Management's Discussion and Analysis

DISCIPLINED

APPROACH

The Management's Discussion and Analysis dated February 24, 2004 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, 2003.

CONSOLIDATED FINANCIAL REVIEW

HIGHLIGHTS

Earnings Increase TransCanada's net income from continuing operations (net earnings) increased $54 million or seven per cent to $801 million or $1.66 per share in 2003 compared to $747 million or $1.56 per share in 2002.

Balance Sheet Strengthened In 2003, TransCanada's balance sheet continued to strengthen as shareholders' equity increased by $344 million.

Dividend Increase On January 27, 2004, the Board of Directors of TransCanada raised the quarterly dividend on the company's outstanding common shares seven per cent from $0.27 per share to $0.29 per share for the quarter ending March 31, 2004.

Growth in Core Businesses In 2003, TransCanada invested more than $1.2 billion, including the assumption of debt, in the Gas Transmission and Power businesses.

Consolidated Results-at-a-Glance

Year ended December 31 (millions of dollars except per share amounts)	**2003**	2002	2001
Net Income/(Loss)			
Continuing operations	**801**	747	686
Discontinued operations	**50**	–	(67)
	851	747	619
Net Income/(Loss) Per Share – Basic			
Continuing operations	**$ 1.66**	$ 1.56	$ 1.44
Discontinued operations	**0.10**	–	(0.14)
	$ 1.76	$ 1.56	$ 1.30

Net income for the year ended December 31, 2003 of $851 million or $1.76 per share included net income from discontinued operations of $50 million or $0.10 per share, which reflected the income recognition of $50 million of the initially deferred gain of approximately $100 million after tax relating to the 2001 disposition of the company's Gas Marketing business. This compares to net income in 2002 of $747 million or $1.56 per share and net income in 2001 of $619 million or $1.30 per share, which included a net loss from discontinued operations of $67 million or $0.14 per share.

Segment Results-at-a-Glance

Year ended December 31 (millions of dollars)	**2003**	2002	2001
Gas Transmission	**622**	653	585
Power	**220**	146	168
Corporate	**(41)**	(52)	(67)
Continuing operations	**801**	747	686
Discontinued operations	**50**	–	(67)
Net Income	**851**	747	619

TransCanada's net earnings for the year ended December 31, 2003 were $801 million or $1.66 per share compared to $747 million or $1.56 per share in 2002 and $686 million or $1.44 per share in 2001. The increase of $54 million in 2003 compared to 2002 was 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.

The increase in 2002 net earnings compared to 2001 was due to higher earnings from the Gas Transmission business and reduced expenses in the Corporate segment, partially offset by lower earnings from the Power segment. The Power segment earnings in 2001 reflected the company's ability to capture significant market opportunities created by high market prices and power price volatility.

Net earnings from the Power business for the year ended December 31, 2003 included $73 million after tax from TransCanada's investment in Bruce Power L.P. (Bruce Power) which was acquired in February 2003 and a $19 million positive after-tax earnings impact of a June 2003 settlement with a former counterparty which defaulted in 2001 under power forward contracts. These increases were partially offset by reduced operating and other income from the Power segment's Eastern Operations, combined with higher general, administrative and support costs.

The decrease in net expenses of $11 million in the Corporate segment in 2003 was primarily due to the positive impacts of a weaker U.S. dollar in 2003 compared to 2002.

The reduction in net earnings of $31 million in the Gas Transmission business for the year ended December 31, 2003 compared to 2002 was primarily due to the decline in the Alberta System's 2003 net earnings, reflecting the one-year fixed revenue requirement settlement reached between TransCanada and its customers in February 2003. Also, in June 2002, TransCanada received the National Energy Board (NEB) decision on its Fair Return application (Fair Return decision) to determine the cost of capital to be included in the calculation of 2001 and 2002 tolls on the Canadian Mainline. The results for the year ended December 31, 2002 included after-tax income of $16 million, which represents the impact of the Fair Return decision for 2001. The 2003 results for the Gas Transmission segment included TransCanada's $11 million share of a future income tax benefit adjustment recognized by TransGas de Occidente S.A. (TransGas), while the 2002 results included TransCanada's $7 million share of a favourable ruling for Great Lakes Gas Transmission Limited Partnership (Great Lakes) 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 year ended December 31, 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 years ended December 31, 2002 and 2001 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. At December 31, 2003, the Gas Transmission business accounted for approximately 86 per cent and Power approximately 14 per cent of total operating assets of $19.7 billion. In 2003, the Gas Transmission and Power businesses delivered net earnings of $622 million and $220 million, respectively.

The Gas Transmission and Power businesses have similar characteristics and business drivers. Infrastructure such as natural gas pipelines and power generation are both driven by similar supply and demand fundamentals and these markets are highly interdependent. Both businesses are capital intensive, employ many similar technologies and operating practices, and require financial strength and stability to support the capital required.

Gas Transmission The Gas Transmission segment includes the operation of four wholly-owned regulated natural gas pipelines: the Canadian Mainline, the Alberta System, the Foothills System and the BC System. TransCanada's investments in Other Gas Transmission principally include the partial ownership of one Canadian pipeline, five United States pipelines and a 33.4 per cent interest in TC PipeLines, LP, a publicly held U.S. limited partnership of which TransCanada is the general partner. In 2003, the Gas Transmission business transported 66 per cent of the natural gas produced in the Western Canada Sedimentary Basin (WCSB), 65 per cent of which was exported to the U.S.

Power TransCanada's Power segment is primarily focused on power generation and includes the construction, ownership, operation and management of electrical power generation plants, with a total of 4,667 megawatts (MW) of generating capacity. To generate electricity, the company uses various fuel sources such as natural gas, waste heat, wood waste, coal, nuclear and hydro. TransCanada also markets electricity in order to optimize the asset value of the company's power generation portfolio. Power's portfolio includes eight wholly-owned plants in operation, a 31.6 per cent equity interest in the Bruce Power nuclear facility and the power production from two power facilities in Alberta through power purchase arrangements (PPAs). In addition, there is one plant in the permitting phase and another under construction. TransCanada also holds a 35.6 per cent interest in, and is the general partner of, TransCanada Power, L.P. (Power LP), a publicly traded limited partnership that owns seven power plants.

TRANSCANADA'S STRATEGY

TransCanada's goal is to be the most profitable, competitive and reliable provider of natural gas transportation and power services in North America.

TransCanada has five key strategies for achieving its goal:

- Sustain, grow and optimize the natural gas transmission business by connecting new WCSB supply, Northern gas and liquefied natural gas (LNG) to growing markets.
- Continue to work with regulators and customers to evolve the regulated business model to allow TransCanada to earn competitive returns and compete in a North American market.
- Grow and optimize the power business.
- Continue to pursue an operationally excellent business model to ensure better, faster and cost effective delivery of natural gas and generation of power to customers.
- Maintain and effectively utilize the company's strong financial position to capitalize on growth opportunities when they arise.

GAS TRANSMISSION

Opportunities North American natural gas demand is expected to grow to 85 billion cubic feet per day (Bcf/d) by 2015 from 70 Bcf/d in 2002, an increase of 21 per cent over this time period. While higher natural gas prices may result in some demand destruction or fuel switching, TransCanada expects that in the long term, demand for natural gas will increase substantially. Flat to slightly increasing production is expected in existing natural gas production basins as a result of higher natural gas prices leading to increased drilling, offset by higher decline rates and lower initial well production rates. Overall, supply from traditional North American basins is expected to grow by 1 Bcf/d by 2015. These expectations indicate that North America will require substantial incremental volumes of natural gas from non-traditional sources to meet the increased demand. This incremental natural gas supply is expected to come from frontier regions such as Alaska and Canada's Mackenzie Delta, as well as from new LNG opportunities. TransCanada will continue to pursue growth of the current infrastructure and develop new infrastructure linking new supply to growing markets.

Today, TransCanada owns the largest pipeline network that links the WCSB with significant growing markets in North America. In 2003, the Alberta System gathered approximately 11 Bcf/d, representing 66 per cent of the natural gas produced in the WCSB and 16 per cent of North American natural gas production. Within Alberta, the company delivered approximately 1.6 Bcf/d. The Alberta System connects to the Canadian Mainline, the BC System, the Foothills System and other pipelines which collectively deliver natural gas to eastern Canada and export natural gas to the U.S. Pacific Northwest, Midwest and Northeast.

Strategy One of TransCanada's strategies is to sustain, grow and optimize its natural gas transmission business by connecting new WCSB supply, Northern gas and LNG to growing markets. The natural gas demand growth expected over the next several years suggests that there will be ample opportunity to pursue this strategy. In the short to medium term, growth is expected to come from debottlenecking existing systems, increased ownership of partially-owned pipelines, acquisitions of other pipeline systems and connecting new WCSB supply to market. In the long term, TransCanada is laying the groundwork for developing, building and operating new infrastructure to bring Northern gas and LNG to growing markets.

TransCanada's pursuit of a role in bringing Northern gas to market is also driven by the fact that there is excess capacity on the company's main pipelines, the Alberta System and the Canadian Mainline. If pipelines are built to deliver natural gas from Prudhoe Bay and the Mackenzie Delta, and they connect to existing pipeline systems, the economic viability of TransCanada's pipelines will be enhanced thereby benefiting TransCanada's customers and shareholders.

2003 Business Developments In 2003, TransCanada continued to deliver on its strategy of sustaining, growing and optimizing its Gas Transmission business and took several steps forward in working towards the goal of bringing Northern gas and LNG to market.

In August 2003, the company acquired the remaining interests in Foothills Pipe Lines Ltd. and its subsidiaries (Foothills) previously not held by TransCanada. The Foothills System, which extends more than 1,000 kilometres and carries over 30 per cent of Canadian natural gas exports to the U.S., complements TransCanada's current western Canadian facilities. The company also increased its ownership interest in Portland Natural Gas Transmission System Partnership (Portland) in the Northeast U.S. to 61.7 per cent from 33.3 per cent.

The Foothills acquisition has strengthened TransCanada's position in the potential Alaska Highway Pipeline Project. TransCanada, through Foothills, holds certificates for both the Alaskan and Canadian segments of the Alaska Highway Pipeline Project and also holds significant right-of-way assets for the project in both Canada and Alaska.

In June 2003, TransCanada, the Mackenzie Delta gas producers and the Aboriginal Pipeline Group (APG) reached a funding and participation agreement with respect to the Mackenzie Gas Pipeline Project. TransCanada has agreed to finance the APG for its one-third share of project definition costs in exchange for several options, including an ownership interest in the project, certain rights of first refusal and the right to have the Mackenzie Delta gas flow into the Alberta System.

In September 2003, on the LNG front, TransCanada and ConocoPhillips Company (ConocoPhillips) announced the Fairwinds partnership to jointly evaluate a liquefied natural gas regasification facility in Harpswell, Maine. If all approvals are received, construction of this facility could begin in 2006 and be in operation in 2009. TransCanada also continues to pursue other LNG projects.

Challenges While several positive developments occurred in 2003, there are challenges to the company's ability to sustain, grow and optimize the Gas Transmission business. The nature of the Gas Transmission segment's business risks has changed over the past several years. Two major developments in the pipeline sector in Canada have driven these risks: an increase in competition and essentially flat supply of natural gas from the WCSB. TransCanada faces competition at both the supply end and the market end of the company's pipeline systems. On the supply end, other pipelines are accessing an increasingly mature basin. On the market end, there are other pipelines able to deliver natural gas to markets that were historically served by TransCanada.

TransCanada's ability to grow through the acquisition of other pipeline systems is dependent on the availability of quality pipeline assets for sale, the strength of competitor bids and the company's ability to successfully execute its acquisition strategy.

In the long term, TransCanada's ability to play a significant role in delivering Northern gas to market is dependent on gas producers' willingness and ability to commit their resources to these projects. There are several factors impacting the decision to proceed with these projects, including natural gas prices, capital cost of the pipeline, regulatory approvals, and construction, operational and financial risk.

With increased competition and essentially flat WCSB supply, TransCanada expects there will be little organic growth in its Canadian regulated pipelines, prior to connecting Northern gas supplies. Since a key determinant of earnings is the average investment base, the company also expects that in the absence of increases in return on equity and deemed equity thickness, earnings from these assets will decline. However, despite the potential for declining earnings, cash flow generated from these mature assets is expected to remain strong.

Canadian Regulatory Developments While natural gas supply and demand fundamentals support TransCanada's strategy for growing and optimizing the Gas Transmission business, its Canadian regulated pipelines continue to face the challenges of competition, a maturing WCSB and overall low returns. These challenges drive TransCanada's perseverance to earn higher returns and compete in the North American market.

TransCanada's Canadian regulated assets are approximately $14 billion representing 68 per cent of the company's total asset base at December 31, 2003. In the short to medium term, the company's earnings from its wholly-owned regulated pipelines is dependent not on the amount of natural gas that flows through the pipelines but rather on the amount of capital that is invested in the pipelines, the allowed rate of return and the deemed equity thickness. In the long term however, as WCSB production declines and transportation tolls are impacted, shippers are likely to be less willing to contract for natural gas transmission services.

The NEB regulates the Canadian Mainline, the Foothills System, the BC System as well as the Trans Québec & Maritimes System (TQM), in which the company holds a 50 per cent ownership interest. Earnings from these pipelines are based on the average investment base and a rate of return on a deemed common equity ratio that is determined by the regulator. In 2003, the Canadian Mainline average investment base was $8.6 billion and earned the NEB formula of 9.79 per cent on a deemed common equity ratio of 33 per cent. The NEB formula that determines the rate of return is directly linked to the long-term Canada Bond yield. This leads to a direct correlation between earnings on the Canadian Mainline and the level of long-term interest rates in Canada and has resulted in the rate of return declining substantially over the past decade.

The Alberta System is regulated by the Alberta Energy and Utilities Board (EUB). In 2003, revenue for the Alberta System was based on a negotiated settlement with customers on the pipeline. Negotiations with shippers on the Alberta System were significantly influenced by the 2002 NEB decision on the Canadian Mainline's return in 2001 and 2002. As a consequence, the earnings in the Alberta System's revenue requirement were originally anticipated to be $40 million lower than in 2002. However, incentive earnings of approximately $16 million partially offset this decrease, resulting in a $24 million decline in earnings in 2003 from 2002 for the Alberta System. In 2003, the EUB also approved the Alberta System 2003 Tariff Application which introduced two new services and certain modifications to rate design.

Over the past three years, TransCanada has pursued in various regulatory proceedings both the evolution of its regulated business model and fair returns. In 2001, the company filed the Canadian Mainline 2001 and 2002 Fair Return Application with the NEB. In the application, TransCanada requested the NEB to adopt an after-tax weighted average cost of capital approach to determining returns (instead of the NEB formula tied to interest rates) and requested a higher return. In its June 2002 decision on this application, the NEB retained its formula for the return calculation and increased the Canadian Mainline's deemed common equity ratio to 33 per cent from 30 per cent. The NEB denied TransCanada's subsequent application to review and vary the NEB's decision. TransCanada then petitioned the Federal Court of Appeal which granted leave to appeal. The appeal was heard in February 2004 and TransCanada awaits the judgment.

In July 2003, the NEB issued its decision on TransCanada's 2003 Canadian Mainline Tolls and Tariff Application. The NEB approved key components of the application including an increase in the composite depreciation rate, introduction of a new tolling zone, continuation of fuel incentives and an increase in the bid floor price for interruptible service (IT). This decision addressed key issues such as competition in the end markets of the Canadian Mainline, disincentives for shippers to contract for firm service and the long-term supply risks faced by the WCSB. Tolls for 2003 remain interim pending the outcome of the appeal to the Federal Court of Appeal.

In 2003 and early 2004, the EUB held a Generic Cost of Capital (GCOC) proceeding in Alberta. At the conclusion of this proceeding, the EUB will determine the rate of return on equity for 2004 and the capital structure for each utility under its jurisdiction, including the Alberta System. It also expects to adopt a standardized approach to determining rate of return commencing in 2005.

TransCanada filed Phase I of its Alberta System 2004 General Rate Application (GRA) with the EUB in September 2003 and Phase II in November 2003. This is the first GRA filed with the regulator since 1995. Between 1996 and 2003, the tolls and services on the Alberta System were based on negotiated settlements with the pipeline customers, which were approved by the EUB.

POWER

Opportunities Power demand is expected to grow at the rate of two per cent per year in North America. TransCanada's Power segment has significant opportunities for growth which will take place through quality acquisitions, niche development opportunities and through the optimization of the company's power portfolio by focusing on low-risk opportunities in known markets. Given current restrictions on North American power transmission grids, there is also a need to build efficient power plants that are in close proximity to demand areas.

Strategy Power will continue to focus on developing and acquiring low-cost, base load generation or plants with strong contractual underpinnings in markets where the company has or can acquire significant knowledge and experience. TransCanada will also grow the Power business by building plants that take advantage of efficient cogeneration technology and serve niche markets.

TransCanada's power plants are located in several different regulatory jurisdictions and each one has unique rules and regulations. Power markets are regionalized and in-depth knowledge of each market is important to the success of the operation of these assets. TransCanada has grown the Power business significantly in Alberta, eastern Canada and the U.S. Northeast and has developed extensive experience in these markets. TransCanada will continue to capitalize on its market knowledge and deregulation experience to optimize the asset value of its power portfolio through marketing activities in these geographic areas. TransCanada will pursue operational excellence to be the most profitable and reliable provider of power services in the markets the company serves.

2003 Developments In 2003, TransCanada acquired a 31.6 per cent interest in Bruce Power and announced two new cogeneration plants in Canada. The Bruce Power investment provides TransCanada with low-cost, base load power generation in Ontario, one of the largest markets in North America. Output from the new Québec and New Brunswick cogeneration facilities will be sold under long-term contracts to creditworthy counterparties. These plants are examples of TransCanada's ability to develop power generation in new markets and capitalize on the company's expertise in cogeneration technology.

