarily comprised of the 38.3 per cent non-controlling interest in Portland. Revenues received from Portland with respect to services provided by TransCanada for the year ended December 31, 2004 were $4 million (2003 and 2002 – nil).

NOTE 13 Common Shares

	Number of Shares	Amount
	(thousands)	(millions of dollars)
Outstanding at January 1, 2002	476,631	4,564
Exercise of options	2,871	50
Outstanding at December 31, 2002	479,502	4,614
Exercise of options	3,698	65
Outstanding at December 31, 2003	483,200	4,679
Exercise of options	**1,714**	**32**
Outstanding at December 31, 2004	**484,914**	**4,711**

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 484.1 million and 486.7 million (2003 – 481.5 million and 483.9 million; 2002 – 478.3 million and 480.7 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, 2002	14,450	$18.42	11,376
Granted	1,946	$21.43	
Exercised	(2,871)	$17.18	
Cancelled or expired	(633)	$23.16	
Outstanding at December 31, 2002	12,892	$18.92	10,258
Granted	1,503	$22.42	
Exercised	(3,698)	$17.59	
Cancelled or expired	(342)	$24.07	
Outstanding at December 31, 2003	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**

The following table summarizes information for stock options outstanding at December 31, 2004.

	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 $17.08	1,068	5.0	$11.68	1,068	$11.68
$18.01 to $19.00	1,508	6.0	$18.15	1,508	$18.15
$19.16 to $20.58	1,477	4.0	$20.11	1,477	$20.11
$20.59 to $21.86	1,980	7.0	$21.41	1,550	$21.41
$22.33 to $22.85	1,493	5.1	$22.35	548	$22.39
$24.49 to $25.53	1,108	3.2	$24.59	1,080	$24.56
$26.85	1,331	6.2	$26.85	8	$26.85
	9,965	5.2	$20.90	7,239	$19.58

At December 31, 2004, an additional five million common shares have been reserved for future issuance under TransCanada's Stock Option Plan. In 2004, TransCanada issued 1,330,860 options to purchase common shares at an average price of $26.85 under the Company's Stock Option Plan and the weighted average fair value of each option was determined to be $2.85. The Company used the Black-Scholes model for these calculations with the weighted average assumptions being four years of expected life, 3.3 per cent interest rate, 18 per cent volatility and 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, 2004, was $3 million (2003 and 2002 – $2 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 which entitles certain holders to purchase common shares of the Company at 50 per cent of the then market price.

NOTE 14 Risk Management and Financial Instruments

The Company issues short-term and long-term debt, including amounts in foreign currencies, purchases and sells energy commodities 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 risk that results from these activities.

Carrying Values of Derivatives The carrying amounts of derivatives, which hedge the price risk of foreign currency denominated assets and liabilities of self-sustaining foreign operations, are recorded on the balance sheet at their fair value. Gains and losses on these derivatives, realized and unrealized, are included in the foreign exchange adjustment account in Shareholders' Equity as an offset to the corresponding gains and losses on the translation of the assets and liabilities of the foreign subsidiaries. As of January 1, 2004, carrying amounts for interest rate swaps are recorded on the balance sheet at their fair value. Foreign currency transactions hedged by foreign exchange contracts are recorded at the contract rate. Power, natural gas and heat rate derivatives are recorded on the balance sheet at their fair value. The carrying amounts shown in the tables that follow are recorded in the consolidated balance sheet.

Fair Values of Financial Instruments Cash and short-term investments and notes payable are valued at their carrying amounts due to the short period to maturity. The fair values of long-term debt, non-recourse long-term debt of joint ventures and junior subordinated debentures are determined using market prices for the same or similar issues.

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

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, 2004, for foreign currency and interest rate derivatives, total credit risk and the largest credit exposure to a single counterparty were $127 million and $40 million, respectively. At December 31, 2004, for power, natural gas and heat rate derivatives, total credit risk and the largest credit exposure to a single counterparty were $19 million and $7 million, respectively.

Notional or Notional Principal Amounts Notional principal amounts are not recorded in the financial statements because these amounts are not exchanged by the Company and its counterparties and are not a measure of the Company's exposure. Notional amounts are used only as the basis for calculating payments for certain derivatives.

Foreign Investments At December 31, 2004 and 2003, the Company had foreign currency denominated assets and liabilities which created an exposure to changes in exchange rates. The Company uses foreign currency derivatives to hedge this net exposure on an after-tax basis. The foreign currency derivatives have a floating interest rate exposure which the Company partially hedges by entering into interest rate swaps and forward rate agreements. The fair values shown in the table below for those derivatives that have been designated as and are effective as hedges for foreign exchange risk are offset by translation gains or losses on the net assets and are recorded in the foreign exchange adjustment account in Shareholders' Equity.