Challenges TransCanada's main challenges in growing its Power business include the availability of quality acquisition opportunities, and the company's ability to capture those opportunities and find niche markets to develop new power plants.

Power generation is primarily a manufacturing business. TransCanada uses various fuel sources such as natural gas, waste heat, wood waste, coal, nuclear and hydro to generate electricity. A key success factor in any manufacturing business is the ability to operate at the lowest cost possible. There are several drivers of costs in the power generation business such as construction, start-up, fuel and operating costs which TransCanada manages through its operational excellence model. TransCanada's ability to optimize its power assets is driven by factors such as contractual profile, plant availability, reliability, fuel mix management and portfolio/dispatch optimization.

The power markets in North America began deregulating in the mid-1990s and the deregulation process continues to evolve in some markets. Evolving markets can lead to short- to medium-term uncertainty around market structure, including how power and fuel contracts are structured. This ultimately impacts earnings volatility. TransCanada has been successful in operating in both deregulated and regulated markets.

TRANSCANADA – OUTLOOK

In 2004, TransCanada will continue to execute its strategy to grow and optimize its Gas Transmission and Power businesses by redeploying its strong discretionary cash flow.

In the Gas Transmission business, the company will pursue growth through the expansion of current systems to bring new supplies to market, acquisitions of existing pipelines, increased ownership in partially-owned pipelines and continued efforts to bring new sources of natural gas (including Northern gas and LNG) to growing markets. In 2004, the outcome of regulatory proceedings could have a significant impact on the earnings of the Alberta System and Canadian Mainline.

In the Power business, TransCanada will focus on markets in which the company currently operates and has extensive market knowledge and deregulation experience. The company will pursue growth of a balanced portfolio of gas-fired and non gas-fired power plants by building, acquiring and investing in competitive facilities. TransCanada will focus on low-cost, base load generation or assets with strong contractual underpinnings and strive to be one of the lowest-cost providers of power services in North America. Power projects undertaken will benefit from and support TransCanada's strong balance sheet. In 2004, plant availability and fluctuating power prices, especially for Bruce Power, could have a significant impact on the earnings of the Power segment.

Financial flexibility is one of the most important requirements for growing the company. 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.

ACQUISITION OF GAS TRANSMISSION NORTHWEST

On February 24, 2004, TransCanada announced an agreement to acquire Gas Transmission Northwest Corporation (GTN) from National Energy & Gas Transmission, Inc. (NEGT) for approximately US$1.7 billion, including US$500 million of assumed debt and subject to typical closing adjustments.

GTN is a natural gas pipeline company that owns and operates two pipeline systems – the Gas Transmission Northwest pipeline system, formerly known as Pacific Gas Transmission, and the North Baja Pipeline system.

The Gas Transmission Northwest pipeline system consists of more than 2,174 kilometres of pipeline extending from a point near Kingsgate, British Columbia, on the B.C.-Idaho border, to a point near Malin, Oregon on the Oregon-California border. The natural gas transported on this pipeline originates primarily from supplies in Canada for customers located in the Pacific Northwest, Nevada and California.

The North Baja pipeline is a 128 kilometre system. It extends from a point near Ehrenberg, Arizona to a point near Ogilby, California on the California–Baja California, Mexico border. The natural gas transported on this system comes primarily from supplies in the southwestern U.S. for markets in Northern Baja California, Mexico. The sale of the North Baja pipeline is subject to a right of first refusal by another company.

NEGT voluntarily filed for protection under Chapter 11 of the U.S. Bankruptcy Code in July 2003. As a result, the sale of GTN to TransCanada will be subject to bankruptcy court approval, and will include a court-sanctioned auction process in accordance with customary bidding procedures approved by the bankruptcy court. Under a court-sanctioned auction, NEGT will seek offers that are higher or otherwise better than that which has been negotiated with TransCanada. As part of its agreement, TransCanada is granted certain protections, subject to court approval, most notably a break fee and expense reimbursement if another bid is accepted. TransCanada also retains the right to amend its offer should NEGT receive an offer which is superior to its existing agreement with TransCanada. The agreement contemplates that final bankruptcy court approval of the sale will be obtained within 75 days after signing of the agreement. The agreement also contemplates bankruptcy court approval of the NEGT Plan of Reorganization. Approval of NEGT's Plan could occur at a date later than the receipt of court approval of the sale. The sale is also subject to anti-trust review.

TransCanada will finance the acquisition in a manner consistent with maintaining its solid financial position and credit ratings. This could include use of internally generated cash flow, draws on committed credit lines, issuance of debt and/or equity under the Canadian and U.S. shelf prospectuses, and/or the sale of certain assets within the company's existing portfolio.

TransCanada's strategy is to sustain, grow and optimize its natural gas transmission business. The growth in natural gas demand expected over the next several years suggests that there will be ample opportunities to do so.

GAS TRANSMISSION

HIGHLIGHTS

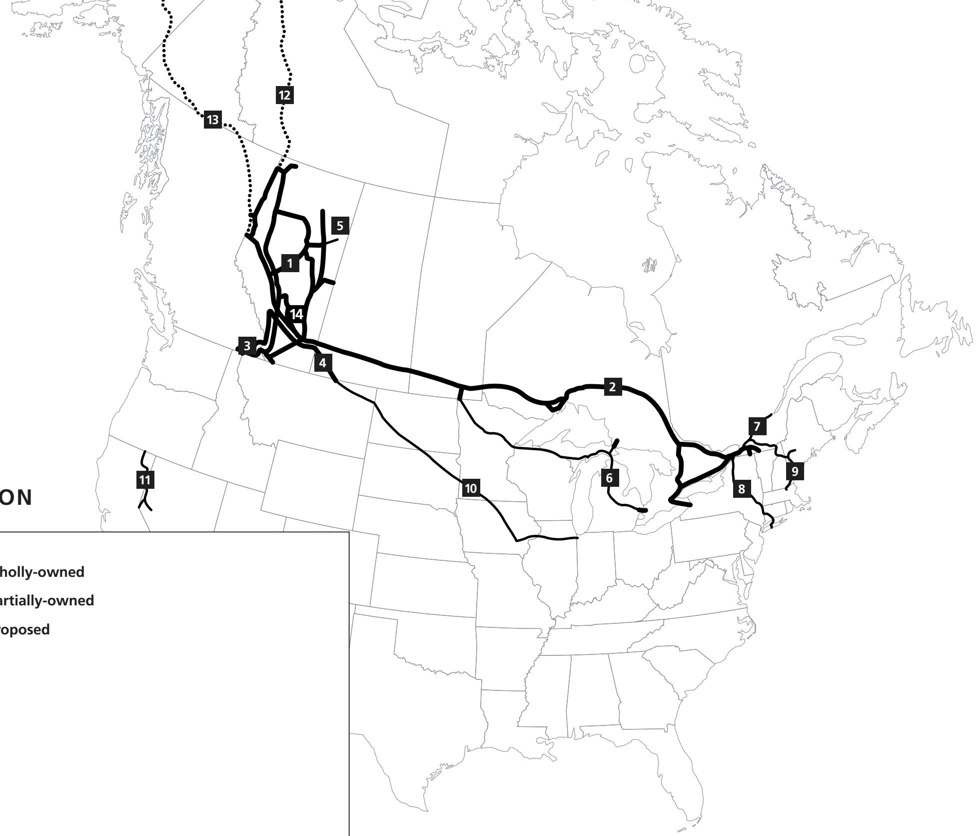
Earnings Net earnings from Gas Transmission decreased $31 million to $622 million in 2003 compared to $653 million in 2002. This decrease is a result of reduced earnings of $38 million from Wholly-Owned Pipelines partially offset by increased earnings of $7 million from Other Gas Transmission.

Alberta System In February 2003, a one-year Alberta System Revenue Requirement Settlement (the 2003 Settlement) was reached for 2003 with Alberta System customers. Earnings in 2003 were initially expected to decrease by approximately $40 million relative to 2002 earnings of $214 million. However, incentive earnings realized primarily from lower financing and operating costs partially offset the expected reduction in earnings.

Canadian Mainline In July 2003, the NEB issued its decision on TransCanada's 2003 Canadian Mainline Tolls and Tariff Application. In its decision, the NEB approved all of the key components of the application including an increase in the composite depreciation rate to 3.42 per cent from 2.89 per cent, introduction of a new tolling zone in southwestern Ontario, an increase to the IT bid floor price and the continuation of the Fuel Gas Incentive Program. Earnings in 2003 reflect, along with incentive earnings from approved programs, return on equity based on the NEB formula and 33 per cent deemed common equity.

Foothills System In August 2003, TransCanada acquired the remaining interests in Foothills previously not held by the company. This acquisition has strengthened TransCanada's position in the potential Alaska Highway Pipeline Project and increased the likelihood that such a project would connect with TransCanada's existing infrastructure.

Other Gas Transmission In 2003, TransCanada increased its ownership interest in Portland to 61.7 per cent from 33.3 per cent through two separate transactions. This increase in ownership, in conjunction with the impact of Portland's 2003 rate settlement, resulted in increased net earnings to TransCanada. TransCanada's investment in TransGas also generated higher net earnings in 2003. Net earnings from Other Gas Transmission in 2003 were negatively impacted by U.S. dollar currency movements, as the majority of earnings in this business are denominated in U.S. dollars. Iroquois Gas Transmission System (Iroquois) placed its Eastchester expansion facilities into service in February 2004.



NATURAL GAS TRANSMISSION

- **1** Alberta System
- **2** Canadian Mainline
- **3** BC System
- **4** Foothills System
- **5** Ventures LP
- **6** Great Lakes
- **7** TQM
- **8** Iroquois
- **9** Portland
- **10** Northern Border
- **11** Tuscarora
- **12** Mackenzie Gas Pipeline Project (proposed by producers)
- **13** Alaska Highway Pipeline (proposed by Foothills Pipe Lines)
- **14** CrossAlta

wholly-owned
partially-owned
proposed

Alberta System TransCanada's 100 per cent owned natural gas transmission system in Alberta gathers natural gas for use within the province and delivers it to provincial boundary points for connection with the Canadian Mainline, BC System, Foothills System and other pipelines. The 22,700 kilometre system is one of the largest carriers of natural gas in North America.

Canadian Mainline TransCanada's 100 per cent owned natural gas transmission system in Canada extends 14,900 kilometres from the Alberta/Saskatchewan border east to Québec/Vermont and connects with other natural gas pipelines in Canada and the U.S.

BC System TransCanada's 100 per cent owned natural gas transmission system extends 200 kilometres from Alberta's western border through B.C. to the U.S. border, serving markets in B.C. as well as the Pacific Northwest, California and Nevada.

Foothills System TransCanada's 100 per cent owned 1,040 kilometre 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.

Ventures LP Ventures LP, 100 per cent owned by TransCanada, owns a 121 kilometre pipeline and related facilities which supply natural gas to the oil sands region of northern Alberta, and a 27 kilometre 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 kilometre pipeline system.

TQM TQM is a 572 kilometre 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.

Transmission Results-at-a-Glance

Year ended December 31 (millions of dollars)	**2003**	2002	2001
Wholly-Owned Pipelines			
Alberta System	**190**	214	204
Canadian Mainline	**290**	307	274
Foothills System (1)	**20**	17	20
BC System	**6**	6	5
	506	544	503
Other Gas Transmission			
Great Lakes	**52**	66	56
Iroquois	**18**	18	16
TC PipeLines, LP	**15**	17	15
Portland (2)	**11**	2	(1)
Ventures LP	**10**	7	3
TQM	**8**	8	8
CrossAlta	**6**	13	8
TransGas	**22**	6	–
Northern Development	**(4)**	(6)	(9)
General, administrative, support and other	**(22)**	(22)	(14)
	116	109	82
Net earnings	**622**	653	585

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

(2) 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 earnings from Portland including a 33.3 per cent ownership interest from June 2001 to September 2003, and a 21.4 per cent ownership interest prior to June 2001.

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 kilometre pipeline system.

Portland Portland operates a 471 kilometre pipeline that connects with TQM near East Hereford, Québec and delivers natural gas to customers in the northeastern U.S. As at December 31, 2003, TransCanada had a 61.7 per cent ownership interest in Portland.

Northern Border Northern Border is a 2,010 kilometre 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 kilometre pipeline system transporting natural gas from Malin, Oregon to Wadsworth, Nevada with delivery points in northeastern California. 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 Gas Storage & Services Ltd. (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 billion cubic feet (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.

TransGas TransGas is a 344 kilometre 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 interest in this pipeline.

In 2003, net earnings from the Gas Transmission business were $622 million, compared to $653 million and $585 million in 2002 and 2001, respectively. The decrease in 2003 compared to 2002 was mainly due to lower net earnings from Wholly-Owned Pipelines, partially offset by higher net earnings from Other Gas Transmission. The 2003 decrease in Wholly-Owned Pipelines' net earnings was primarily due to a reduction in the Alberta System's net earnings reflecting the 2003 Settlement. Further, earnings on the Canadian Mainline were lower in 2003 compared to 2002 due to recognition in June 2002 of the 2001 earnings impact resulting from the Fair Return decision. Higher 2003 net earnings from Other Gas Transmission were primarily due to increased earnings from TransGas and Portland. The increase in 2002 earnings over 2001 was mainly due to the Fair Return decision, higher incentive earnings from Wholly-Owned Pipelines and higher earnings from TransCanada's investment in Great Lakes.

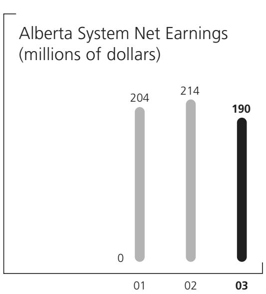
WHOLLY-OWNED PIPELINES – FINANCIAL REVIEW

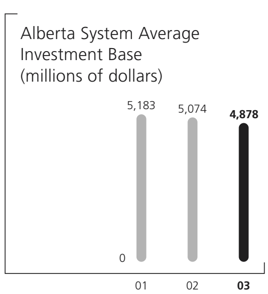
Alberta System Net earnings of $190 million in 2003 were $24 million lower than 2002 and $14 million lower than 2001. The decrease compared to 2002 and 2001 was primarily due to lower earnings resulting from the 2003 Settlement reached between TransCanada and its customers in February 2003. The 2003 Settlement included a fixed revenue requirement component, before non-routine adjustments, of $1.277 billion compared to $1.347 billion in 2002 and $1.390 billion in 2001. The company initially expected the lower negotiated 2003 revenue requirement would reduce 2003 earnings by approximately $40 million relative to 2002. However, higher incentive earnings were realized in 2003, primarily from lower financing and operating costs which partially offset the expected reduction.

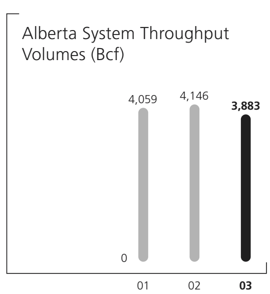
The Alberta System is one of the largest volume carriers of natural gas in North America and delivered 3,883 Bcf of natural gas in 2003, compared to deliveries of 4,146 Bcf in 2002 and 4,059 Bcf in 2001. The volumes transported by the Alberta System in 2003 represented approximately 16 per cent of total North American natural gas production and 66 per cent of the natural gas produced in the WCSB.

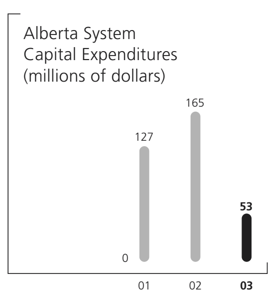
The Alberta System is regulated by the EUB primarily under the provisions of the Gas Utilities Act (Alberta) (GUA) and the Pipeline Act (Alberta). Under the GUA, the rates, tolls and other charges, and terms and conditions of service are subject to approval by the EUB.

Canadian Mainline The Canadian Mainline generated net earnings of $290 million in 2003, a decrease of $17 million compared to 2002 and an increase of $16 million over 2001 earnings. The decrease in net earnings in 2003 from 2002 and the increase in net earnings from 2001 to 2002 was primarily due to recognition of incremental earnings for 2001 and 2002 as a result of the NEB's Fair Return decision in June 2002. This decision included an increase in the deemed common equity ratio to 33 per cent from 30 per cent, effective January 1, 2001, and resulted in additional net earnings of $16 million for the year ended December 31, 2001, that the company recognized in June 2002. Net earnings in 2003 also reflect the continued decrease in average investment base. These factors were partially offset by an increase in the NEB-approved rate of return on common equity to 9.79 per cent in 2003 from 9.53 per cent in 2002. The increase in 2003 earnings relative to 2001 is primarily due to the NEB's Fair Return decision which provided for an increase in deemed common equity to 33 per cent.









Annual deliveries of natural gas on the Canadian Mainline totalled 2,628 Bcf in 2003, compared to 2,630 Bcf in 2002 and 2,450 Bcf in 2001. In 2003, deliveries to export border points comprised 51 per cent of total deliveries compared to 53 per cent in 2002 and 50 per cent in 2001.

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 also provide a return on the Canadian Mainline average investment base. New facilities are approved by the NEB before construction begins. Changes in investment base, the rate of return on common equity, the level of deemed common equity and the potential for incentive earnings affect the net earnings of the Canadian Mainline.

WHOLLY-OWNED PIPELINES – DEVELOPMENTS

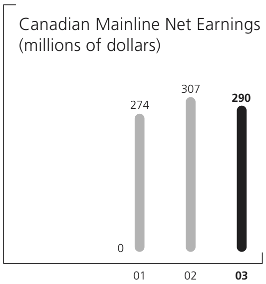
Regulatory In 2003, TransCanada focused much of its efforts on the evolution of its regulated business model. This evolution includes proposed changes to TransCanada's Canadian regulated pipeline business that would provide the company an opportunity to earn a competitive return and enhance its ability to compete for future market demand and natural gas supply while bringing benefits to customers. This regulated business model is intended to advance TransCanada's rate and service offerings on all four of the company's wholly-owned pipelines.