Net Investment in Foreign Assets

Asset/(Liability)		**2004**		2003	
December 31 (millions of dollars)	Accounting Treatment	**Fair Value**	**Notional or Notional Principal Amount (U.S.)**	Fair Value	Notional or Notional Principal Amount (U.S.)
U.S. dollar cross-currency swaps (maturing 2006 to 2009)	Hedge	**95**	**400**	65	250
U.S. dollar forward foreign exchange contracts (maturing 2005)	Hedge	**(1)**	**305**	3	125
U.S. dollar options (maturing 2005)	Non-hedge	**1**	**100**	–	–

In accordance with the Company's accounting policy, each of the above derivatives is recorded on the consolidated balance sheet at its fair value in 2004. For derivatives that have been designated as and are effective as hedges of the net investment in foreign operations, the offsetting amounts are included in the foreign exchange adjustment account.

In addition, at December 31, 2004, the Company had interest rate swaps associated with the cross-currency swaps with notional principal amounts of $375 million (2003 – $311 million) and US$250 million (2003 – US$200 million). The carrying amount and fair value of these interest rate swaps was $4 million (2003 – $3 million) and $4 million (2003 – $1 million), respectively.

Reconciliation of Foreign Exchange Adjustment Gains/(Losses)

December 31 (millions of dollars)	**2004**	2003
Balance at beginning of year	**(40)**	14
Translation losses on foreign currency denominated net assets	**(64)**	(136)
Foreign exchange gains on derivatives, net of income taxes	**33**	82
	(71)	(40)

Foreign Exchange Gains/(Losses) Foreign exchange gains/(losses) included in Other Expenses/(Income) for the year ended December 31, 2004 are $4 million (2003 – nil; 2002 – $(11) million).

Foreign Exchange and Interest Rate Management Activity The Company manages certain of the foreign exchange risk of U.S. dollar debt, U.S. dollar expenses and the interest rate exposures of the Canadian Mainline, the Alberta System, GTN and the Foothills 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)		**2004**		2003	
December 31 (millions of dollars)	Accounting Treatment	**Fair Value**	**Notional or Notional Principal Amount**	Fair Value	Notional or Notional Principal Amount
Foreign Exchange					
Cross-currency swaps					
(maturing 2010 to 2012)	Hedge	**(39)**	**U.S. 157**	(26)	U.S. 282
Interest Rate					
Interest rate swaps					
Canadian dollars					
(maturing 2005 to 2008)	Hedge	**7**	**145**	(1)	340
(maturing 2006 to 2009)	Non-hedge	**9**	**374**	10	624
		16		9	
U.S. dollars					
(maturing 2010 to 2015)	Hedge	**(2)**	**U.S. 275**	11	U.S. 50
(maturing 2007 to 2009)	Non-hedge	**7**	**U.S. 100**	(3)	U.S. 50
		5		8	

In accordance with the Company's accounting policy, each of the above derivatives is recorded on the consolidated balance sheet at its fair value in 2004. At December 31, 2004, the Company also had interest rate swaps associated with the cross-currency swaps with notional principal amounts of $227 million (2003 – $390 million) and US$157 million (2003 – US$282 million). The carrying amount and fair value of these interest rate swaps was $(4) million (2003 – nil) and $(4) million (2003 – $6 million), respectively.

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)		2004		2003	
December 31 (millions of dollars)	Accounting Treatment	**Fair Value**	**Notional or Notional Principal Amount**	Fair Value	Notional or Notional Principal Amount
Foreign Exchange					
Options (maturing 2005)	Non-hedge	**2**	**U.S. 225**	1	U.S. 25
Forward foreign exchange contracts (maturing 2005)	Non-hedge	**1**	**U.S. 29**	1	U.S. 19
Cross-currency swaps (maturing 2013)	Hedge	**(16)**	**U.S. 100**	(7)	U.S. 100
Interest Rate					
Options (maturing 2005)	Non-hedge	**–**	**U.S. 50**	(2)	U.S. 50
Interest rate swaps					
Canadian dollar					
(maturing 2007 to 2009)	Hedge	**4**	**100**	2	50
(maturing 2005 to 2011)	Non-hedge	**1**	**110**	2	100
		5		4	
U.S. dollar					
(maturing 2006 to 2013)	Hedge	**5**	**U.S. 100**	40	U.S. 250
(maturing 2006 to 2010)	Non-hedge	**22**	**U.S. 250**	(3)	U.S. 200
		27		37	

In accordance with the Company's accounting policy, each of the above derivatives is recorded on the consolidated balance sheet at its fair value in 2004. At December 31, 2004, the Company also had interest rate swaps associated with the cross-currency swaps with notional principal amounts of $136 million (2003 – $136 million) and US$100 million (2003 – US$100 million). The carrying amount and fair value of these interest rate swaps was $(10) million (2003 – nil) and $(10) million (2003 – $(7) million), respectively.

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, 2004 was $1 million (2003 – $(1) million).

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 values and notional volumes of the swap, option, forward and heat rate contracts are shown in the tables below. In accordance with the Company's accounting policy, each of the derivatives in the table below is recorded on the balance sheet at its fair value in 2004 and 2003.