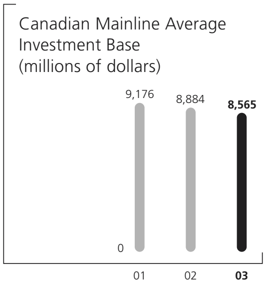
In 2003, TransCanada's activities included its appeal of the NEB's Fair Return Review and Variance decision, the EUB's GCOC Proceeding, preparation of the 2004 Mainline Tolls and Tariff Application, the Alberta System's 2004 GRA, the Alberta System 2003 Tariff Application which was approved by the EUB and continued discussion with industry stakeholders.

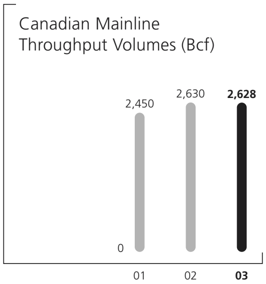
In February 2003, the NEB denied the request TransCanada made in September 2002 for a Review and Variance of the Fair Return decision. TransCanada maintains that the Fair Return decision issued in June 2002 does not recognize the long-term business risks of the Canadian Mainline. The company ultimately initiated an appeal of the NEB's decision not to review and vary the Fair Return decision, with the Federal Court of Appeal. In May 2003, the Federal Court of Appeal granted TransCanada leave to appeal the NEB's February 2003 decision. The appeal was heard in February 2004 and TransCanada awaits the judgment.

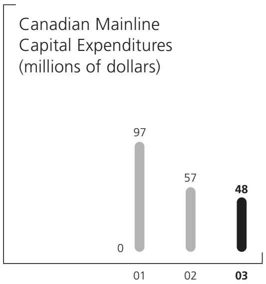
The NEB hearing for TransCanada's 2003 Canadian Mainline Tolls and Tariff Application began in February 2003. In its July 2003 decision on the application, the NEB approved all key components of the application including an increase in the composite depreciation rate to 3.42 per cent from 2.89 per cent, the introduction of a new tolling zone in southwestern Ontario, an increase to the IT bid floor price and the continuation of the Fuel Gas Incentive Program. The 2003 tolls resulting from this decision are interim pending the disposition of TransCanada's appeal to the Federal Court of Appeal regarding the NEB's Review and Variance decision.

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. The EUB expects to adopt a standardized approach to determining the rate of return and capital structure for all utilities under its jurisdiction at the conclusion of this proceeding. Oral testimony in the hearing concluded January 16, 2004. Written argument and reply argument are to follow with an EUB decision expected in third quarter 2004.









In September 2003, TransCanada filed with the EUB Phase I of the Alberta System's 2004 GRA, consisting of evidence in support of the applied-for rate base and revenue requirement. The company applied for a composite depreciation rate of 4.13 per cent compared to the current depreciation rate of 4.00 per cent. In November 2003, the company filed Phase II of the application, which primarily deals with rate design and services. EUB hearings to consider the 2004 GRA Phase I and Phase II applications are scheduled to commence, in Calgary, on April 1, 2004 and June 1, 2004, respectively.

The Canadian Mainline 2004 Tolls and Tariff Application was filed with the NEB on January 26, 2004. In this application, TransCanada requested a Fuel Gas Incentive Program, establishment of a new non-renewable firm transportation (FT) service, modifications to the existing short-term FT service and recovery of costs of service including an 11 per cent return on deemed common equity of 40 per cent.

Operational Excellence TransCanada continued its commitment to operational excellence in 2003 by 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 gas supplies and markets.

In 2003, TransCanada exceeded its performance targets of reducing operating and maintenance costs by rationalizing maintenance and streamlining the delivery of services. The company met ongoing goals in the management of greenhouse gases. TransCanada also achieved exceptional plant operating performance, as measured by the number of operational perfect days on both the Alberta System and the Canadian Mainline. Also in 2003, TransCanada improved customer satisfaction with implementation of new systems to consolidate and enhance management of customer transactions. Customer feedback indicates this system improvement was very well received.

In 2004, TransCanada will continue to focus efforts on cost reduction, operational reliability, and environmental and safety performance. The company has established 2004 operating and maintenance budgets with an expectation of further productivity gains, while operating reliability targets have increased and greenhouse gas emissions management programs continue to receive focused attention. Additional effort will be undertaken in 2004 with respect to improving contractor safety performance.

Supply In 2003, TransCanada continued to connect incremental natural gas supply in the WCSB, in Alberta and from B.C. Additional production from the Sierra area of B.C. is expected to commence delivery to Alberta in early 2004.

The timely connection of these volumes has allowed TransCanada's customers to take advantage of premium gas price environments. TransCanada will continue to grow by seeking new opportunities to connect additional gas supplies.

Markets TransCanada continues to pursue growth opportunities within existing and new natural gas markets. In 2003, TransCanada took steps to expand its pipeline system in western Canada through the pending acquisition of the Simmons Pipeline System, via the execution of a long-term transportation service arrangement with TransCanada Pipeline Ventures Limited Partnership (Ventures LP) and through expansion of the Alberta System. These arrangements, upon regulatory approval expected in 2004, will allow TransCanada to increase the company's delivery capacity into the rapidly expanding area of Fort McMurray, Alberta to approximately 700 MMcf/d.

TransCanada also continues to pursue increased deliveries in response to market growth in both Canada and the U.S. While customers have been repositioning their pipeline contracts away from long haul arrangements originating in Alberta to short haul contracts originating at local market hubs, the underlying markets continue to grow.

Foothills Acquisition In August 2003, TransCanada acquired the remaining interests in Foothills previously not held by the company for $259 million, including assumption of $154 million of Foothills' debt. As a result, TransCanada now owns 100 per cent of Foothills. Foothills and its subsidiaries hold the certificates to build the Canadian portion of the Alaska Highway Pipeline Project which would bring Prudhoe Bay natural gas from Alaska to markets in Canada and the U.S. The "prebuild" portion of this project has been operating for more than 20 years, moving Alberta natural gas to U.S. markets in advance of flows from Alaska. Subsidiaries of Foothills and TransCanada also hold certificates to build the Alaskan section of this project.

WHOLLY-OWNED PIPELINES – 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, the Wholly-Owned Pipelines have focused on providing market-responsive products and services, competitive cost-effective structures, and the highest levels of reliability to customers.

In 2004, the Wholly-Owned Pipelines 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 in resolving jurisdictional issues, advancing changes to the regulated business model and addressing fair return challenges.

Looking forward, as the supply/demand balance tightens, producers will continue to explore and develop new fields, as well as unconventional supply such as gas production from coal bed methane reserves. In addition, stakeholder support is expected to grow for proposals to access Northern gas from the Mackenzie Delta and Alaska North Slope. TransCanada will seek to connect these additional natural gas supplies to the Alberta System.

TransCanada's earnings from its Wholly-Owned Pipelines are primarily determined by the average investment base, return on common equity, deemed common equity and opportunity for incentive earnings. In the short to medium term, the company expects modest growth from these mature assets and therefore anticipates continued decline in the average investment base. Accordingly, without an increase to return on equity, 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 Wholly-Owned Pipelines are not affected by short-term fluctuations in the commodity price of natural gas, changes in throughput volumes or changes in FT contract levels.

Earnings In 2004, net earnings from Wholly-Owned Pipelines will depend in large part on the outcome of the appeal of the NEB's Fair Return Review and Variance decision, the EUB's GCOC hearing, the 2004 Mainline Tolls and Tariff Application and the Alberta System's 2004 GRA. In the absence of favorable rulings in these applications, the company expects 2004 earnings to be lower compared to 2003 earnings, primarily due to the combined effect of a decrease in rate of return on common equity in 2004 (Canadian Mainline 2003 – 9.79 per cent versus 2004 – 9.56 per cent based on 0the NEB formula) and lower average investment bases. Although 2004 earnings may be lower than 2003 earnings, Wholly-Owned Pipelines will continue to generate strong cash flow.

Capital Expenditures Total capital spending for the Alberta System, Canadian Mainline and BC System during 2003 was approximately $100 million. Capital spending in 2004, including the Foothills System, is expected to approximately double the expenditures in 2003, primarily due to higher capacity capital spending.

WHOLLY-OWNED PIPELINES – BUSINESS RISKS

Competition TransCanada faces competition at both the supply end and the market end of its systems. The competition is a result of other pipelines accessing an increasingly mature WCSB. The construction of the Alliance Pipeline, a natural gas pipeline from northeast B.C. to the Chicago area, and the continued expiration of transportation contracts have resulted in significant reductions in firm contracted capacity on both the Alberta System and the Canadian Mainline. The Canadian Mainline absorbs the bulk of any volume swings in the WCSB.

As of December 2002, the WCSB had estimated remaining discovered natural gas reserves of 57 trillion cubic feet and a reserves-to-production ratio of approximately nine years at current levels of production. Additional reserves are continually being discovered to maintain the reserves-to-production ratio at close to nine years. Natural gas prices in the future are expected to be higher than long-term historical averages due to a tighter supply/demand balance which should stimulate exploration and production in the WCSB. However, the WCSB supply is expected to remain essentially flat.

TransCanada's Alberta System provides the major natural gas gathering and export transportation capacity for the WCSB. It does so by connecting to most of the 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. 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. TransCanada continues to face competition for transportation services to eastern Canadian markets and U.S. export points. 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 have historically received Canadian supplies only from TransCanada are capable of receiving supplies from new pipelines into the region that can source both western Canadian and U.S. supplies.

The Canadian Mainline has experienced reductions in long haul FT contracts for deliveries originating at the Alberta border and in Saskatchewan of approximately 2.5 Bcf/d, or approximately 36 per cent of its capacity since the 1998/1999 contract year. 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 utilization of the Canadian Mainline is not expected to increase in the short to medium term as any additional supply from the WCSB is expected to be absorbed by demand growth within western Canada and by higher flows on other pipeline systems.

TransCanada will continue to work with stakeholders in 2004 to advance various aspects of the company's regulated business model for the Alberta System, Canadian Mainline, Foothills System and the BC System.

Financial Risk The company remains concerned about the long-term implications of a financial return that discourages additional investment in existing Canadian natural gas transmission systems. TransCanada has applied for a return of 11 per cent on 40 per cent deemed common equity, both to the NEB in the 2004 Mainline Tolls and Tariff Application and to the EUB in the Alberta System's application in the GCOC Proceeding. The outcome of the Federal Court of Appeal hearing regarding the NEB's Review and Variance decision as well as the GCOC proceeding, could have a significant impact on the financial returns for, and future investment in, TransCanada's Canadian pipelines.

The company is cognizant 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.

Safety TransCanada worked closely with regulators, customers and communities during 2003 to ensure the continued safety of employees and the public. In 2003, two line breaks occurred in a remote area of Alberta resulting in a short-term reduction in natural gas shipments. Neither incident resulted in injuries or damage to public property. Under the current regulatory models, expenditures on pipeline integrity have no negative impact on earnings. The company expects to spend approximately $76 million in 2004 on pipeline integrity compared to $73 million in 2003. 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 2003, TransCanada continued to conduct activities to increase environmental protection through proactive sampling, remediation and monitoring programs. Compressor stations on the Canadian Mainline have been assessed through the company's Site Assessment, Remediation & Monitoring (SARM) program. In 2003, approximately $5 million was invested in improved environmental protection measures at identified TransCanada locations. 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 four Alberta sites was undertaken in 2003, effectively remediating each site.

For information on management of risks with respect to the Gas Transmission business, please see the Risk Management section beginning on page 46 of this Annual Report.

OTHER GAS TRANSMISSION – FINANCIAL REVIEW

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

TransCanada's net earnings from Other Gas Transmission in 2003 were $116 million compared to $109 million and $82 million in 2002 and 2001, respectively. The increased net earnings of $7 million in 2003 compared to 2002 were due to higher earnings from TransGas as a result of recognition of an adjustment for future income tax benefits of $11 million and higher contractual tolls in 2003. In addition, earnings from Portland were higher compared to 2002 due to the impacts of a rate settlement in early 2003 and TransCanada increasing its ownership interest in 2003. Earnings from Ventures LP was also higher due to higher contracted transportation volumes. These increases were partially offset by the impact of a substantially weaker U.S. dollar, higher project development costs and lower earnings from CrossAlta due to lower storage margins as a result of unfavourable market conditions. In addition, 2002 earnings included TransCanada's $7 million share of a favourable ruling for Great Lakes related to Minnesota use tax paid in prior years.

Other Gas Transmission net earnings of $109 million in 2002 increased by $27 million compared to 2001. This increase resulted from higher earnings from U.S. investments which included TransCanada's $7 million share of the favourable ruling for Great Lakes related to Minnesota use tax paid in prior years, increased ownership interests in Iroquois and Portland acquired in mid-2001, higher transportation margins and favourable movements in exchange rates. Earnings from CrossAlta were also higher due to higher storage margins, increased storage capacity and reduced operating expenses. In addition, there was reduced spending on Northern Development in 2002 and increased earnings from Ventures LP.

OTHER GAS TRANSMISSION – DEVELOPMENTS

In 2003, TransCanada increased its ownership interest in Portland, secured a position in the Mackenzie Gas Pipeline Project and pursued LNG projects by conducting preliminary assessments of LNG facilities in the Northeast U.S. and eastern Canada.

TC PipeLines, LP TransCanada holds a 33.4 per cent interest in TC PipeLines, LP that in turn holds a 30 per cent interest in Northern Border Pipeline Company (Northern Border) and a 49 per cent interest in Tuscarora Gas Transmission Company (Tuscarora). In July 2003, TC PipeLines, LP increased its quarterly distribution to US$0.55 per unit from US$0.525 per unit. This represents the fourth increase in the partnership's quarterly cash distribution since the commencement of operations in May 1999.

In December 2003, Tuscarora received management approval for an expansion project which will provide for approximately 57 MMcf/d of incremental capacity on its system. Total capital cost is estimated to be approximately US$16.6 million, and the expansion is scheduled to commence service in November 2005.

Iroquois The Eastchester expansion project experienced several delays throughout 2003 primarily due to construction complications. However, by the end of 2003, Iroquois had successfully resolved the majority of these construction issues and placed the expansion facilities into service in February 2004. The expansion is the first major natural gas transmission pipeline to be built into New York City in approximately 40 years.

In October 2003, the Federal Energy Regulatory Commission (FERC) approved Iroquois' mainline rate settlement, which was filed in August 2003. The settlement is effective from January 1, 2004 through

December 2007, during which period Iroquois will reduce rates by approximately 13 per cent. The settlement does not establish rates, terms or conditions for the Eastchester expansion, which was covered by a separate rate application filed with the FERC in January 2004. The FERC has issued an order that accepts Iroquois' application effective July 1, 2004 subject to refund and conditions, and establishing hearing procedures.

Portland In September 2003, the company purchased an additional 10.1 per cent ownership interest in Portland for approximately US$47 million, including assumed debt of approximately US$28 million. In December 2003, the company purchased a further 18.3 per cent interest for approximately US$82 million, including assumed debt of approximately US$50 million, thus increasing its total ownership interest in Portland to 61.7 per cent. Subsequent to this acquisition, Portland was fully consolidated in the company's financial statements, with 38.3 per cent reflected in non-controlling interests.

Portland and customer representatives reached an agreement on new tolls and FERC approved it in its entirety in January 2003. The agreement is effective from April 1, 2002 through April 1, 2008. Lower depreciation rates and revised tolls provided for in the agreement have had a positive impact on Portland's earnings in 2003.

TQM In January 2003, TransCanada began performing the majority of operational and administrative activities for TQM to allow TQM to benefit from best practices employed in the industry at the lowest possible cost. As a result of this reorganization, TQM has realized cost savings, which, in accordance with its incentive agreement, will be shared among its customers and owners.

Northern Development In 2003, TransCanada continued to pursue pipeline opportunities to move both Mackenzie Delta and Alaska North Slope natural gas to markets throughout North America. TransCanada worked with key stakeholders with the objective of participating in any potential pipeline project.

TransCanada, the Mackenzie Delta gas producers and the APG reached funding and participation agreements in June 2003 that enable the APG to become a full participant in the proposed Mackenzie Gas Pipeline Project. This project would result in a natural gas pipeline being constructed from Inuvik, Northwest Territories to the northern border of Alberta, where it would then connect with the Alberta System. TransCanada has agreed to finance the APG for its one-third share of project definition costs. This share is currently expected to be approximately $90 million over three years. This loan will be repaid from the APG's share of future pipeline revenues. In the year ended December 31, 2003, TransCanada funded $34 million of this loan. 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.

TransCanada continued to work with the Alaska Highway Pipeline stakeholders in 2003 to advance that project. Resolution of Foothills' Special Charge was reached with Foothills shippers and the Canadian Association of Petroleum Producers, and subsequently approved by the NEB, in March 2003. The resolution waives Foothills' obligation to repay all past and future Special Charge collections when Alaskan gas starts flowing on the Foothills System. In October 2003, the Government of Canada, once again, reaffirmed its preference to utilize the framework provided in the Northern Pipeline Act which granted Foothills the certificates to transport Alaskan gas across Canada. In January 2004, Foothills and the Kaska First Nation signed an Agreement-in-Principle that provides the framework for a future participation agreement. The Agreement-in-Principle marks the completion of the second stage of negotiations that is expected to lead to a participation agreement for the Alaska Highway Pipeline Project.

Liquefied Natural Gas In September 2003, TransCanada and ConocoPhillips announced the Fairwinds partnership to jointly evaluate a site in Harpswell, Maine for the development of an LNG regasification facility. The residents of the Town of Harpswell are expected to vote on leasing a town-owned site for the facility. If leasing of the site is approved and necessary regulatory approvals are subsequently received, construction of the LNG facility could begin in 2006 with the facility becoming operational in 2009. Natural gas from the LNG facility would be delivered by pipeline to markets in the northeast U.S.