Power

Asset/(Liability)		2004	2003
December 31 (millions of dollars)	Accounting Treatment	**Fair Value**	Fair Value
Power – swaps			
(maturing 2005 to 2011)	Hedge	**7**	(5)
(maturing 2005)	Non-hedge	**(2)**	–
Gas – swaps, forwards and options			
(maturing 2005 to 2016)	Hedge	**(39)**	(34)
(maturing 2005)	Non-hedge	**(2)**	(1)
Heat rate contracts			
(maturing 2005 to 2006)	Hedge	**(1)**	(1)

Notional Volumes		Power (GWh) (1)		Gas (Bcf) (1)	
December 31, 2004	Accounting Treatment	**Purchases**	**Sales**	**Purchases**	**Sales**
Power – swaps					
(maturing 2005 to 2011)	Hedge	**3,314**	**7,029**	**–**	**–**
(maturing 2005)	Non-hedge	**438**	**–**	**–**	**–**
Gas – swaps, forwards and options					
(maturing 2005 to 2016)	Hedge	**–**	**–**	**80**	**84**
(maturing 2005)	Non-hedge	**–**	**–**	**5**	**8**
Heat rate contracts					
(maturing 2005 to 2006)	Hedge	**–**	**229**	**2**	**–**
December 31, 2003					
Power – swaps	Hedge	1,331	4,787	–	–
	Non-hedge	59	77	–	–
Gas – swaps, forwards and options	Hedge	–	–	79	81
	Non-hedge	–	–	–	7
Heat rate contracts	Hedge	–	735	1	–

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

U.S. Dollar Transaction Hedges To reduce risk and protect margins when purchase and sale contracts are denominated in different currencies, the Company may enter into forward foreign exchange contracts and foreign exchange options which establish the foreign exchange rate for the cash flows from the related purchase and sale transactions.

Other Fair Values	**2004**		2003	
December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Long-Term Debt				
Canadian Mainline	**4,445**	**5,473**	4,853	5,922
Alberta System	**2,105**	**2,668**	2,325	2,893
GTN (1)	**632**	**627**		
Foothills System	**400**	**413**	380	382
Portland	**308**	**328**	350	348
Other	**2,589**	**2,687**	2,107	2,214
Non-Recourse Debt of Joint Ventures	**862**	**967**	780	889
Preferred Securities	**19**	**19**	19	19

(1) TransCanada acquired GTN on November 1, 2004.

These fair values are provided solely for information purposes and are not recorded in the consolidated balance sheet.

NOTE 15 Income Taxes

Provision for Income Taxes

Year ended December 31 (millions of dollars)	2004	2003	2002
Current			
Canada	**390**	264	229
Foreign	**41**	41	41
	431	305	270
Future			
Canada	**34**	183	193
Foreign	**43**	47	54
	77	230	247
	508	535	517

Geographic Components of Income

Year ended December 31 (millions of dollars)	2004	2003	2002
Canada	**1,255**	1,115	1,042
Foreign	**296**	281	280
Income from continuing operations before income taxes and non-controlling interests	**1,551**	1,396	1,322

Reconciliation of Income Tax Expense

Year ended December 31 (millions of dollars)	2004	2003	2002
Income from continuing operations before income taxes and non-controlling interests	**1,551**	1,396	1,322
Federal and provincial statutory tax rate	**33.9%**	36.7%	39.2%
Expected income tax expense	**526**	512	518
Income tax differential related to regulated operations	**62**	29	(8)
Higher (lower) effective foreign tax rates	**2**	(2)	(13)
Large corporations tax	**21**	28	30
Lower effective tax rate on equity in earnings of affiliates	**(9)**	(11)	(2)
Non-taxable portion of gains related to Power LP	**(66)**	–	–
Change in valuation allowance	**(7)**	(3)	8
Other	**(21)**	(18)	(16)
Actual income tax expense	**508**	535	517

Future Income Tax Assets and Liabilities

December 31 (millions of dollars)	2004	2003
Deferred costs	**71**	50
Deferred revenue	**18**	29
Alternative minimum tax credits	**10**	29
Net operating and capital loss carryforwards	**7**	28
Other	**72**	24
	178	160
Less: Valuation allowance	**17**	24
Future income tax assets, net of valuation allowance	**161**	136
Difference in accounting and tax bases of plant, equipment and PPAs	**456**	396
Investments in subsidiaries and partnerships	**114**	108
Unrealized foreign exchange gains on long-term debt	**45**	15
Other	**55**	44
Future income tax liabilities	**670**	563
Net future income tax liabilities	**509**	427

As permitted by Canadian GAAP, the Company follows the taxes payable method of accounting for income taxes related to the operations of the Canadian natural gas transmission operations. If the liability method of accounting had been used, additional future income tax liabilities in the amount of $1,692 million at December 31, 2004 (2003 – $1,758 million) would have been recorded and would be recoverable from future revenues.

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 $57 million at December 31, 2004 (2003 – $54 million).

Income Tax Payments Income tax payments of $419 million were made during the year ended December 31, 2004 (2003 – $220 million; 2002 – $257 million).

NOTE 16 Notes Payable

	2004		2003	
	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)	
Commercial Paper				
Canadian dollars	**546**	**2.6%**	367	2.7%

Total credit facilities of $2.0 billion at December 31, 2004, were available to support the Company's commercial paper programs and for general corporate purposes. Of this total, $1.5 billion is a committed syndicated credit facility established in December 2002. This facility is comprised of a $1.0 billion tranche with a five year term and a $500 million tranche with a 364 day term with a two year term out option. Both tranches are extendible on an annual basis and are revolving unless during a term out period. Both tranches were extended in December 2004, the $1.0 billion tranche to December 2009 and the $500 million tranche to December 2005. The remaining amounts are either demand or non-extendible facilities.

At December 31, 2004, the Company had used approximately $61 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 would be 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 is approximately $2 million for the year ended December 31, 2004 (2003 – $2 million).

NOTE 17 Asset Retirement Obligations

At December 31, 2004, the estimated undiscounted cash flows required to settle the asset retirement obligation with respect to Gas Transmission were $48 million, calculated using an inflation rate of 3 per cent per annum, and the estimated fair value of this liability was $12 million (2003 – $2 million). The estimated cash flows have been discounted at rates ranging from 6.0 per cent to 6.6 per cent. At December 31, 2004, the expected timing of payment for settlement of the obligations ranges from 13 to 25 years. No amount has been 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 indeterminate timing and scope 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.

At December 31, 2004, the estimated undiscounted cash flows required to settle the asset retirement obligation with respect to the Power business were $128 million, calculated using an inflation rate of 3 per cent per annum, and the estimated fair value of this liability was $24 million (2003 – $7 million). The estimated cash flows have been discounted at rates ranging from 6.0 per cent to 6.6 per cent. At December 31, 2004, the expected timing of payment for settlement of the obligations ranges from 17 to 29 years.

Reconciliation of Asset Retirement Obligations

(millions of dollars)	Gas Transmission	Power	Total
Balance at December 31, 2002	2	6	8
Revisions in estimated cash flows	–	1	1
Balance at December 31, 2003	2	7	9
New obligations and revisions in estimated cash flows	**9**	**21**	**30**
Removal of Power LP redemption obligations	**–**	**(5)**	**(5)**
Accretion expense	**1**	**1**	**2**
Balance at December 31, 2004	**12**	**24**	**36**

NOTE 18 Employee Future Benefits

The Company sponsors DB Plans that cover substantially all employees and sponsored a defined contribution pension plan (DC Plan) which was effectively terminated at December 31, 2002. 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. Under the DC Plan, Company contributions were based on the participating employees' pensionable earnings. As a result of the termination of the DC Plan, members of this plan were awarded retroactive service credit under the DB Plans for all years of service. In exchange for past service credit, members surrendered the accumulated assets in their DC Plan accounts to the DB Plans as at December 31, 2002. This plan amendment resulted in unamortized past service costs of $44 million. 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 other post-employment benefits other than pensions, including termination benefits and defined life insurance and medical benefits beyond those provided by government-sponsored plans. Effective January 1, 2003, the Company combined its previously existing other post-employment benefit plans into one plan for active employees and provided existing retirees the option of adopting the provisions of the new plan. This plan amendment resulted in unamortized past service costs of $7 million. Past service costs are amortized over the expected average remaining life expectancy of former employees, which is approximately 19 years.

The expense for the DC Plan was nil for the year ended December 31, 2004 (2003 – nil; 2002 – $6 million). In 2004, the Company also expensed $1 million (2003 – $1 million; 2002 – nil) related to retirement savings plans for its U.S. employees.

Total cash payments for employee future benefits for 2004, consisting of cash contributed by the Company to the DB Plans and other benefit plans was $88 million (2003 – $114 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, 2005, and the next required valuation will be as of January 1, 2006.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2004**	2003	**2004**	2003
Change in Benefit Obligation				
Benefit obligation – beginning of year	**960**	841	**106**	95
Current service cost	**28**	25	**3**	2
Interest cost	**58**	52	**7**	6
Employee contributions	**2**	2	**–**	–
Benefits paid	**(66)**	(45)	**(4)**	(4)
Actuarial loss	**46**	66	**(12)**	7
Acquisition of subsidiary	**72**	19	**23**	–
Benefit obligation – end of year	**1,100**	960	**123**	106
Change in Plan Assets				
Plan assets at fair value – beginning of year	**799**	621	**–**	–
Actual return on plan assets	**97**	89	**1**	–
Employer contributions	**84**	110	**4**	4
Employee contributions	**2**	2	**–**	–
Benefits paid	**(66)**	(45)	**(4)**	(4)
Acquisition of subsidiary	**54**	22	**25**	–
Plan assets at fair value – end of year	**970**	799	**26**	–
Funded status – plan deficit	**(130)**	(161)	**(97)**	(106)
Unamortized net actuarial loss	**255**	263	**25**	39
Unamortized past service costs	**39**	41	**7**	6
Unamortized transitional obligation related to regulated business	**–**	–	**–**	25
Accrued benefit asset/(liability), net of valuation allowance of nil	**164**	143	**(65)**	(36)

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

	Pension Benefit Plans		Other Benefit Plans	
	2004	2003	**2004**	2003
Other assets	**206**	201	**3**	–
Accounts payable	**(42)**	(58)	**(5)**	(4)
Deferred amounts	**–**	–	**(63)**	(32)
Total	**164**	143	**(65)**	(36)

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

	Pension Benefit Plans		Other Benefit Plans	
	2004	2003	**2004**	2003
Accrued benefit obligation	**(1,084)**	(942)	**(100)**	(106)
Fair value of plan assets	**952**	778	**–**	–
Funded status – plan deficit	**(132)**	(164)	**(100)**	(106)

The Company's expected contributions for the year ended December 31, 2005 are approximately $67 million for the pension benefit plans and approximately $6 million for the other benefit plans.