OTHER GAS TRANSMISSION – STRATEGY AND OUTLOOK

TransCanada continues to actively pursue natural gas pipeline and gas transmission related development and acquisition opportunities in North America, where these opportunities are driven by strong customer demand and sound economics. With TransCanada's strong financial position, the company is poised to capitalize on future acquisition and development opportunities. 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 natural gas reserves in the North and Atlantic Canada.

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 competitive advantages including expertise in the design, construction and operation of large diameter pipelines 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.

Excluding the impact of the recognition of the $11 million TransGas future tax benefits in 2003, the net earnings outlook for Other Gas Transmission in 2004 is expected to be similar to 2003. Net earnings will be affected by factors such as the performance of the Canadian dollar relative to the U.S. dollar and the level of project development costs.

OTHER GAS TRANSMISSION – BUSINESS RISKS

Foreign Exchange A significant amount of the earnings in Other Gas Transmission is generated from U.S. pipeline affiliates. The performance of the Canadian dollar relative to the U.S. dollar would either positively or negatively impact this business segment's results.

Throughput Risk Iroquois, Portland and Tuscarora all have long-term demand charge contracts in place with customers and as such, are virtually unaffected by changes in throughput. As transportation contracts expire on Great Lakes and Northern Border, these entities 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.

Insurance, Employee Benefits and Interest Rates Insurance costs continue to rise with the increasing risk of terrorism and sabotage in recent years. The costs of employee benefits, particularly in the U.S., also continue to increase. At the same time, interest rates remain near historical lows. If these insurance and employee benefits costs continue to rise and the economic recovery results in increased interest rates, earnings of Other Gas Transmission could be negatively impacted.

Regulation The U.S. partially-owned pipelines are regulated by the FERC while the Canadian partially-owned pipeline is regulated by the NEB. These regulators play a significant role in approving the pipelines' respective returns on equity, capital structures, tolls and system expansions.

Natural Gas Throughput Volumes

(Bcf)	**2003**	2002	2001
Alberta System (1)	**3,883**	4,146	4,059
Canadian Mainline (2)	**2,628**	2,630	2,450
Foothills System	**1,110**	1,098	1,117
BC System	**325**	371	395
Great Lakes	**856**	863	804
Northern Border	**850**	839	821
Iroquois	**341**	340	314
Portland	**53**	52	44
Tuscarora	**22**	20	23
TQM	**164**	175	161
Ventures LP	**111**	85	60
TransGas	**16**	16	14

(1) Field receipt volumes for the Alberta System for the year ended December 31, 2003 were 3,892 Bcf (2002 – 4,101 Bcf; 2001 – 4,170 Bcf).

(2) Canadian Mainline deliveries originating at the Alberta border and in Saskatchewan for the year ended December 31, 2003 were 2,055 Bcf (2002 – 2,221 Bcf; 2001 – 2,098 Bcf).

TransCanada's strategy is to grow and optimize its Power business by developing and acquiring low-cost, base-load generation or plants that have strong contractual underpinnings. TransCanada will continue to focus on markets where the company has a competitive advantage.

POWER

HIGHLIGHTS

Earnings The Power segment made a significant contribution to TransCanada's earnings in 2003. Net earnings increased 51 per cent from 2002 due in part to the acquisition of Bruce Power and increased earnings from Western Operations.

Bruce Power TransCanada completed the acquisition of a 31.6 per cent equity interest in Bruce Power, the operator and lessee of the Bruce nuclear power facility in Ontario. This acquisition indirectly increased TransCanada's nominal generating capacity by 1,000 MW in February 2003. The return to service of Bruce Power A Unit 4 in fourth quarter 2003 and Bruce Power A Unit 3 in first quarter 2004 increased TransCanada's 31.6 per cent share of the nominal generating capacity of Bruce Power to 1,474 MW.

Expanding Asset Base In June 2003, TransCanada announced its plans to develop the 550 MW Bécancour natural gas-fired cogeneration power plant in Québec. The project which is estimated to cost approximately $550 million, including capitalized interest, is expected to be placed in-service in late 2006. In October 2003, TransCanada and Grandview Cogeneration Corporation, an affiliate of Irving Oil Limited (Irving), announced an agreement to construct a 90 MW natural gas-fired cogeneration power plant on the site of the Irving Oil Refinery in Saint John, New Brunswick. The plant is expected to be placed in-service by the end of 2004 at a total estimated cost of approximately $90 million. The company placed the Bear Creek plant in Alberta in-service in first quarter 2003 and expects the MacKay River plant to be commercially in-service in first quarter 2004.

Operational Excellence Average plant availability, excluding Bruce Power, was 94 per cent in 2003 compared to 96 per cent in 2002. This slight decrease resulted primarily from scheduled maintenance at some of the plants in Western Operations. Including Bruce Power, average plant availability decreased to 90 per cent for 2003 as a result of scheduled maintenance on two Bruce Power B units.

POWER GENERATION

1. Bear Creek
2. MacKay River
3. Redwater
4. Sundance A PPA
5. Sundance B PPA (50%)
6. Carseland
7. Cancarb
8. ManChief
9. Bruce Power (31.6%)
10. Curtis Palmer
11. Ocean State
12. Bécancour (in permitting phase)
13. Grandview (under construction)

TransCanada Power, L.P.
(35.6%)

14. Williams Lake
15. Nipigon
16. Calstock
17. Kapuskasing
18. Tunis
19. North Bay
20. Castleton

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 facility near Fort McMurray, Alberta was completed in fourth quarter 2003.

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 plant in Alberta is the largest coal-fired electrical generating facility in western Canada. Through the Alberta PPA auction in August 2000, TransCanada acquired the Sundance A PPA, which increased the company's power supply by 560 MW for a 17 year period commencing January 2001. In December 2001, TransCanada acquired 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 January 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.

ManChief In November 2002, TransCanada acquired the 300 MW simple-cycle ManChief facility near Brush, Colorado. The entire capacity of the natural gas-fired ManChief plant is sold under long-term tolling contracts that expire in 2012.

Bruce Power In February 2003, TransCanada acquired a 31.6 per cent equity interest in Bruce Power, the operator and lessee of the Bruce nuclear power facility located near Lake Huron, Ontario. This investment indirectly increased TransCanada's nominal generating capacity by 1,000 MW, with an additional 474 MW restarted in late 2003 and early 2004.

Power Results-at-a-Glance

Year ended December 31 (millions of dollars)	**2003**	2002	2001
Western operations	**160**	131	149
Eastern operations	**127**	149	159
Bruce Power investment	**99**	–	–
Power LP investment	**35**	36	39
General, administrative and support costs	**(86)**	(73)	(49)
Operating and other income	**335**	243	298
Financial charges	**(12)**	(13)	(24)
Income taxes	**(103)**	(84)	(106)
Net earnings	**220**	146	168

Curtis Palmer The 60 MW Curtis Palmer facility near Corinth, New York is the company's only hydroelectric facility. All output from this facility is sold through a fixed-priced, long-term agreement.

Ocean State The Ocean State Power (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 in the permitting phase and is expected to be in-service in late 2006. The entire output will be supplied to Hydro-Québec Distribution under a 20 year power purchase contract. Steam will also be supplied to businesses located nearby.

Grandview The 90 MW Grandview natural gas-fired cogeneration power plant located in Saint John, New Brunswick is under construction and is expected to be in-service in late 2004. Under a 20 year tolling arrangement, 100 per cent of the plant's heat and electricity output will be sold to Irving.

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

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.

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.

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

Nominal Generating Capacity and Fuel Type of Power Plants

	MW	Fuel Type
Western operations		
Sundance A (1)	560	Coal
Sundance B (1)	353	Coal
ManChief	300	Natural gas
MacKay River	165	Natural gas
Carseland	80	Natural gas
Bear Creek	80	Natural gas
Redwater	40	Natural gas
Cancarb	27	Natural gas
	1,605	
Eastern operations		
Ocean State	560	Natural gas
Curtis Palmer	60	Hydro
Bécancour (2)	550	Natural gas
Grandview (3)	90	Natural gas
	1,260	
Bruce Power investment (4)		
Bruce B (5)	1,000	Nuclear
Bruce A (6)	474	Nuclear
	1,474	
Power LP investment (7)		
Williams Lake	66	Wood waste
Castleton	64	Natural gas
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
	328	
	4,667	

(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 in the permitting phase.

(3) Currently under construction.

(4) Represents TransCanada's 31.6 per cent equity interest in Bruce Power.

(5) Bruce B consists of four reactors, which are currently in operation, with a capacity of approximately 3,160 MW. The generating capacity of approximately 1,000 MW includes two MW from TransCanada's 17 per cent indirect share in Huron Wind L.P. which owns a nine MW wind farm.

(6) Bruce A consists of four 750 MW reactors. Bruce A Unit 4 was returned to service in the fourth quarter of 2003. Bruce A Unit 3 was returned to service in first quarter 2004. Bruce A Units 1 and 2 remain out of service.

(7) At December 31, 2003, TransCanada operated and managed Power LP and held a 35.6 per cent ownership interest in Power LP. The volumes in the table represent 100 per cent of plant capacity.

TransCanada's Power business contributed $220 million of net earnings in 2003, an increase of $74 million or 51 per cent compared to earnings of $146 million in 2002. This increase is primarily attributable to TransCanada's acquisition in February 2003 of a 31.6 per cent interest in Bruce Power and higher contributions from Western Operations. Partially offsetting the increase were lower earnings from Eastern Operations and higher general, administrative and support costs.

The increase in general, administrative and support costs in 2003 compared to the two prior years reflects higher support costs associated with the company's focus on growth in Power.

Power's net earnings of $146 million in 2002 decreased $22 million compared to 2001. This decrease primarily reflected TransCanada's ability to capitalize on market opportunities in both Western and Eastern Operations in 2001 which did not exist in 2002.

POWER – DEVELOPMENTS

TransCanada's Power segment had another strong year in 2003. The Power segment continued to grow, completing the acquisition of a 31.6 per cent interest in Bruce Power in February 2003, placing the Bear Creek plant in-service in 2003, and completing construction of the MacKay River facility at the end of 2003. TransCanada also increased its presence in eastern Canada, announcing plans to construct two power plants, Bécancour in Québec and Grandview in New Brunswick.

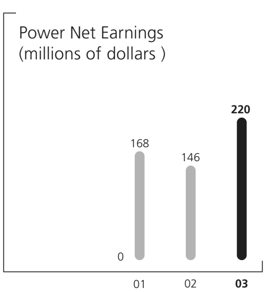
TransCanada continues to utilize its competitive strengths to seek quality acquisitions, greenfield development opportunities and expansion of the company's existing businesses to complement the current portfolio of power generation assets. TransCanada is generally able to expand the company's portfolio of power plants while mitigating excessive price risk through the long-term sale of electricity and steam/heat to the adjacent industrial customers for a portion of the plant output while, at the same time, retaining a certain amount of merchant power capacity to be sold to other customers.

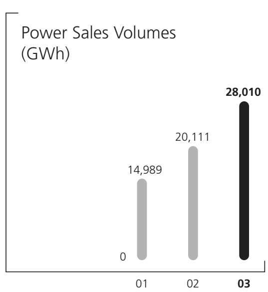
WESTERN OPERATIONS

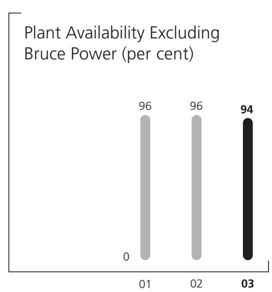
The focus of Western Operations is to optimize and expand the existing asset base and maximize asset value through a combination of long- and short-term sales contracts and low-cost generation and supply.

Western Operations has two main components – Western Marketing and Plant Operations. Western Marketing consists of the power marketing operations originating out of the Calgary office, including marketing of uncommitted generation from the Alberta plants and the purchase and resale of electricity related to the Sundance PPAs. Western Marketing also participates in marketing electricity in western Canada and throughout the U.S. from Washington state to Wisconsin. Plant Operations consists of contributions from the Alberta power plants, the ManChief plant in Colorado, and fees earned to manage and operate Power LP's seven plants.

Western Marketing While a significant portion of Western Plant Operations' generation is sold under long-term contracts to mitigate price risk, some power is intentionally not sold under long-term contracts. The Western Marketing group's primary function is to manage these open positions to maximize the value of Power's assets through marketing and trading activities as well as through operational optimization. In order to mitigate market price risk, Western







Operations has sold approximately 84 per cent of the total generation for 2004 and 70 per cent of the expected, average combined total power supply for the next three years. Western Operations' largest power supply is its Sundance PPAs. TransCanada has sold essentially all of the Sundance PPA power supply in 2004 and 69 per cent and 49 per cent of the expected combined power supply for 2005 and 2006, respectively. Western Marketing continues to secure additional long-term sales contracts for the remaining power supply.

Plant Operations Plant Operations is another area of success and growth for TransCanada. The expansion of this area is consistent with TransCanada's focus on capitalizing on the company's expertise in developing new projects and maintaining its position as a prominent player in the Alberta market. The Bear Creek plant began commercial operations in March 2003. This 80 MW cogeneration facility near Grande Prairie, Alberta sells the majority of its power to Weyerhaeuser's Grande Prairie Pulp Mill, as well as Weyerhaeuser's other Alberta facilities.

Construction of the MacKay River plant was completed in fourth quarter 2003 and the plant is expected to be in-service in first quarter 2004. The 165 MW cogeneration facility near Fort McMurray, Alberta, will provide electricity and steam to Petro-Canada's adjacent in-situ oil sands operations. The MacKay River plant increases TransCanada's directly controlled supply in Alberta to more than 1,300 MW.

Plant Operations is committed to an operational excellence model that provides low-cost, reliable operating performance at each of its plants. The Redwater and Carseland plants, both completing their second year of operation, operated very well in 2003. Bear Creek is still in its first year of operations and is in the process of ongoing operational optimization. ManChief, which was acquired in November 2002, is another solid performing asset in TransCanada's power generation portfolio. The entire capacity is sold under long-term tolling contracts that expire in 2012.

Operating and other income from Western Operations increased by 22 per cent to $160 million in 2003 from $131 million in 2002 due primarily 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. 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 carbon black facility.

While the average Alberta Pool Price for 2003 was $63/megawatt hour (MWh) compared to $44/MWh in 2002, margins were lower in 2003 due to lower realized prices and reduced market liquidity.

Operating income from Western Operations decreased $18 million to $131 million in 2002 when compared to 2001. Market opportunities that existed in 2001 resulting from high power prices (average Alberta Pool Price of $71/MWh in 2001) and price volatility in western Canada and the Pacific Northwest regions did not carry over into 2002. However, this was partially offset by income from the acquisition of the Sundance B PPA, ManChief, and the placing in-service of the Redwater and Carseland plants.

EASTERN OPERATIONS

Power's Eastern Operations is focused on the New England and New York deregulated power markets and consists of Power Marketing and Power Generation operations, both of which operate as one integrated business. Eastern Operations also include the company's development opportunities in Ontario and other provinces in eastern Canada.

Over the past five years, TransCanada Power Marketing Limited (TCPM), an affiliate located in Westborough, Massachusetts, has successfully navigated through New England's deregulation process and firmly established itself as a leading power generator and energy provider in the New England power market. TransCanada continues to seek out opportunities to add generation capacity to the existing asset base and leverage off this experience in expanding its presence in the Ontario market.

Power Marketing TransCanada's continued success and growth in the northeast U.S. is the direct result of an efficient 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 both its own generation assets and wholesale power purchases. TCPM is a full service provider offering different products and services to assist customers in managing their power supply and power prices in deregulated power markets. Through active portfolio management, TCPM has positioned itself to capture market opportunities as they arise, while reducing downside exposure. Included in the additional power supply is TCPM's purchase of 100 per cent of the output of the 64 MW natural gas-fired combined-cycle plant located in Castleton-on-Hudson, New York (Castleton), which is owned by Power LP.

Power Generation Eastern U.S. power generation assets include OSP, a 560 MW natural gas-fired plant located in Rhode Island, and the 60 MW Curtis and Palmer hydroelectric facilities (Curtis Palmer) near Corinth, New York. Of the total OSP output, 76.5 per cent is sold under long-term purchase arrangements to TCPM with the remainder sold to Boston Edison Company. Output from Curtis Palmer is sold into the New York market under a fixed-price, long-term power purchase agreement with Niagara Mohawk Power Corporation for an expected term of more than 25 years. Curtis Palmer has a high capacity factor due to its strategic location just downstream of certain water storage facilities on the Hudson River, but earnings are subject to seasonal and annual variations in water levels.

Operating 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 in the eastern U.S. retail business which is focused on sales to large 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 built and operated in Cobourg, Ontario during the summer of 2003.

Operating income of $149 million in 2002 was slightly lower than the unprecedented $159 million of earnings in 2001. The decrease year over year was primarily due to the ability throughout 2001 to capitalize on price volatility that was less prevalent in 2002, partially offset by a full year of earnings from the Curtis Palmer hydroelectric facilities purchased in July 2001.

The long-term natural gas supply for OSP is subject to a yearly price renegotiation. If OSP and the suppliers are unable to reach an agreement on price in a given year, the matter is settled by arbitration. OSP is currently in its third such arbitration with its natural gas fuel suppliers. The first two arbitration decisions substantially increased OSP's natural gas fuel costs.

Development Opportunities in Eastern Canada

In October 2003, TransCanada and an affiliate of Irving announced an agreement to build a 90 MW natural gas-fired cogeneration power plant in Saint John, New Brunswick to be developed and owned by TransCanada. 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. Construction of the facility began in December 2003 and is expected to be in-service by the end of 2004.

In June 2003, TransCanada announced its plans to develop a 550 MW natural gas-fired cogeneration power plant in Québec. The power plant will be located in the Bécancour Industrial Park, near Trois-Rivières and will supply its entire power output to Hydro-Québec Distribution under a 20 year power purchase contract. The plant will also supply steam to certain major businesses located within the industrial park. Construction of the facility is likely to begin in 2004, pending receipt of regulatory approvals, and is expected to be in-service in late 2006.