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

(millions of dollars)	Pension Benefits	Other Benefits
2005	52	6
2006	53	6
2007	56	7
2008	58	7
2009	60	7
Years 2010 to 2014	343	40

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	
	2004	2003	**2004**	2003
Discount rate	**5.75%**	6.00%	**6.00%**	6.25%
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		
	2004	2003	2002	**2004**	2003	2002
Discount rate	**6.00%**	6.25%	6.75%	**6.25%**	6.50%	6.85%
Expected long-term rate of return on plan assets	**6.90%**	7.25%	7.52%			
Rate of compensation increase	**3.50%**	3.75%	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.

For measurement purposes, a 9.0 per cent annual rate of increase in the per capita cost of covered health care benefits was assumed for 2005. The rate was assumed to decrease gradually to 5.0 per cent for 2014 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	2	(1)
Effect on post-employment benefit obligation	12	(11)

The Company's net benefit cost is as follows.

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31 (millions of dollars)	**2004**	2003	2002	**2004**	2003	2002
Current service cost	**28**	25	11	**3**	2	2
Interest cost	**58**	52	43	**7**	6	4
Actual return on plan assets	**(97)**	(89)	(9)	**1**	–	–
Actuarial loss	**46**	66	93	**(12)**	7	26
Plan amendment	**–**	–	92	**–**	–	7
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**35**	54	230	**(1)**	15	39
Difference between expected and actual return on plan assets	**39**	38	(36)	**(1)**	–	–
Difference between actuarial loss recognized and actual actuarial loss on accrued benefit obligation	**(32)**	(58)	(91)	**13**	(6)	(26)
Difference between amortization of past service costs and actual plan amendments	**3**	3	(92)	**–**	1	(7)
Amortization of transitional obligation related to regulated business	**–**	–	–	**2**	2	2
Net benefit cost recognized	**45**	37	11	**13**	12	8

The Company's pension plan weighted average asset allocation 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	**2004**	2003	**2004**
Debt securities	**44%**	47%	**35% to 60%**
Equity securities	**56%**	53%	**40% to 65%**
	100%	100%	

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

NOTE 19 Changes in Operating Working Capital

Year ended December 31 (millions of dollars)	**2004**	2003	2002
Decrease/(increase) in accounts receivable	**9**	26	(45)
Decrease/(increase) in inventories	**–**	15	(3)
Decrease/(increase) in other current assets	**33**	21	(53)
(Decrease)/increase in accounts payable	**(1)**	52	120
(Decrease)/increase in accrued interest	**(7)**	(2)	14
	34	112	33

NOTE 20 Commitments, Contingencies and Guarantees

Commitments Future annual payments, net of sub-lease receipts, under the Company's operating leases for various premises 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
2005	37	(9)	28
2006	45	(10)	35
2007	51	(9)	42
2008	53	(9)	44
2009	53	(9)	44

The operating lease agreements for premises expire at various dates through 2011, with an option to renew certain lease agreements for 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, 2004 was $7 million (2003 – $2 million; 2002 – $7 million).

On June 18, 2003, the Mackenzie Delta gas producers, the Aboriginal Pipeline Group (APG) and TransCanada reached an agreement which governs TransCanada's role in the Mackenzie Gas Pipeline 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. This share is currently estimated to be approximately $90 million. As at December 31, 2004, TransCanada had funded $60 million of this loan (2003 – $34 million) which is included in other assets. The ability to recover this investment is dependent upon the outcome of the project.

Contingencies The Canadian Alliance of Pipeline Landowners' Associations 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. The Company believes 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 Upon acquisition of Bruce Power, the Company, together with Cameco Corporation and BPC Generation Infrastructure Trust, guaranteed on a several pro-rata basis certain contingent financial obligations of Bruce Power related to operator licenses, the lease agreement, power sales agreements and contractor services. TransCanada's share of the net exposure under these guarantees at December 31, 2004 was estimated to be approximately $158 million of a maximum of $293 million. The terms of the guarantees range from 2005 to 2018. The current carrying amount of the liability related to these guarantees is nil and the fair value is approximately $9 million.

TransCanada has guaranteed the equity undertaking of a subsidiary which supports the payment, under certain conditions, of principal and interest on US$161 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. 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. The escrowed funds represent the full face amount of the potential liability under certain GTN guarantees and are to be used to satisfy the liability under these designated guarantees.