Power continues to assess the viability of developing a natural gas-fuelled energy centre to meet electricity needs in downtown Toronto through its partnership with Ontario Power Generation (OPG) in the Portlands Energy Centre L.P. Situating generation in downtown Toronto, close to the end user, would help alleviate current and future transmission issues in the downtown core.

BRUCE POWER INVESTMENT

On February 14, 2003, the company completed the acquisitions of a 31.6 per cent interest in Bruce Power and a 33.3 per cent interest in Bruce Power Inc., the general partner of Bruce Power, for $409 million. TransCanada also funded a one-third share ($75 million) of a $225 million accelerated deferred rent payment made by Bruce Power to 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 made up of two nuclear plants – Bruce B and Bruce A. Bruce B consists of four reactors, which are currently in operation, with a capacity of approximately 3,160 MW. Bruce A consists of four reactors, which up until 2003, were not operating. In 2003, Bruce Power completed efforts to restart Bruce A Unit 4, followed on January 8, 2004 with the restart of Bruce A Unit 3. Both units were laid-up in 1998. These two Bruce A units add 1,500 MW of capacity, bringing Bruce Power's total capacity to 4,660 MW.

Bruce Power is the tenant under a lease with OPG on the Bruce nuclear power facility. The initial term of the lease expires in 2018 with an option to extend the lease by up to 25 years. The Bruce nuclear power facility continues to be managed and operated by the management and staff of Bruce Power. Spent fuel and decommissioning liabilities remain the responsibility of OPG and, as determined at the inception of the lease, are covered by the existing lease payments. The lease agreement with OPG provides for limited adjustments to the base rent every five years during the initial term of the lease. These limited adjustments are based on a maximum of 50 per cent of the discounted value of the expected increase to the decommissioning costs for the Bruce nuclear power facility, determined using predetermined principles and assumptions. There are no similar adjustments to the existing lease payments with respect to spent fuel liabilities. Commencing in 2006, Bruce Power also has the right to terminate the lease if the continuing operation of the facility is no longer economically viable, subject to a lease termination fee, certain ongoing operational requirements during handover and certain shut-down conditions prior to handover. TransCanada has severally guaranteed Bruce Power's performance of these obligations.

TransCanada's share of power output during the period of ownership in 2003 was 6,655 gigawatt hours (GWh). This includes power output from Bruce A Unit 4 for November and December 2003. Bruce A Unit 4 began producing electricity to the Ontario electricity grid on October 7, 2003 and was considered commercially in-service on November 1, 2003. Bruce A Unit 3 reconnected to the Ontario electricity grid on January 8, 2004. Similar to the Bruce A Unit 4 startup process, after performing and evaluating tests of the shutdown system, Bruce A Unit 3 was reconnected to the grid and is expected to ramp up to full power in first quarter 2004. As of December 31, 2003, Bruce Power's cumulative restart costs for the two Bruce A units were approximately $720 million. Bruce Power incurred approximately $300 million on the two unit restart program for the period February 14, 2003 to December 31, 2003. TransCanada did not provide any funding to Bruce Power subsequent to the acquisition of the company's ownership interest in February 2003.

Bruce Power spent approximately $147 million on capital expenditures at Bruce B for the period February 14, 2003 to December 31, 2003, the majority of which was for safety systems and power uprate programs.

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 1,560 MW of output for 2004. The average availability in 2004 for the six Bruce units is expected to be approximately 80 per cent compared to 85 per cent for the year ended December 31, 2003. This decrease reflects planned maintenance outages and a test of the Bruce B vacuum building expected in the fall, which will require all four Bruce B units to be taken offline for approximately one month. Capital expenditures by Bruce Power in 2004 are expected to total about $400 million, including approximately $120 million for sustaining capital. TransCanada does not expect to provide any funding to Bruce Power in 2004.

Bruce Power contributed $99 million of pre-tax equity income in 2003. TransCanada's interest in Bruce Power's pre-tax income for 2003 was $65 million. The additional $34 million of income consisted primarily of the amortization of purchase price allocations as explained in Note 6 to the December 31, 2003 Consolidated Financial Statements as well as $12 million of capitalized interest. Bruce Power's average realized price in 2003 from a combination of contract and spot sales was approximately $48/MWh. Approximately 65 per cent of Bruce Power's output was sold under longer term contracts in 2003 with the remainder being sold into Ontario's wholesale spot market.

Bruce Power Results-at-a-Glance

Year ended December 31 (millions of dollars)	2003
Bruce Power (100 per cent basis)	
Revenues	**1,208**
Operating expenses	**(853)**
Operating income	**355**
Financial charges	**(69)**
Income before income taxes	**286**
TransCanada's interest in Bruce Power income before income taxes (1)	**65**
Adjustments (2)	**34**
TransCanada's income from Bruce Power before income taxes	**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 6 to the December 31, 2003 Consolidated Financial Statements for an explanation of the purchase price amortizations.

POWER LP INVESTMENT

Power LP Investment includes the earnings generated from TransCanada's 35.6 per cent investment in TransCanada Power, L.P., Canada's largest publicly-held, power-based income fund. Power LP owns six power plants in Canada and one in the U.S. that are fuelled by natural gas, waste heat, waste wood or a combination of these.

TransCanada acts as manager for Power LP. In this capacity, TransCanada manages the operations and maintenance requirements of Power LP, the fuel supply and associated price exposure and, when market conditions warrant, TransCanada 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 TransCanada.

Operating and other income in 2003 from TransCanada's investment in Power LP remained consistent with 2002. At December 31, 2003, Power LP units closed at $36.30 on the Toronto Stock Exchange and TransCanada owned approximately 14.0 million units.

POWER VOLUMES AND AVAILABILITY

Volumes have increased 39 per cent to 28,010 GWh in 2003 compared to 20,111 GWh in 2002 primarily due to the acquisitions of the interest in Bruce Power and ManChief. Volumes for Eastern Operations increased as a result of growth in the retail business which is focused on sales to large commercial and industrial customers. Volumes for Power LP decreased due to curtailments of off-peak production as a result of higher market prices for natural gas. This curtailment activity has resulted in lower power output from the Ontario plants compared to last year; however, overall financial contribution from these plants was higher.

Average plant availability, excluding Bruce Power, was 94 per cent in 2003 compared to 96 per cent in 2002. This slight decrease resulted primarily from scheduled maintenance at some of the plants in Western Operations. Including Bruce Power, average plant availability decreased to 90 per cent for 2003 as a result of scheduled maintenance on two Bruce Power B units.

Power Sales Volumes

(GWh)	**2003**	2002	2001
Western operations (1)	**12,296**	12,065	8,415
Eastern operations	**6,906**	5,630	4,216
Bruce Power investment (2)	**6,655**	n/a	n/a
Power LP investment	**2,153**	2,416	2,358
Total	**28,010**	20,111	14,989

(1) Sales volumes include TransCanada's share of the Sundance B PPA (50 per cent).

(2) Sales volumes reflect TransCanada's 31.6 per cent share of Bruce Power output for the period February 14, 2003 to December 31, 2003.

Weighted Average Plant Availability (1)

	2003	2002	2001
Western operations	**93%**	99%	96%
Eastern operations	**94%**	95%	96%
Bruce Power investment (2)	**83%**	n/a	n/a
Power LP investment	**96%**	94%	97%
All plants	**90%**	96%	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) TransCanada's availability reflects the period February 14, 2003 to December 31, 2003.

POWER – STRATEGY AND OUTLOOK

Strategy TransCanada is committed to growing the Power segment through the pursuit of quality acquisitions, greenfield development projects and expansion of existing businesses. Power's growth strategy is to:

- focus on low-cost base load generation and/or assets underpinned by strong contractual arrangements;
- focus on markets where it has a competitive advantage;
- use marketing and trading activities to create stable and predictable cash flows and optimize asset value; and
- apply business models that benefit from and support TransCanada's strong balance sheet.

Outlook TransCanada's Power segment has significant opportunities for growth. Growth will take place through quality acquisitions, niche development opportunities and optimization of the company's power portfolio by focusing on low-risk opportunities in known markets.

Excluding the impact of the settlement with a former counterparty in 2003 and potential variability in Bruce Power's earnings caused by changes in prices realized and plant availability, the net earnings outlook for the Power business in 2004 is expected to be similar to 2003. Earnings opportunities elsewhere in the business may be affected by factors such as fluctuating market prices for power and gas, regulatory changes, currency movements, weather, plant availability and overall stability of the power industry. Please see the following section "Power – Business Risks" for a complete discussion of these factors.

TransCanada's Power segment is in a strong position to capitalize on opportunities resulting from industry changes because of its technical expertise and business models that have proven successful to date. TransCanada's growth will continue to focus on diversifying the asset portfolio by adding plants of varying fuel sources which are on the low end of the regional dispatch cost curve and/or are underpinned with strong contractual arrangements.

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 2004 and future years. However, unexpected plant outages 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 generally operates in highly competitive, deregulated 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 beginning on page 46 of this Annual Report. TransCanada's largest exposure to sales price fluctuations is on Bruce Power's uncontracted volumes. See the section "Power – Business Risks – Uncontracted Volumes".

Regulatory 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, marketer and builder of power plants. These may be in the form of 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. TransCanada operates in both regulated and non-regulated power markets.

Weather Temperature and weather events may impact power and gas demand and create 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. In addition, the total amount and seasonality of water flows impacts the output and related earnings from hydroelectric facilities.

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 income. Bruce Power has sold approximately 1,560 MW of the expected power output for 2004. Of the remaining Power segment's portfolio, through the use of PPAs and other marketing arrangements, TransCanada has sold approximately 90 per cent of the expected power output in 2004 and 70 to 80 per cent for the years 2005 to 2007.

CORPORATE

HIGHLIGHTS

Lower Net Expenses Net expenses in 2003 decreased $11 million or 21 per cent from 2002.

Corporate Results-at-a-Glance

Year ended December 31 (millions of dollars)	**2003**	2002	2001
Indirect financial and preferred securities charges	**64**	64	62
Interest income and other	**(23)**	(12)	5
Net expenses, after tax	**41**	52	67

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

- **Indirect Financial and Preferred Securities Charges** Direct financial charges are reported in their respective business segments; these charges are primarily associated with the debt and preferred securities related to the company's Wholly-Owned Pipelines. Indirect financial charges 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.
- **Interest Income and Other** Interest income is earned on invested cash balances. Gains and losses on foreign exchange are included in interest income and other.

Net expenses, after tax, in the Corporate segment were $41 million in 2003 compared to $52 million in 2002 and $67 million in 2001. The decrease in 2003 from 2002 is primarily due to the positive impacts of a weaker U.S. dollar compared to the prior year. These positive impacts substantially offset the negative impacts of a weaker U.S. dollar reflected in other segments. The decrease in net expenses in 2002 from 2001 is primarily due to an increase in interest income and other and the positive impact of lower interest rates offset by increased Corporate financial charges resulting from the Fair Return decision.

The performance of the Canadian dollar relative to the U.S. dollar would either positively or negatively impact the Corporate segment's results. In 2004, the performance of the Canadian dollar is not expected to have a significant impact on TransCanada's consolidated financial results since the impact in the Corporate segment is anticipated to largely offset impacts in the other business segments.

LIQUIDITY AND CAPITAL RESOURCES

HIGHLIGHTS

Sustained Growth Total capital expenditures, including acquisitions and assumed debt, have exceeded $3 billion over the past three years.

Debt Reduction TransCanada's repayment of long-term debt, net of new debt issued, and redemption of debentures and preferred securities has exceeded $1.6 billion over the past three years.

Dividend Increase TransCanada's Board of Directors has increased quarterly common share dividend payments for the past four consecutive years, including a seven per cent increase to $0.29 per share from $0.27 per share for the quarter ending March 31, 2004.

Funds Generated from Operations Funds generated from continuing operations were $1.8 billion for the year ended December 31, 2003 compared to $1.8 billion and $1.6 billion for 2002 and 2001, respectively. 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 generated from operations increased in 2003 compared to the two prior years.

The company also reduced long-term debt, junior subordinated debentures and preferred securities in each of the past three years. 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, remained as strong at December 31, 2003 as compared to the past few years.

Investing Activities Capital expenditures, excluding acquisitions and assumed debt, totalled $391 million in 2003 compared to $599 million and $492 million in 2002 and 2001, 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 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, by way of two separate acquisitions, 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. During 2001, TransCanada acquired the Curtis Palmer Hydroelectric Company L.P. for $438 million and, through a partnership, acquired 50 per cent of the rights and obligations of the 706 MW Sundance B PPA for $110 million.

TransCanada's 2001 investing activities also include proceeds of $1.2 billion from the sale of non-core assets under the company's divestiture plan.

Financing Activities In 2003, TransCanada used a portion of its cash resources to repay long-term debt of $744 million, reduce notes payable by $62 million and redeem all of its outstanding US$160 million, 8.75 per cent Junior Subordinated Debentures.

In 2003, the company issued $450 million of ten year notes bearing interest at 5.65 per cent and US$350 million of ten year notes bearing interest at 4.00 per cent. The company repaid debt maturities of $486 million and reduced notes payable by $46 million in 2002 and repaid debt maturities of $793 million and redeemed preferred securities of $318 million in 2001. In 2001, TransCanada increased notes payable by $186 million.

Dividends and preferred securities charges amounting to $588 million were paid in 2003 compared to $546 million and $517 million in 2002 and 2001, respectively.

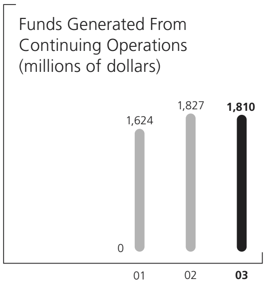
In January 2004, TransCanada's Board of Directors approved an increase in the quarterly common share dividend payment to $0.29 per share from $0.27 per share for the quarter ending March 31, 2004. This was the fourth consecutive year of dividend increase. In January 2003, the Board of Directors approved an increase in the quarterly common share dividend payment to $0.27 per share from $0.25 per share for the quarter ended March 31, 2003. In January 2002, the Board of Directors approved an increase in the quarterly common share dividend payment to $0.25 per share from $0.225 per share for the quarter ended March 31, 2002. In January 2001, TransCanada's Board of Directors approved an increase to $0.225 per share from $0.20 per share for the quarter ended March 31, 2001.

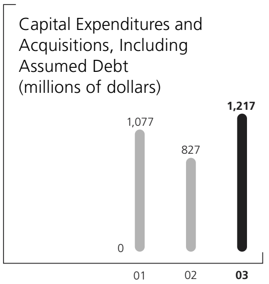
Net cash used in financing activities includes TransCanada's proportionate share of the net reduction in non-recourse debt of joint ventures amounting to $11 million in 2003 compared to $36 million and $109 million in 2002 and 2001, respectively.

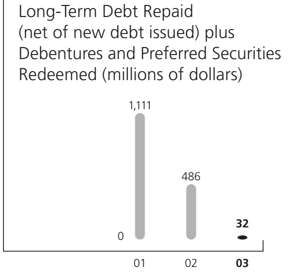
Credit Activities In 2002, TCPL filed shelf prospectuses, subsequently amended, that qualify for issuance $2 billion of common shares, preferred shares and/or debt securities including medium-term notes in Canada and US$1 billion of debt securities in the U.S., respectively. During 2003, $450 million of medium-term notes and US$350 million of senior unsecured notes were issued under these programs.

At December 31, 2003, total credit facilities of $2.2 billion were available to support the company's commercial paper program and for general corporate purposes. Of this total, $1.9 billion represents committed credit facilities of which $1.5 billion represents a syndicated facility established in December 2002. This facility is comprised of a $1.0 billion tranche with a three 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 2003, the $1.0 billion tranche to December 2006 and the $500 million tranche to December 2004. The remaining committed facilities are non-extendible, of which $60 million expires in June 2004 and $320 million expires in June 2005.

At December 31, 2003, TransCanada had used approximately $217 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, 2003 was $10.0 billion compared to $9.3 billion at December 31, 2002. TransCanada's share of total non-recourse debt of joint ventures at December 31, 2003 was $0.8 billion compared to $1.3 billion at the prior year-end. Total notes payable, including those of joint ventures, at December 31, 2003 were $367 million compared to $297 million at December 31, 2002. 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 does not extend to the rights and assets of TransCanada, except to the extent of TransCanada's investment.

At December 31, 2003, 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)	2004	2005	2006	2007	2008	2009+
Long-term debt	550	702	399	611	542	7,211
Non-recourse debt of joint ventures	19	69	55	19	19	599
Total principal repayments	569	771	454	630	561	7,810

At December 31, 2003, future annual payments, net of sub-lease receipts, under operating leases for various premises are approximately as follows.

Operating Lease Payments

Year ended December 31 (millions of dollars)	2004	2005	2006	2007	2008	2009+
Minimum lease payments	25	25	25	24	24	48
Amounts recoverable under sub-leases	(7)	(7)	(7)	(7)	(7)	(18)
Net payments	18	18	18	17	17	30

At December 31, 2003, the company's future purchase obligations are approximately as follows.

Purchase Obligations (1)

Year ended December 31 (millions of dollars)	2004	2005	2006	2007	2008	2009+
Gas Transmission						
Transportation by others (2)	167	153	84	82	74	46
Other	19	15	15	12	9	2
Power						
Commodity purchases (3)	465	280	255	260	267	2,937
Capital expenditures (4)	274	241	96	–	–	–
Other (5)	99	103	107	95	90	327
Corporate						
Information technology and other	12	–	–	–	–	–
Total purchase obligations	1,036	792	557	449	440	3,312

(1) The amounts in this table exclude funding contributions to the company's pension plans and TransCanada's one-third share of project definition phase costs in the Mackenzie Gas Pipeline Project.

(2) Rates are based on known 2004 levels. Beyond 2004, demand rates are subject to change. The contractual obligations in the table are based on 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.

TransCanada expects to make funding contributions to the company's pension plans in the amount of approximately $80 million during 2004. The expected decrease in funding in 2004 from the $110 million in 2003 is due to one-time plan design changes and investment performance above long-term expectations in 2003 partially offset by continued reductions in discount rates used to calculate plan liabilities.

At December 31, 2003, TransCanada held a 35.6 per cent interest in Power LP which is a publicly-held limited partnership. On June 30, 2017, the partnership will redeem all units outstanding, not held directly or indirectly by TransCanada, at their then fair market value, being the average of the fair market values assigned thereto by independent valuators, plus all declared and unpaid distributions of distributable cash thereon (the Redemption Price). TransCanada is required to fund the Redemption Price in accordance with the terms of the Power LP Partnership Agreement.

TransCanada has established a $50 million operating line of credit to Power LP, available on a revolving basis. As at December 31, 2003, the amount borrowed against this line of credit was $26 million compared to $37 million at December 31, 2002.

At December 31, 2003, 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 (TransCanada Credit Facility) with a subsidiary of TransCanada. At December 31, 2003 and 2002, the partnership had no amount outstanding under the TransCanada Credit Facility.

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 then connect with the Alberta System. Under the agreement, TransCanada has agreed to finance the APG for its one-third share of project definition phase costs. This share is estimated to be approximately $90 million over three years. In the year ended December 31, 2003, TransCanada funded $34 million of this loan. The ability to recover this investment is contingent upon the outcome of the project.

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, 2003.

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, 2003 was estimated to be approximately $215 million. The terms of the guarantees range from 2004 to 2018. The current carrying amount of the liability related to these guarantees is nil and the fair value is approximately $4 million.

TransCanada has guaranteed the equity undertaking of a subsidiary which supports the payment, under certain conditions, of principal and interest on the US$195 million 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.

Contingencies The Canadian Alliance of Pipeline Landowners' Associations and two individual landowners commenced an action under Ontario's Class Proceedings Act, 1992, against TransCanada and Enbridge Inc. for damages alleged in 2002 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 gains or losses on the corresponding hedged transactions. The recognition of gains and losses on derivatives used as hedges for the Alberta System, Canadian Mainline 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 the derivatives, realized and unrealized, are included in the foreign exchange adjustment account in Shareholders' Equity as a reduction of the corresponding gains and losses on the translation of the assets and liabilities of the foreign subsidiaries. Carrying amounts for interest rate swaps represent the net accrued interest from the last payment date to the reporting date. 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. These fair values approximate the amount that the company would receive or pay if the instruments were closed out at these dates. The fair values of power, natural gas and heat rate derivatives have been calculated at year-end 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, 2003 and 2002, 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 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.

	2003		2002	
Asset/(Liability) at December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Foreign Exchange				
Cross-currency swaps – U.S. dollars	**65**	**65**	(8)	(8)
Forward foreign exchange contracts – U.S. dollars	**2**	**3**	(4)	(4)

At December 31, 2003, the notional principal amounts of cross-currency swaps were US$250 million (2002 – US$350 million), principal amounts of forward foreign exchange contracts were US$125 million (2002 – US$225 million). In addition, the company has associated interest rate swaps with notional principal amounts of $311 million (2002 – $309 million) and US$200 million (2002 – US$350 million). The fair value of these interest rate swaps was $1 million (2002 – $(4) million).

Reconciliation of Foreign Exchange Adjustment

December 31 (millions of dollars)	**2003**	2002
Balance at beginning of year	**14**	13
Translation (losses)/gains on foreign currency denominated net assets	**(136)**	3
Foreign exchange gains/(losses) on derivatives, and other	**82**	(2)
	(40)	14

Foreign Exchange and Interest Rate Management Activity The company manages the foreign exchange risk of U.S. dollar debt, U.S. dollar expenses and the interest rate exposures of the Alberta System, the Canadian Mainline 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.

	2003		2002	
Asset/(Liability) at December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Foreign Exchange				
Cross-currency swaps	**(26)**	**(26)**	56	56
Interest Rate				
Interest rate swaps				
Canadian dollars	**2**	**15**	4	56
U.S. dollars	**–**	**8**	(1)	4

At December 31, 2003, the notional principal amounts of cross-currency swaps were US$282 million (2002 – US$282 million) and the notional principal amounts for interest rate swaps were $964 million (2002 – $874 million) and US$100 million (2002 – US$175 million).

The company manages the foreign exchange risk and interest rate exposure of its other U.S. dollar debt through the use of foreign currency and interest rate derivatives. The fair values of the interest rate derivatives are shown in the table below.

	2003		2002	
Asset/(Liability) at December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Interest Rate				
Interest rate swaps U.S. dollars	**2**	**37**	2	55

At December 31, 2003, the notional principal amount for interest rate swaps was US$500 million (2002 – US$400 million).

Energy Price Risk Management The company executes power, natural gas and heat rate derivatives for overall management of its asset portfolio. The company's portfolio of power, natural gas and heat rate derivatives is primarily comprised of swap, option and forward contracts, with fixed and floating price commitments. 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.

	2003		2002	
Asset/(Liability) at December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Power – swaps	**(5)**	**(5)**	(36)	(36)
Gas – swaps, forwards and options	**(35)**	**(35)**	(28)	(28)
Heat rate contracts	**61**	**61**	74	74

	Power (GWh)[1]		Gas (Bcf)[1]	
Notional Volumes at December 31, 2003	**Purchases**	**Sales**	**Purchases**	**Sales**
Power – swaps	**1,390**	**4,864**	**–**	**–**
Gas – swaps, forwards and options	**–**	**–**	**86.1**	**88.2**
Heat rate contracts	**2,331**	**735**	**1.0**	**20.3**

	Power (GWh)		Gas (Bcf)	
Notional Volumes at December 31, 2002	Purchases	Sales	Purchases	Sales
Power – swaps	467	5,138	–	–
Gas – swaps, forwards and options	–	–	86.3	88.6
Heat rate contracts	2,848	–	–	24.8

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

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 these activities. A strong commitment to a risk management culture by 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 policy 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 to the Audit Committee of TransCanada's Board of Directors regularly.

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 under Credit Risk in Note 11 to the Consolidated Financial Statements.

Risks and Risk Management Related to the Kyoto Protocol The Canadian government continues to develop climate change policy that will help it meet its commitment under the Kyoto Protocol. While broad policy mechanisms such as the Domestic Emissions Trading Program for Large Final Emitters have been identified, program details are still undefined. Once these details are finalized, TransCanada will be better able to assess the implications on the company.

Over the past several years, TransCanada's focus has been, and continues to be, on developing practical options for reducing greenhouse gas (GHG) emissions from the company's facilities. This is being achieved through technical and operational improvements, driven in large part by increased fuel and system efficiencies and the elimination of methane emissions. TransCanada's current position is that operating initiatives that reduce GHG at the source are more appropriate than other mechanisms.

Disclosure Controls and Procedures and Internal Controls Pursuant to the Sarbanes-Oxley Act as adopted by the U.S. Securities and Exchange Commission, 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 or in other factors that could significantly affect internal controls subsequent to the date on which such evaluation was completed in connection with this Annual Report.

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 achieve a proper matching of revenues and expenses, the timing of recognition of certain expenses and revenues may differ from that otherwise expected under GAAP. The two most significant examples of this relate to the recording of income taxes on the taxes payable basis and the deferral of foreign exchange losses as outlined in the Consolidated Financial Statements' Note 12 and Note 7, respectively.

CRITICAL ACCOUNTING ESTIMATES

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 estimates are:

Deferred After-Tax Gains and Remaining Obligations Related to the Gas Marketing Business TransCanada mitigated certain of its remaining exposures associated with the contingent liabilities related to the divested Gas Marketing operations by acquiring from a subsidiary of Mirant Corporation (Mirant) certain contracts under which it still had exposure in 2003, and simultaneously hedging the market price exposures of these contracts. To determine the exposure to these contracts, the company uses estimates, including future market prices, transportation volumes, transportation charges and income taxes. The company remains contingently liable for certain residual obligations. This obligation is further described in Discontinued Operations on page 50 of this Annual Report.

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, 2003 was $914 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 therefore have no material impact on TransCanada's net income but would directly impact funds generated from operations.

ACCOUNTING CHANGES

Hedging Relationships In November 2001, the Accounting Standards Board (AcSB) of the Canadian Institute of Chartered Accountants (CICA) issued an 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 AcSB amended this guideline in June 2003 to clarify some aspects and to add an appendix of implementation guidance. The rules under this guideline are substantially similar to the corresponding requirements under Statement of Financial Accounting Standards (SFAS) No. 133 which was adopted by the company for U.S. GAAP purposes, effective January 1, 2001. This accounting guideline will be effective for the company as of January 1, 2004 on a prospective basis. TransCanada does not expect the new Canadian requirement to have a significant impact on the company's Consolidated Financial Statements.

Disposal of Long-Lived Assets and Discontinued Operations In November 2002, the CICA issued a new Handbook Section "Disposal of Long-Lived Assets and Discontinued Operations". This section establishes new standards for the recognition, measurement, presentation and disclosure of the disposal of long-lived assets. It also establishes standards for the presentation and disclosure of discontinued operations, whether or not they include long-lived assets. This section was effective for the company on a prospective basis after May 1, 2003 and did not result in restatement of income for prior periods.

Impairment of Long-Lived Assets In November 2002, the CICA issued a 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. This section will be effective for the company as of January 1, 2004 and is not expected to have a significant impact on the company's Consolidated Financial Statements.

Asset Retirement Obligations In January 2003, the 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 standard is substantially similar to the corresponding requirements under SFAS No. 143 which was adopted by the company for U.S. GAAP purposes, effective January 1, 2003. This section will be effective for TransCanada as of January 1, 2004. The impact of this standard has been outlined in Note 18 to the Consolidated Financial Statements.

Consolidation of Variable Interest Entities In June 2003, the AcSB 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 disclosure requirements are effective as of January 1, 2004 and the consolidation 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.

Generally Accepted Accounting Principles In July 2003, the CICA issued a 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. This section will be effective for the company as of January 1, 2004 and will require the recognition of additional regulated assets and liabilities but is not expected to have a significant impact on the company's net income.

General Standards of Financial Statement Presentation In July 2003, the CICA issued a new Handbook Section "General Standards of Financial Statement Presentation" which clarifies what constitutes "fair presentation in accordance with GAAP". This section will be effective for the company as of January 1, 2004 and is not expected to have an impact on the company's Consolidated Financial Statements.

OTHER INFORMATION

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

Other selected consolidated financial information for the years ended December 31, 2003, 2002, 2001 and 2000 is found under the heading "Four-Year Financial Highlights" on pages 90 and 91 of this Annual Report.

DISCONTINUED OPERATIONS

FINANCIAL REVIEW

TransCanada's Board of Directors approved a plan to dispose of the company's International, Canadian Midstream, and certain other businesses (December Plan) and the disposal of the Gas Marketing business in December 1999 and July 2001, respectively. The company's disposals under both plans were substantially completed at December 31, 2001.

The company's investments in Gasoducto del Pacifico, INNERGY Holdings S.A. and P.T. Paiton Energy Company approved for disposal under the December Plan will be accounted for as part of continuing operations as of December 31, 2003 due to the length of time it has taken the company to dispose of these assets. It is the intention of the company to continue with its plan to dispose of these investments.

In 2003, the company reviewed the provision for loss on discontinued operations and the deferred gain, taking into consideration the impacts of Mirant filing for bankruptcy protection and the mitigation of certain contingent liabilities referred to below. As a result of this review, TransCanada recognized in income in 2003 $50 million of the original approximately $100 million after-tax deferred gain. Any further adjustments to the estimate of the net loss on disposal and the deferred gain will be recognized as a gain or loss from discontinued operations in the period that such changes are determined.

The company's net income/(loss) from discontinued operations in 2002 was nil as the existing provision for loss on discontinued operations was reviewed by the company's management and determined to be appropriate. The company recorded a net loss from discontinued operations in 2001 of $67 million. This amount includes a net loss of $90 million based on management's estimates of proceeds and disposal costs and net earnings of $3 million prior to plan approval, related to the Gas Marketing business. Also included in 2001 is a positive $20 million after-tax adjustment to the December Plan.

TransCanada remains contingently liable pursuant to guarantees and obligations under certain contracts that relate to the divested Gas Marketing business. In accordance with the terms of these contracts and in the normal course of business, the company expects the underlying volumes related to the contracts to decrease over time. The contingent liability under these obligations is contingent on certain future events, the occurrence and the amount of which is not determinable. The purchasers of the Gas Marketing business have agreed to indemnify TransCanada in the event the company is called upon to perform under the obligations.

Selected Three Year Consolidated Financial Data (1)

(millions of dollars except per share amounts)	2003	2002	2001
Income Statement			
Revenues	**5,357**	5,214	5,275
Net income			
Continuing operations	**801**	747	686
Discontinued operations	**50**	–	(67)
Total	**851**	747	619
Balance Sheet			
Total assets	**20,544**	19,966	19,905
Long-term debt	**9,465**	8,815	9,347
Non-recourse debt of joint ventures	**761**	1,222	1,295
Preferred securities	**22**	238	237
Per Common Share Data			
Net income – Basic			
Continuing operations	**$ 1.66**	$ 1.56	$ 1.44
Discontinued operations	**0.10**	–	(0.14)
	$ 1.76	$ 1.56	$ 1.30
Net income – Diluted	**$ 1.76**	$ 1.55	$ 1.30
Dividends declared	**$ 1.08**	$ 1.00	$ 0.90

(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 17 of TransCanada's 2003 Audited Consolidated Financial Statements.

Selected Quarterly and Annual Consolidated Financial Data [1]

(millions of dollars except per share amounts)	First	Second	Third	Fourth	Annual
2003					
Revenues	**1,336**	**1,311**	**1,391**	**1,319**	**5,357**
Net income					
Continuing operations	**208**	**202**	**198**	**193**	**801**
Discontinued operations	**–**	**–**	**50**	**–**	**50**
	208	**202**	**248**	**193**	**851**
Share Statistics					
Net income per share – Basic					
Continuing operations	**$ 0.43**	**$ 0.42**	**$ 0.41**	**$ 0.40**	**$ 1.66**
Discontinued operations	**–**	**–**	**0.10**	**–**	**0.10**
	$ 0.43	**$ 0.42**	**$ 0.51**	**$ 0.40**	**$ 1.76**
Net income per share – Diluted	**$ 0.43**	**$ 0.42**	**$ 0.51**	**$ 0.40**	**$ 1.76**
Dividend declared per common share	**$ 0.27**	**$ 0.27**	**$ 0.27**	**$ 0.27**	**$ 1.08**
2002					
Revenues	1,246	1,345	1,285	1,338	5,214
Net income					
Continuing operations	187	205	175	180	747
Discontinued operations	–	–	–	–	–
	187	205	175	180	747
Share Statistics					
Net income per share – Basic					
Continuing operations	$ 0.39	$ 0.43	$ 0.37	$ 0.37	$ 1.56
Discontinued operations	–	–	–	–	–
	$ 0.39	$ 0.43	$ 0.37	$ 0.37	$ 1.56
Net income per share – Diluted	$ 0.39	$ 0.43	$ 0.36	$ 0.37	$ 1.55
Dividend declared per common share	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 1.00

(1) The selected quarterly and annual 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 17 of TransCanada's 2003 Audited Consolidated Financial Statements.

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 U.S. Securities and Exchange Commission. 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.