NOTE 21 Discontinued Operations

The Board of Directors approved plans in previous years to dispose of the Company's International, Canadian Midstream, Gas Marketing and certain other businesses. Revenues from discontinued operations for the year ended December 31, 2004 were nil (2003 – $2 million; 2002 – $36 million). Net income from discontinued operations for the year ended December 31, 2004 was $52 million, net of $27 million of income taxes (2003 – $50 million, net of $29 million of income taxes; 2002 – nil). The net income from discontinued operations recognized in 2003 and 2004 represents the original $102 million after-tax deferred gain on the disposition of certain of the Gas Marketing operations. Included in accounts payable at December 31, 2004 was the remaining $55 million provision for loss on discontinued operations.

NOTE 22 U.S. GAAP

The Company's consolidated financial statements have been prepared in accordance with Canadian GAAP, which, in some respects, differ from U.S. GAAP. The effects of these differences on the Company's financial statements are as follows.

Condensed Statement of Consolidated Income and Comprehensive Income in Accordance with U.S. GAAP (1)

Year ended December 31 (millions of dollars except per share amounts)	**2004**	2003	2002
Revenues	**4,700**	4,919	4,565
Cost of sales	**440**	592	441
Other costs and expenses	**1,638**	1,663	1,532
Depreciation	**857**	819	729
	2,935	3,074	2,702
Operating income	**1,765**	1,845	1,863
Other (income)/expenses			
Equity income (1)	**(353)**	(334)	(260)
Other expenses (2)	**651**	863	872
Income taxes	**490**	515	499
	788	1,044	1,111
Income from continuing operations – U.S. GAAP	**977**	801	752
Net income from discontinued operations – U.S. GAAP	**52**	50	–
Income before cumulative effect of the application of accounting changes in accordance with U.S. GAAP	**1,029**	851	752
Cumulative effect of the application of accounting changes, net of tax (3)	**–**	(13)	–
Net Income in Accordance with U.S. GAAP	**1,029**	838	752
Adjustments affecting comprehensive income under U.S. GAAP			
Foreign currency translation adjustment, net of tax	**(31)**	(54)	1
Changes in minimum pension liability, net of tax (4)	**72**	(2)	(40)
Unrealized gain/(loss) on derivatives, net of tax (5)	**1**	8	(4)
Comprehensive Income in Accordance with U.S. GAAP	**1,071**	790	709
Net Income Per Share in Accordance with U.S. GAAP			
Continuing operations	**$ 2.02**	$ 1.67	$ 1.57
Discontinued operations	**0.11**	0.10	–
Income before cumulative effect of the application of accounting changes in accordance with U.S. GAAP	**$ 2.13**	$ 1.77	$ 1.57
Cumulative effect of the application of accounting changes, net of tax (3)	**–**	(0.03)	–
Basic	**$ 2.13**	$ 1.74	$ 1.57
Diluted (6)	**$ 2.12**	$ 1.73	$ 1.56
Net Income Per Share in Accordance with Canadian GAAP			
Basic	**$ 2.13**	$ 1.76	$ 1.56
Diluted	**$ 2.12**	$ 1.76	$ 1.55
Dividends per common share	**$ 1.16**	$ 1.08	$ 1.00

Reconciliation of Income from Continuing Operations

Year ended December 31 (millions of dollars)	**2004**	2003	2002
Net Income from Continuing Operations in Accordance with Canadian GAAP	**980**	801	747
U.S. GAAP adjustments			
Unrealized (loss)/gain on foreign exchange and interest rate derivatives (5)	**(12)**	(9)	30
Tax impact of (loss)/gain on foreign exchange and interest rate derivatives	**4**	3	(12)
Unrealized gain/(loss) on energy marketing contracts (3)	**10**	28	(21)
Tax impact of unrealized gain/(loss) on energy marketing contracts	**(3)**	(10)	8
Equity loss (7)	**(2)**	(18)	–
Tax impact of equity loss	**–**	6	–
Income from Continuing Operations in Accordance with U.S. GAAP	**977**	801	752

Condensed Statement of Consolidated Cash Flows in Accordance with U.S. GAAP

Year ended December 31 (millions of dollars)	**2004**	2003	2002
Cash Generated from Operations			
Funds generated from continuing operations	**1,529**	1,619	1,610
Decrease in operating working capital	**45**	108	40
Net cash provided by continuing operations	**1,574**	1,727	1,650
Net cash (used in)/provided by discontinued operations	**(6)**	(17)	59
	1,568	1,710	1,709
Investing Activities			
Net cash used in investing activities	**(1,304)**	(943)	(796)
Financing Activities			
Net cash used in financing activities	**(336)**	(581)	(990)
Effect of Foreign Exchange Rate Changes on Cash and Short-Term Investments	**(87)**	(52)	(3)
(Decrease)/Increase in Cash and Short-Term Investments	**(159)**	134	(80)
Cash and Short-Term Investments			
Beginning of year	**283**	149	229
Cash and Short-Term Investments			
End of year	**124**	283	149

Condensed Balance Sheet in Accordance with U.S. GAAP (1)