2003 Consolidated Financial Statements

STRONG

RESULTS

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 (MD&A) which is based on the Company's financial results prepared in accordance with Canadian GAAP. It compares the Company's financial performance in 2003 to 2002 and should be read in conjunction with the consolidated financial statements and accompanying notes. In addition, significant changes between 2002 and 2001 are highlighted. Note 18 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 consolidated financial statements with Management and the external auditors 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 generally accepted accounting principles. The report of KPMG LLP on page 59 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 23, 2004

CONSOLIDATED INCOME

Year ended December 31 (millions of dollars except per share amounts)	**2003**	2002	2001
Revenues	**5,357**	5,214	5,275
Operating Expenses			
Cost of sales	**692**	627	712
Other costs and expenses	**1,682**	1,546	1,618
Depreciation	**914**	848	793
	3,288	3,021	3,123
Operating Income	**2,069**	2,193	2,152
Other Expenses/(Income)			
Financial charges (Note 7)	**821**	867	889
Financial charges of joint ventures	**77**	90	107
Equity income (Note 6)	**(165)**	(33)	(24)
Interest and other income	**(60)**	(53)	(53)
	673	871	919
Income from Continuing Operations before Income Taxes and Non-Controlling Interests	**1,396**	1,322	1,233
Income Taxes (Note 12)	**535**	517	480
Non-Controlling Interests (Note 9)	**60**	58	67
Net Income from Continuing Operations	**801**	747	686
Net Income/(Loss) from Discontinued Operations (Note 17)	**50**	–	(67)
Net Income	**851**	747	619
Net Income/(Loss) Per Share (Note 10)			
Continuing operations	**$1.66**	$1.56	$1.44
Discontinued operations	**0.10**	–	(0.14)
Basic	**$1.76**	$1.56	$1.30
Diluted	**$1.76**	$1.55	$1.30

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)	**2003**	2002	2001
Cash Generated from Operations			
Net income from continuing operations	**801**	747	686
Depreciation	**914**	848	793
Future income taxes	**230**	247	127
Equity income in excess of distributions received	**(128)**	(6)	–
Non-controlling interests	**60**	58	67
Other	**(67)**	(67)	(49)
Funds generated from continuing operations	**1,810**	1,827	1,624
Decrease in operating working capital (Note 15)	**112**	33	170
Net cash provided by continuing operations	**1,922**	1,860	1,794
Net cash (used in)/provided by discontinued operations	**(17)**	59	(659)
	1,905	1,919	1,135
Investing Activities			
Capital expenditures	**(391)**	(599)	(492)
Acquisitions, net of cash acquired	**(570)**	(228)	(585)
Disposition of assets	**–**	–	1,170
Deferred amounts and other	**(190)**	(115)	30
Net cash (used in)/provided by investing activities	**(1,151)**	(942)	123
Financing Activities			
Dividends and preferred securities charges	**(588)**	(546)	(517)
Notes payable (repaid)/issued, net	**(62)**	(46)	186
Long-term debt issued	**930**	–	–
Reduction of long-term debt	**(744)**	(486)	(793)
Non-recourse debt of joint ventures issued	**60**	44	23
Reduction of non-recourse debt of joint ventures	**(71)**	(80)	(132)
Redemption of junior subordinated debentures	**(218)**	–	–
Common shares issued	**65**	50	24
Partnership units of joint ventures issued	**–**	–	59
Preferred securities redeemed	**–**	–	(318)
Net cash used in financing activities	**(628)**	(1,064)	(1,468)
Increase/(Decrease) in Cash and Short-Term Investments	**126**	(87)	(210)
Cash and Short-Term Investments			
Beginning of year	**212**	299	509
Cash and Short-Term Investments			
End of year	**338**	212	299

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

CONSOLIDATED BALANCE SHEET

December 31 (millions of dollars)	2003	2002
ASSETS		
Current Assets		
Cash and short-term investments	**338**	212
Accounts receivable	**605**	691
Inventories	**165**	178
Other	**88**	107
	1,196	1,188
Long-Term Investments (Note 6)	**733**	345
Plant, Property and Equipment (Notes 3, 7 and 8)	**17,451**	17,496
Other Assets (Note 4)	**1,164**	937
	20,544	19,966
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable (Note 13)	**367**	297
Accounts payable	**1,025**	990
Accrued interest	**208**	227
Current portion of long-term debt (Note 7)	**550**	517
Current portion of non-recourse debt of joint ventures (Note 8)	**19**	75
	2,169	2,106
Deferred Amounts	**466**	549
Long-Term Debt (Note 7)	**9,465**	8,815
Future Income Taxes (Note 12)	**427**	226
Non-Recourse Debt of Joint Ventures (Note 8)	**761**	1,222
Preferred Securities (Note 9)	**22**	238
	13,310	13,156
Non-Controlling Interests (Note 9)	**1,143**	1,063
Shareholders' Equity		
Common shares (Note 10)	**4,679**	4,614
Contributed surplus	**267**	265
Retained earnings	**1,185**	854
Foreign exchange adjustment (Note 11)	**(40)**	14
	6,091	5,747
Commitments, Contingencies and Guarantees (Note 16)		
	20,544	19,966

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

On behalf of the Board:

Harold N. Kvisle
Director

Harry G. Schaefer
Director

CONSOLIDATED RETAINED EARNINGS

Year ended December 31 (millions of dollars)	**2003**	2002	2001
Balance at beginning of year	**854**	586	395
Net income	**851**	747	619
Common share dividends	**(520)**	(479)	(428)
	1,185	854	586

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

AUDITORS' REPORT

To the Shareholders of TransCanada Corporation

We have audited the consolidated balance sheets of TransCanada Corporation as at December 31, 2003 and 2002 and the consolidated statements of income, retained earnings and cash flows for each of the years in the three-year period ended December 31, 2003. 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, 2003 and 2002 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2003 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada
February 23, 2004

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

GAS TRANSMISSION

The Gas Transmission segment owns and operates a natural gas transmission system in Alberta (the Alberta System), a natural gas transmission system extending from the Alberta border east into Québec (the Canadian Mainline), a natural gas transmission system extending from the Alberta border west into southeastern British Columbia (the BC System), and a natural gas transmission system extending from central Alberta to the British Columbia, Saskatchewan and the United States borders (the Foothills System). Gas Transmission also holds the Company's investments in other natural gas pipelines in Canada and the U.S. In addition, Gas Transmission investigates and develops new natural gas transmission, 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 (Canadian GAAP). These accounting principles are different in some respects from United States generally accepted accounting principles (U.S. GAAP) and the significant differences are described in Note 18. 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 year ended December 31, 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 years ended December 31, 2002 and 2001 is that of TCPL, its subsidiaries, and its proportionate share of the accounts of its joint venture investments at that time.

On August 15, 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. On December 3, 2003, TransCanada increased its ownership interest in Portland Natural Gas Transmission System Partnership (Portland) from 43.4 per cent to 61.7 per cent. Subsequent to the acquisition, Portland was fully consolidated in the Company's financial statements with 38.3 per cent reflected in non-controlling interests.

The financial statements of TransCanada have been prepared using the continuity of interests method of accounting. Accordingly, the financial statements of TransCanada on the effective date of the plan of arrangement, on a consolidated basis, were in all material respects the same as those of TCPL immediately prior to the plan of arrangement becoming effective, except that the preferred securities and preferred shares of TCPL have been reflected as non-controlling interests in the consolidated financial statements of TransCanada. In addition, the distributions on the preferred securities and the dividends on the preferred shares have been reflected as non-controlling interest charges in determining the consolidated net income of TransCanada.

TransCanada uses the equity method of accounting for investments over which the Company is able to exercise significant influence.

Regulation The Alberta System is regulated by the Alberta Energy and Utilities Board (EUB), and 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). All Canadian natural gas transmission operations are regulated with respect to the determination of tolls, construction and operations. In December 2002, the NEB approved TransCanada's application for the Canadian Mainline to charge interim tolls for transportation service, effective January 1, 2003. In August 2003, subsequent to the NEB's decision on the 2003 Tolls and Tariff Application, it approved interim tolls for the period September 1, 2003 to December 31, 2003. The NEB determined that tolls will remain interim pending a decision from the Federal Court of Appeal on TransCanada's Fair Return Review and Variance Application. Any adjustments to the interim tolls will be recorded in accordance with the final NEB decision. The natural gas pipelines in the United States and certain power plants are also subject to the authority of regulatory bodies. In order to achieve a proper matching of revenues and expenses, the timing of recognition of certain revenues and expenses in these businesses may differ from that otherwise expected under generally accepted accounting principles.

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 the straight-line basis. Pipeline and compression equipment are depreciated at annual rates ranging from two to five per cent and metering and other plant are depreciated at various rates. Removal and site restoration costs are not determinable and will be recorded when reasonably estimable. 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 the straight-line basis over estimated service lives at average annual rates ranging from two to five per cent. Interest is capitalized on significant 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 twenty per cent.

Power Purchase Arrangements The initial payments for power purchase arrangements (PPAs) are deferred and are being amortized over the terms of the contracts, from the dates of acquisition, which range from nine to 27 years. PPAs are long-term contracts to purchase power on a predetermined basis.

Stock Options TransCanada's Key Employee Stock Incentive Plan (KESIP) permits the award of options to purchase the Company's common shares to certain key employees, some of whom are officers. The contractual life of options granted prior to 2003 and granted in 2003 is ten and seven years, respectively. 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 in 2003, 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. This method is also used for accounting purposes, since there is reasonable expectation that future taxes payable will be included in future costs of service and recorded in revenues at that time. The liability method of accounting for income taxes is used for the remainder of the Company's operations. Under this method, future tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future income tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Changes to these balances are recognized in income in the period in which they occur.

Canadian income taxes are not provided on the unremitted earnings of foreign investments which are considered to be indefinitely reinvested in foreign operations.

Foreign Currency Translation The Company's foreign operations are self-sustaining and are translated into Canadian dollars using the current rate method. Translation adjustments are reflected in the foreign exchange adjustment in Shareholders' Equity.

Exchange gains or losses on the principal amounts of foreign currency debt, junior subordinated debentures 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 gains or losses on the corresponding hedged transactions. The recognition of gains and losses on derivatives used as hedges for Alberta System, Canadian Mainline 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 the fair value of the derivative substantially offsets 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 gain or loss on the derivative is 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 gain or loss on the 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. 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. 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. 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. The units vest at the end of three years, should certain conditions be met which include the employee's continued employment during that period and achievement of specified corporate performance targets. The Company is recording compensation expense over the three year vesting period and the value of the units, net of income tax, will be paid at the end of the vesting period.

Note 2 SEGMENTED INFORMATION

Net Income/Loss (1)

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 and other income	**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 and other income	17	13	23	53
Income taxes	(458)	(84)	25	(517)
Continuing Operations	653	146	(52)	747
Discontinued Operations				–
Net Income				747

Year ended December 31, 2001 (millions of dollars)	Gas Transmission	Power	Corporate	Total
Revenues	3,880	1,395	–	5,275
Cost of sales (2)	–	(712)	–	(712)
Other costs and expenses	(1,226)	(361)	(31)	(1,618)
Depreciation	(753)	(37)	(3)	(793)
Operating income/(loss)	1,901	285	(34)	2,152
Financial charges and non-controlling interests	(856)	(15)	(85)	(956)
Financial charges of joint ventures	(98)	(9)	–	(107)
Equity income	24	–	–	24
Interest and other income	6	13	34	53
Income taxes	(392)	(106)	18	(480)
Continuing Operations	585	168	(67)	686
Discontinued Operations				(67)
Net Income				619

(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)	**2003**	2002
Gas Transmission	**16,972**	16,979
Power	**2,746**	2,391
Corporate	**815**	457
Continuing Operations	**20,533**	19,827
Discontinued Operations	**11**	139
	20,544	19,966

Geographic Information

Year ended December 31 (millions of dollars)	**2003**	2002 (4)	2001
Revenues (3)			
Canada – domestic	**3,257**	2,731	3,303
Canada – export	**1,293**	1,641	1,329
United States	**807**	842	643
	5,357	5,214	5,275

(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)	**2003**	2002
Canada	**15,193**	15,479
United States	**2,258**	2,017
	17,451	17,496

Capital Expenditures

Year ended December 31 (millions of dollars)	**2003**	2002	2001
Gas Transmission	**256**	382	285
Power	**132**	193	121
Corporate and Other	**3**	24	86
	391	599	492

Note 3 PLANT, PROPERTY AND EQUIPMENT

December 31 (millions of dollars)	**2003**			2002		
	Cost	**Accumulated Depreciation**	**Net Book Value**	Cost	Accumulated Depreciation	Net Book Value
Gas Transmission						
Alberta System						
Pipeline	**4,934**	**1,908**	**3,026**	4,922	1,755	3,167
Compression	**1,507**	**549**	**958**	1,517	479	1,038
Metering and other	**862**	**211**	**651**	919	237	682
	7,303	**2,668**	**4,635**	7,358	2,471	4,887
Under construction	**13**	**–**	**13**	4	–	4
	7,316	**2,668**	**4,648**	7,362	2,471	4,891
Canadian Mainline						
Pipeline	**8,683**	**3,176**	**5,507**	8,674	2,933	5,741
Compression	**3,318**	**832**	**2,486**	3,291	709	2,582
Metering and other	**404**	**132**	**272**	429	118	311
	12,405	**4,140**	**8,265**	12,394	3,760	8,634
Under construction	**12**	**–**	**12**	15	–	15
	12,417	**4,140**	**8,277**	12,409	3,760	8,649
Foothills (1)						
Pipeline	**834**	**286**	**548**			
Compression	**378**	**130**	**248**			
Metering and other	**185**	**115**	**70**			
	1,397	**531**	**866**			
Other Gas	**3,359**	**1,052**	**2,307**	4,191	1,633	2,558
	24,489	**8,391**	**16,098**	23,962	7,864	16,098
Power						
Power generation facilities	**1,439**	**381**	**1,058**	1,489	398	1,091
Other	**77**	**41**	**36**	77	38	39
	1,516	**422**	**1,094**	1,566	436	1,130
Under construction	**209**	**–**	**209**	204	–	204
	1,725	**422**	**1,303**	1,770	436	1,334
Corporate	**122**	**72**	**50**	120	56	64
	26,336	**8,885**	**17,451**	25,852	8,356	17,496

(1) On August 15, 2003, the Company acquired the remaining interests in Foothills previously not held by TransCanada, and Foothills was consolidated in the Company's financial statements subsequent to that date.

Note 4 OTHER ASSETS

December 31 (millions of dollars)	**2003**	2002
PPAs – Canada [1]	**278**	297
PPAs – U.S. [1]	**248**	325
Hedge contracts	**166**	99
Loans and advances	**111**	–
Pension asset	**143**	70
Other	**218**	146
	1,164	937

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

December 31 (millions of dollars)		**2003**			2002	
	Cost	**Accumulated Amortization**	**Net Book Value**	Cost	Accumulated Amortization	Net Book Value
PPAs – Canada	**329**	**51**	**278**	329	32	297
PPAs – U.S.	**276**	**28**	**248**	339	14	325

Amortization expense with respect to the PPAs was $37 million for the year ended December 31, 2003 (2002 – $28 million; 2001 – $18 million). In 2002, the Company acquired $114 million of PPAs – U.S.

Note 5 JOINT VENTURE INVESTMENTS

		TransCanada's Proportionate Share				
		Income Before Income Taxes Year ended December 31			Net Assets December 31	
(millions of dollars)	**Ownership Interest**	**2003**	2002	2001	**2003**	2002
Gas Transmission						
Great Lakes	50.0% [1]	**81**	102	89	**419**	492
Iroquois	41.0% [2]	**31**	30	27	**169**	160
TC PipeLines, LP	33.4%	**21**	24	23	**130**	158
Trans Québec & Maritimes	50.0%	**14**	13	15	**77**	79
CrossAlta	60.0% [1]	**11**	21	15	**41**	35
Foothills	[3]	**19**	29	26	**–**	204
Other	Various	**7**	7	4	**22**	17
Power						
TransCanada Power, L.P.	35.6% [4]	**25**	26	21	**234**	244
ASTC Power Partnership	50.0% [5]	**–**	–	–	**99**	105
		209	252	220	**1,191**	1,494

(1) Great Lakes Gas Transmission Limited Partnership (Great Lakes); CrossAlta Gas Storage & Services Ltd. (CrossAlta).

(2) In May 2001, the Company increased its interest in Iroquois Gas Transmission System (Iroquois) from 35.0 per cent to 41.0 per cent.

(3) On August 15, 2003, the Company acquired the remaining interests in Foothills previously not held by TransCanada, and Foothills was consolidated subsequent to that date.

(4) In October 2001, the Company's interest in TransCanada Power, L.P. decreased from 41.6 per cent to 35.6 per cent.

(5) In December 2001, the Company purchased 50.0 per cent of ASTC Power Partnership, which is located in Alberta and holds a power purchase arrangement. In 2002, the underlying power volume related to the 50.0 per cent ownership interest in the Partnership was effectively transferred to TransCanada.

Consolidated retained earnings at December 31, 2003 include undistributed earnings from these joint ventures of $509 million (2002 – $433 million).

Summarized Financial Information of Joint Ventures

Year ended December 31 (millions of dollars)	**2003**	2002	2001
Income			
Revenues	**623**	680	592
Other costs and expenses	**(275)**	(251)	(172)
Depreciation	**(96)**	(119)	(119)
Financial charges and other	**(43)**	(58)	(81)
Proportionate share of income before income taxes of joint ventures	**209**	252	220

Year ended December 31 (millions of dollars)	**2003**	2002	2001
Cash Flows			
Operations	**272**	323	279
Investing activities	**(124)**	(125)	21
Financing activities	**(156)**	(210)	(291)
Proportionate share of (decrease)/increase in cash and short-term investments of joint ventures	**(8)**	(12)	9

December 31 (millions of dollars)	**2003**	2002
Balance Sheet		
Cash and short-term investments	**55**	63
Other current assets	**122**	127
Long-term investments	**118**	148
Plant, property and equipment	**1,688**	2,503
Other assets and deferred amounts (net)	**114**	103
Current liabilities	**(94)**	(164)
Non-recourse debt	**(761)**	(1,222)
Future income taxes	**(51)**	(64)
Proportionate share of net assets of joint ventures	**1,191**	1,494

Note 6 LONG-TERM INVESTMENTS

		TransCanada's Share				
		Income From Equity Investments Year ended December 31			Equity Investments December 31	
(millions of dollars)	**Ownership Interest**	**2003**	2002	2001	**2003**	2002
Equity Investments						
Power						
Bruce Power L.P.	31.6%	**99**	–	–	**513**	–
Gas Transmission						
Northern Border	10.0% (1)	**22**	25	23	**103**	129
TransGas de Occidente S.A.	46.5%	**27**	5	2	**80**	75
Portland	61.7% (2)	**14**	2	(1)	**–**	68
Other	Various	**3**	1	–	**37**	73
		165	33	24	**733**	345

(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 from 33.3 per cent to 43.4 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, 2003 include undistributed earnings from these equity investments of $166 million (2002 – $47 million).

Investment in Bruce Power L.P. On February 14, 2003, the Company acquired a 31.6 per cent interest in Bruce Power L.P. (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 has been 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 will be 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 will be 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. The amount allocated to the pension liability will be amortized to income over the 11 year expected average remaining service life of Bruce Power employees, resulting in an annual amortization of $3 million.