December 31 (millions of dollars)	**2004**	2003
Current assets	**908**	1,020
Long-term investments (7)(8)	**1,887**	1,760
Plant, property and equipment	**17,083**	15,753
Regulatory asset (9)	**2,606**	2,721
Other assets	**1,235**	1,385
	23,719	22,639
Current liabilities (10)	**2,573**	2,135
Deferred amounts (3)(5)(8)	**803**	827
Long-term debt (5)	**9,753**	9,494
Deferred income taxes (9)	**3,048**	3,039
Preferred securities (11)	**554**	694
Non-controlling interests	**465**	471
Shareholders' equity	**6,523**	5,979
	23,719	22,639

Statement of Other Comprehensive Income in Accordance with U.S. GAAP

(millions of dollars)	Cumulative Translation Account	Minimum Pension Liability (SFAS No. 87)	Cash Flow Hedges (SFAS No. 133)	Total
Balance at January 1, 2002	13	(56)	(9)	(52)
Changes in minimum pension liability, net of tax of $22 (4)	–	(40)	–	(40)
Unrealized loss on derivatives, net of tax of $(1) (5)	–	–	(4)	(4)
Foreign currency translation adjustment, net of tax of nil	1	–	–	1
Balance at December 31, 2002	14	(96)	(13)	(95)
Changes in minimum pension liability, net of tax of $1 (4)	–	(2)	–	(2)
Unrealized gain on derivatives, net of tax of nil (5)	–	–	8	8
Foreign currency translation adjustment, net of tax of $(64)	(54)	–	–	(54)
Balance at December 31, 2003	(40)	(98)	(5)	(143)
Changes in minimum pension liability, net of tax of $(39) (4)	**–**	**72**	**–**	**72**
Unrealized gain on derivatives, net of tax of $(3) (5)	**–**	**–**	**1**	**1**
Foreign currency translation adjustment, net of tax of $(44)	**(31)**	**–**	**–**	**(31)**
Balance at December 31, 2004	**(71)**	**(26)**	**(4)**	**(101)**

(1) In accordance with U.S. GAAP, the Condensed Statement of Consolidated Income and Balance Sheet are prepared using the equity method of accounting for joint ventures. Excluding the impact of other U.S. GAAP adjustments, the use of the proportionate consolidation method of accounting for joint ventures, as required under Canadian GAAP, results in the same net income and shareholders' equity.

(2) Other expenses included an allowance for funds used during construction of $3 million for the year ended December 31, 2004 (2003 – $2 million; 2002 – $4 million).

(3) Subsequent to October 1, 2003, the energy contracts that were accounted for as hedges under the provisions of Statement of Financial Accounting Standards (SFAS) No. 133 qualified as hedges. Substantially all derivative energy contracts are now accounted for as hedges under both U.S. and Canadian GAAP. All gains or losses on the contracts that did not qualify as hedges under SFAS No. 133, and the amounts of any ineffectiveness on the hedging contracts, are included in income each period. Substantially all of the amounts recorded in 2004 and 2003 as differences between U.S. and Canadian GAAP relate to gains and losses on contracts for periods before they were documented as hedges for purposes of U.S. GAAP and to differences in accounting with respect to physical energy trading contracts in the U.S. and Canada.

(4) Under U.S. GAAP, a net loss recognized pursuant to SFAS No. 87 "Employers' Accounting for Pensions" as an additional pension liability not yet recognized as net period pension cost, must be recorded as a component of comprehensive income. The net amount recognized at December 31 is as follows.

December 31 (millions of dollars)	**2004**	2003
Prepaid benefit cost	**206**	201
Accounts payable	**(42)**	(58)
Intangible assets	**(1)**	(41)
Accumulated other comprehensive income	**(40)**	(151)
Net amount recognized	**123**	(49)

The accumulated benefit obligation for the Company's DB Plans was $943 million at December 31, 2004 (2003 – $819 million).

(5) Effective January 1, 2004, all foreign exchange and interest rate derivatives are recorded in the Company's consolidated financial statements at fair value under Canadian GAAP. Under the provisions of SFAS No. 133 "Accounting for Derivatives and Hedging Activities", all derivatives are recognized as assets and liabilities on the balance sheet and measured at fair value. For derivatives designated as fair value hedges, changes in the fair value are recognized in earnings together with an equal or lesser amount of changes in the fair value of the hedged item attributable to the hedged risk. For derivatives designated as cash flow hedges, changes in the fair value of the derivative that are effective in offsetting the hedged risk are recognized in other comprehensive income until the hedged item is recognized in earnings. Any ineffective portion of the change in fair value is recognized in earnings each period. Substantially all of the amounts recorded in 2004 as differences between U.S. and Canadian GAAP, for income from continuing operations, relate to the differences in accounting treatment with respect to the hedged item and, for comprehensive income, relate to cash flow hedges.

During 2004, under the provisions of SFAS 133, net gains of $10 million (2003 – $47 million; 2002 – $38 million) from the hedges of changes in the fair value of long-term debt, and net losses of $18 million (2003 – $53 million; 2002 – $20 million) in the fair value of the hedged item were included in earnings for U.S. GAAP purposes as an adjustment to interest expense and foreign exchange losses. No amounts of the derivatives' gains or losses were excluded from the assessment of hedge effectiveness in fair value hedging relationships.

No amounts were included in income in 2004, 2003 and 2002 with respect to ineffectiveness of cash flow hedges. For amounts included in other comprehensive income at December 31, 2004, $2 million (2003 – $9 million; 2002 – $(5) million) relates to the hedging of interest rate risk, $(3) million (2003 – $5 million; 2002 – $1 million) relates to the hedging of foreign exchange rate risk, and $2 million (2003 – $(6) million; 2002 – nil) relates to the hedging of energy price risk. Of these amounts, $2 million is expected to be recorded in earnings during 2005.

At December 31, 2004, assets of $(29) million (2003 – $91 million) and liabilities of $(27) million (2003 – $93 million) were (reduced)/added for U.S. GAAP purposes to reflect the fair value of derivatives and the corresponding change in the fair value of hedged items.

(6) Diluted net income per share in accordance with U.S. GAAP for the year ended December 31, 2004 consists of continuing operations – $2.01 per share (2003 – $1.63 per share; 2002 – $1.56 per share), and discontinued operations – $0.11 per share (2003 – $0.10 per share; 2002 – nil).

(7) Under Canadian GAAP, pre-operating costs incurred during the commissioning phase of a new project are deferred until commercial production levels are achieved. After such time, those costs are amortized over the estimated life of the project. Under U.S. GAAP, such costs are expensed as incurred. Certain start-up costs incurred by Bruce Power, L.P. (an equity investment) are required to be expensed under U.S. GAAP.

Under both Canadian GAAP and U.S. GAAP, interest is capitalized on expenditures relating to construction of development projects actively being prepared for their intended use. In Bruce Power, L.P. under U.S. GAAP, the carrying value of development projects against which interest is capitalized is lower due to the expensing of pre-operating costs.

(8) Effective January 1, 2003, the Company adopted the provisions of Financial Interpretation (FIN) 45 that require the recognition of a liability for the fair value of certain guarantees that require payments contingent on specified types of future events. The measurement standards of FIN 45 are applicable to guarantees entered into after January 1, 2003. For U.S. GAAP purposes, the fair value of guarantees recorded as a liability at December 31, 2004 was $9 million (2003 – $4 million) and relates to the Company's equity interest in Bruce Power.

(9) Under U.S. GAAP, the Company is required to record a deferred income tax liability for its cost-of-service regulated businesses. As these deferred income taxes are recoverable through future revenues, a corresponding regulatory asset is recorded for U.S. GAAP purposes.

(10) Current liabilities at December 31, 2004 include dividends payable of $146 million (2003 – $136 million) and current taxes payable of $260 million (2003 – $271 million).

(11) The fair value of the preferred securities at December 31, 2004 was $572 million (2003 – $612 million). The Company made preferred securities charges payments of $48 million for the year ended December 31, 2004 (2003 – $57 million; 2002 – $58 million).

Income Taxes The tax effects of differences between the accounting value and the tax value of assets and liabilities are as follows.

December 31 (millions of dollars)	**2004**	2003
Deferred Tax Liabilities		
Difference in accounting and tax bases of plant, equipment and PPAs	**1,741**	1,813
Taxes on future revenue requirement	**914**	962
Investments in subsidiaries and partnerships	**438**	373
Other	**140**	87
	3,233	3,235
Deferred Tax Assets		
Net operating and capital loss carryforwards	**7**	28
Deferred amounts	**89**	79
Other	**106**	113
	202	220
Less: Valuation allowance	**17**	24
	185	196
Net deferred tax liabilities	**3,048**	3,039

Other Effective December 31, 2003, the Company adopted the provisions of FIN 46 (Revised) "Consolidation of Variable Interest Entities" that requires the consolidation of certain entities that are controlled through financial interests that indicate control (referred to as 'variable interests'). Adopting these provisions has had no impact on the U.S. GAAP financial statements of the Company.

In May 2003, the FASB issued SFAS No. 150 "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity". This statement establishes standards for how an issuer classifies and measures in its statement of financial position certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances) because that financial instrument embodies an obligation of the issuer. Many of those instruments were previously classified as equity. Adopting the provisions of SFAS No. 150 has had no impact on the U.S. GAAP financial statements of the Company.

Summarized Financial Information of Long-Term Investments

The following summarized financial information of long-term investments includes those investments that are accounted for by the equity method under U.S. GAAP (including those that are accounted for by the proportionate consolidation method under Canadian GAAP).

Year ended December 31 (millions of dollars)	**2004**	2003	2002
Income			
Revenues	**1,149**	1,063	798
Other costs and expenses	**(575)**	(528)	(273)
Depreciation	**(155)**	(141)	(146)
Financial charges and other	**(66)**	(60)	(119)
Proportionate share of income before income taxes of long-term investments	**353**	334	260

December 31 (millions of dollars)	**2004**	2003
Balance Sheet		
Current assets	**361**	385
Plant, property and equipment	**3,020**	2,944
Current liabilities	**(248)**	(204)
Deferred amounts (net)	**(199)**	(286)
Non-recourse debt	**(1,030)**	(1,060)
Deferred income taxes	**(17)**	(19)
Proportionate share of net assets of long-term investments	**1,887**	1,760