Note 7 LONG-TERM DEBT

		2003		2002	
	Maturity Dates	**Outstanding December 31** (1)	**Weighted Average Interest Rate** (2)	Outstanding December 31 (1)	Weighted Average Interest Rate (2)
Alberta System					
Debentures and Notes					
Canadian dollars	2007 to 2024	**627**	**11.6%**	798	11.0%
U.S. dollars (2003 and 2002 – US$500)	2004 to 2023	**646**	**8.3%**	790	8.3%
Medium-Term Notes					
Canadian dollars	2005 to 2030	**767**	**7.4%**	767	7.4%
U.S. dollars (2003 and 2002 – US$233)	2026 to 2029	**301**	**7.7%**	368	7.7%
Unsecured Loans					
U.S. dollars (2003 – nil; 2002 – US$107)	2003	**–**		169	2.1%
		2,341		2,892	
Foreign exchange differential recoverable through the tollmaking process		**(16)**		(271)	
		2,325		2,621	
Canadian Mainline					
First Mortgage Pipe Line Bonds					
Pounds Sterling (2003 and 2002 – £25)	2007	**58**	**16.5%**	64	16.5%
Debentures					
Canadian dollars	2008 to 2020	**1,354**	**10.9%**	1,354	10.9%
U.S. dollars (2003 and 2002 – US$800)	2012 to 2023	**1,034**	**9.2%**	1,264	9.2%
Medium-Term Notes					
Canadian dollars	2004 to 2031	**2,312**	**6.9%**	2,405	7.0%
U.S. dollars (2003 and 2002 – US$120)	2010	**155**	**6.1%**	190	6.1%
		4,913		5,277	
Foreign exchange differential recoverable through the tollmaking process		**(60)**		(330)	
		4,853		4,947	
Foothills (3)					
Senior Secured Notes	2005	**80**	**4.3%**		
Senior Unsecured Notes	2005 to 2014	**300**	**4.7%**		
		380			
Portland (4)					
Senior Secured Notes					
U.S. dollars (2003 – US$271)	2018	**350**	**5.9%**		
Other					
Medium-Term Notes					
Canadian dollars	2005 to 2030	**592**	**6.2%**	342	6.6%
U.S. dollars (2003 and 2002 – US$665)	2004 to 2025	**859**	**6.8%**	1,050	6.8%
Subordinated Debentures					
U.S. dollars (2003 and 2002 – US$57)	2006	**74**	**9.1%**	90	9.1%
Unsecured Loans, Debentures and Notes					
Canadian dollars	2003	**–**		110	8.4%
U.S. dollars (2003 – US$446; 2002 – US$109)	2006 to 2013	**582**	**4.9%**	172	8.3%
		2,107		1,764	
		10,015		9,332	
Less: Current Portion of Long-Term Debt		**550**		517	
		9,465		8,815	

(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: Alberta System U.S. dollar unsecured loans in 2002 – 8.3 per cent; Foothills senior unsecured notes – 5.8 per cent; Portland senior secured notes – 6.2 per cent; Other U.S. dollar subordinated debentures – 9.0 per cent (2002 – 9.0 per cent); and Other U.S. dollar unsecured loans, debentures and notes – 5.2 per cent.

(3) On August 15, 2003, the Company acquired the remaining interests in Foothills previously not held by TransCanada, and Foothills was consolidated in the Company's financial statements subsequent to that date.

(4) On December 3, 2003, TransCanada increased its ownership interest in Portland from 43.4 per cent to 61.7 per cent. The investment was fully consolidated in the Company's financial statements subsequent to that date.

Principal Repayments Principal repayments on the long-term debt of the Company approximate: 2004 – $550 million; 2005 – $702 million; 2006 – $399 million; 2007 – $611 million; and 2008 – $542 million.

Universal Shelf Programs At December 31, 2003, $1.6 billion of common shares, preferred shares and/or debt securities including medium-term notes could be issued under a universal shelf program in Canada and US$650 million of debt securities could be issued under a universal shelf program in the U.S. During 2003, $450 million of medium-term notes and US$350 million of senior unsecured notes were issued under these programs.

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, 2003.

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.

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 the Company's present and future gas transportation contracts.

FOOTHILLS

Senior Secured Notes Foothills has issued and pledged to the banks a demand debenture in the principal amount of $200 million as security for funds advanced under the credit agreement. Foothills has also granted a floating charge on its undertakings, property and assets.

OTHER

Medium-Term Notes Medium-term notes amounting to US$145 million and $150 million have retraction provisions which entitle the holders to require redemption of the principal plus accrued and unpaid interest in 2004 and 2005, respectively. The Company also has the option to redeem the US$145 million medium-term notes in 2004. If the U.S. dollar medium-term notes remain outstanding, the interest rate will change in 2004 from 6.4 per cent to 6.1 per cent plus a market-based corporate credit spread.

Financial Charges

Year ended December 31 (millions of dollars)	**2003**	2002	2001
Interest on long-term debt	**801**	850	890
Regulatory deferrals and amortizations	**(14)**	(17)	(30)
Short-term interest and other financial charges	**34**	34	38
	821	867	898
Financial charges – discontinued operations	**–**	–	(9)
	821	867	889

The Company made interest payments of $846 million for the year ended December 31, 2003 (2002 – $866 million; 2001 – $936 million). The Company capitalized $9 million of interest for the year ended December 31, 2003 (2002 and 2001 – nil).

Note 8 NON-RECOURSE DEBT OF JOINT VENTURES

		2003		2002	
	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					
(2003 – US$240; 2002 – US$261)	2011 to 2030	**310**	**7.9%**	412	8.0%
Iroquois					
Senior Unsecured Notes					
(2003 and 2002 – US$151)	2010 to 2027	**196**	**7.5%**	239	7.5%
Bank Loan					
(2003 – US$43; 2002 – US$16)	2008	**56**	**2.3%**	25	3.2%
Foothills (3)					
Senior Unsecured Notes				325	3.3%
Senior Secured Notes				62	6.7%
Trans Québec & Maritimes					
Bonds	2005 to 2010	**143**	**7.3%**	143	7.3%
Term Loan	2006	**34**	**3.5%**	40	2.8%
TC PipeLines, LP					
Senior Unsecured Notes (2002 – US$4)		**–**		6	3.0%
Other	2004 to 2012	**41**	**5.4%**	45	5.6%
		780		1,297	
Less: Current Portion of Non-Recourse Debt of Joint Ventures		**19**		75	
		761		1,222	

(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, 2003, the effective weighted average interest rate on the bank loan of Iroquois resulting from a swap agreement is 4.5 per cent (2002 – 4.8 per cent).

(3) On August 15, 2003, the Company acquired the remaining interests in Foothills previously not held by TransCanada, and Foothills was consolidated in the Company's financial statements subsequent to that date.

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: 2004 – $19 million; 2005 – $69 million; 2006 – $55 million; 2007 – $19 million; and 2008 – $19 million.

The Company's proportionate share of the interest payments of joint ventures was $67 million for the year ended December 31, 2003 (2002 – $88 million; 2001 – $100 million).

Note 9 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)	**2003**	2002
Preferred securities of subsidiary	**672**	674
Preferred shares of subsidiary	**389**	389
Other	**82**	–
	1,143	1,063

The Company's non-controlling interests included in the Consolidated Income Statement are as follows:

Year ended December 31 (millions of dollars)	**2003**	2002	2001
Preferred securities charges	**36**	36	45
Preferred share dividends	**22**	22	22
Other	**2**	–	–
	60	58	67

Preferred Securities of Subsidiary The US$460 million 8.25 per cent Preferred Securities of subsidiary (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, 2003, the debt component of the Preferred Securities is $22 million (US$14 million) (2002 – $20 million (US$13 million)) and the non-controlling interest component of the Preferred Securities is $672 million (US$446 million) (2002 – $674 million (US$447 million)).

Preferred Shares of Subsidiary

December 31	Number of Shares	Dividend Rate Per Share	Redemption Price Per Share	**2003**	2002
	(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 subsidiary 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.

Junior Subordinated Debentures On July 3, 2003, the Company redeemed the US$160 million, 8.75 per cent Junior Subordinated Debentures. Holders of these debentures received US$25.0122 per US$25.00 of the principal amount, which included accrued and unpaid interest to the redemption date, without premium or penalty. At December 31, 2002, Preferred Securities included $218 million of Junior Subordinated Debentures.

Note 10 COMMON SHARES

	Number of Shares	Amount
	(thousands)	(millions of dollars)
Outstanding at January 1, 2001	474,913	4,540
Exercise of options	1,718	24
Outstanding at December 31, 2001	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**

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 481.5 million and 483.9 million (2002 – 478.3 million and 480.7 million; 2001 – 475.8 million and 477.6 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 KESIP.

Stock Options

	Number of Options	Weighted Average Exercise Prices	Options Exercisable
	(thousands)		(thousands)
Outstanding at January 1, 2001	15,391	$18.25	12,102
Granted	2,142	$18.07	
Exercised	(1,718)	$14.08	
Cancelled or expired	(1,365)	$21.45	
Outstanding at December 31, 2001	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**

The following table summarizes information for stock options outstanding at December 31, 2003.

	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	1,557	5.8	$11.85	1,557	$11.85
$18.01 to $19.00	1,924	6.9	$18.17	1,548	$18.20
$19.16 to $20.58	1,820	4.9	$20.14	1,796	$20.15
$20.59 to $21.86	2,070	7.9	$21.41	1,180	$21.39
$22.33 to $22.85	1,535	9.0	$22.36	101	$22.79
$24.49 to $25.53	1,449	4.4	$24.58	1,406	$24.55
	10,355	6.5	$19.73	7,588	$19.09

At December 31, 2003, an additional five million common shares have been reserved for future issuance under KESIP. In 2003, TransCanada issued 1,503,200 options to purchase common shares at a weighted average price of $22.42 under the Company's KESIP and the weighted average fair value of each option was $2.54. The Company used the Black-Scholes model for these calculations with the weighted average assumptions being four years of expected life, 4.1 per cent interest rate, 18 per cent volatility and 4.5 per cent dividend yield. The amount expensed for stock options, with a corresponding increase in contributed surplus for the year ended December 31, 2003, was $2 million (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 11 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 the derivatives, realized and unrealized, are included in the foreign exchange adjustment account in Shareholders' Equity as a reduction of the corresponding gains and losses on the translation of the assets and liabilities of the foreign subsidiaries. Carrying amounts for interest rate swaps represent the net accrued interest from the last payment date to the reporting date. 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. These fair values approximate the amount that the Company would receive or pay if the instruments were closed out at these dates.

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 and credit exposure limits. At December 31, 2003, for foreign currency and interest rate derivatives, total credit risk and the largest credit exposure to a single counterparty were $127 million and $29 million, respectively. At December 31, 2003, for power, natural gas and heat rate derivatives, total credit risk and the largest credit exposure to a single counterparty were $67 million and $61 million, respectively.

Notional 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, 2003 and 2002, 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 Company's portfolio of foreign investment derivatives is comprised of contracts for periods up to four years. The fair values shown in the table below 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.

Asset/(Liability)

	2003		2002	
December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Foreign Exchange				
Cross-currency swaps				
U.S. dollars	**65**	**65**	(8)	(8)
Forward foreign exchange contracts				
U.S. dollars	**2**	**3**	(4)	(4)

At December 31, 2003, the notional principal amounts of cross-currency swaps were US$250 million (2002 – US$350 million) and principal amounts of forward foreign exchange contracts were US$125 million (2002 – US$225 million). In addition, the Company has associated interest rate swaps with notional principal amounts of $311 million (2002 – $309 million) and US$200 million (2002 – US$350 million). The fair value of these interest rate swaps was $1 million (2002 – $(4) million).

Reconciliation of Foreign Exchange Adjustment

December 31 (millions of dollars)	**2003**	2002
Balance at beginning of year	**14**	13
Translation (losses)/gains on foreign currency denominated net assets	**(136)**	3
Foreign exchange gains/(losses) on derivatives, and other	**82**	(2)
	(40)	14

Foreign Exchange Gains/(Losses) Foreign exchange gains/(losses) included in Other Expenses/(Income) for the year ended December 31, 2003 are $(2) million (2002 – $(12) million; 2001 – $1 million).

Foreign Exchange and Interest Rate Management Activity The Company manages the foreign exchange risk of U.S. dollar debt, U.S. dollar expenses and the interest rate exposures of the Alberta System, the Canadian Mainline and the Foothills System through the use of foreign currency and interest rate derivatives. These derivatives are comprised of contracts for periods up to nine years. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms.

Asset/(Liability)

	2003		2002	
December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Foreign Exchange				
Cross-currency swaps	**(26)**	**(26)**	56	56
Interest Rate				
Interest rate swaps				
Canadian dollars	**2**	**15**	4	56
U.S. dollars	**–**	**8**	(1)	4

At December 31, 2003, the notional principal amounts of cross-currency swaps were US$282 million (2002 – US$282 million) and the notional principal amounts for interest rate swaps were $964 million (2002 – $874 million) and US$100 million (2002 – US$175 million).

The Company manages the foreign exchange risk and interest rate exposure of its Other U.S. dollar debt through the use of foreign currency and interest rate derivatives. These derivatives are comprised of contracts for periods up to ten years. The fair values of the interest rate derivatives are shown in the table below.

Asset/(Liability)

	2003		2002	
December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Interest Rate				
Interest rate swaps				
U.S. dollars	**2**	**37**	2	55

At December 31, 2003, the notional principal amount for interest rate swaps was US$500 million (2002 – US$400 million).

Energy Price Risk Management The Company executes power, natural gas and heat rate derivatives for overall management of its asset portfolio. The Company's portfolio of power, natural gas and heat rate derivatives is primarily comprised of swap, option and forward contracts for periods of up to 13 years, with fixed and floating price commitments. Heat rate contracts are contracts for the sale or purchase of power that are priced based on a natural gas index. The fair values of power, natural gas and heat rate derivatives have been calculated at year-end using estimated forward prices for the relevant period. The fair values and notional volumes of the swap, option, forward and heat rate contracts are shown in the tables below.

Asset/(Liability)

	2003		2002	
December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Power – swaps	**(5)**	**(5)**	(36)	(36)
Gas – swaps, forwards and options	**(35)**	**(35)**	(28)	(28)
Heat rate contracts	**61**	**61**	74	74

Notional Volumes

	Power (GWh) (1)		**Gas (Bcf) (1)**	
December 31, 2003	**Purchases**	**Sales**	**Purchases**	**Sales**
Power – swaps	**1,390**	**4,864**	**–**	**–**
Gas – swaps, forwards and options	**–**	**–**	**86.1**	**88.2**
Heat rate contracts	**2,331**	**735**	**1.0**	**20.3**

	Power (GWh)		Gas (Bcf)	
December 31, 2002	Purchases	Sales	Purchases	Sales
Power – swaps	467	5,138	–	–
Gas – swaps, forwards and options	–	–	86.3	88.6
Heat rate contracts	2,848	–	–	24.8

(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

	2003		2002	
December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Long-Term Debt				
Alberta System	**2,341**	**2,893**	2,892	3,420
Canadian Mainline	**4,913**	**5,922**	5,277	6,080
Foothills (1)	**380**	**382**		
Portland (2)	**350**	**348**		
Other	**2,107**	**2,214**	1,764	1,904
Non-Recourse Debt of Joint Ventures	**780**	**889**	1,297	1,427
Preferred Securities	**19**	**19**	274	276

(1) On August 15, 2003, TransCanada acquired the remaining interests in Foothills previously not held by TransCanada, and Foothills was consolidated in the Company's financial statements subsequent to that date.

(2) On December 3, 2003, TransCanada increased its ownership interest in Portland from 43.4 per cent to 61.7 per cent. The investment was fully consolidated in the Company's financial statements subsequent to that date.

These fair values are provided solely for information purposes and are not recorded in the Consolidated Balance Sheet.

Note 12 INCOME TAXES

Provision for Income Taxes

Year ended December 31 (millions of dollars)	**2003**	2002	2001
Current			
Canada	**264**	229	307
Foreign	**41**	41	46
	305	270	353
Future			
Canada	**183**	193	70
Foreign	**47**	54	57
	230	247	127
	535	517	480

Geographic Components of Income

Year ended December 31 (millions of dollars)	2003	2002	2001
Canada	**1,115**	1,042	933
Foreign	**281**	280	300
Income from continuing operations before income taxes	**1,396**	1,322	1,233

Reconciliation of Income Tax Expense

Year ended December 31 (millions of dollars)	2003	2002	2001
Income from continuing operations before income taxes	**1,396**	1,322	1,233
Federal and provincial statutory tax rate	**36.7%**	39.2%	42.1%
Expected income tax expense	**512**	518	519
Unrecorded future income taxes related to regulated operations	**29**	(8)	(55)
Lower effective foreign tax rates	**(2)**	(13)	(13)
Large corporations tax	**28**	30	31
Lower effective tax rate on equity in earnings of affiliates	**(11)**	(2)	(1)
Other	**(21)**	(8)	(1)
Actual income tax expense	**535**	517	480

Future Income Tax Assets and Liabilities

December 31 (millions of dollars)	2003	2002
Net operating and capital loss carryforwards	**28**	91
Deferred costs	**50**	49
Deferred revenue	**29**	55
Alternative minimum tax credits	**29**	31
Other	**24**	41
	160	267
Less: Valuation allowance	**24**	33
Future income tax assets, net of valuation allowance	**136**	234
Difference in accounting and tax bases of plant, equipment and PPAs	**396**	345
Investments in subsidiaries and partnerships	**108**	107
Other	**59**	8
Future income tax liabilities	**563**	460
Net future income tax liabilities	**427**	226

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 $1,758 million at December 31, 2003 (2002 – $1,702 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 intends to indefinitely reinvest in foreign operations. If provision for these taxes had been made, future income tax liabilities would increase by approximately $54 million at December 31, 2003 (2002 – $60 million).

Income Tax Payments Income tax payments of $220 million were made during the year ended December 31, 2003 (2002 – $257 million; 2001 – $292 million).

Note 13 NOTES PAYABLE

	2003		2002	
	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	**367**	**2.7%**	258	2.9%
U.S. dollars	**–**		39	1.4%
	367		297	

Total credit facilities of $2.2 billion at December 31, 2003, were available to support the Company's commercial paper programs and for general corporate purposes. Of this total, $1.9 billion represents committed credit facilities of which $1.5 billion represents a syndicated facility established in December 2002. This facility is comprised of a $1.0 billion tranche with a three 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 2003, the $1.0 billion tranche to December 2006 and the $500 million tranche to December 2004. The remaining committed facilities are non extendible, $60 million expires in June 2004 and $320 million expires in June 2005.

At December 31, 2003, the Company had used approximately $217 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, 2003 (2002 – $1 million).

Note 14 EMPLOYEE FUTURE BENEFITS

The Company sponsors defined benefit pension plans (DB Plans) that cover substantially all employees and sponsored a defined contribution pension plan (DC Plan) which was effectively terminated at December 31, 2002. The DB Plans are based on years of service and highest average earnings over three consecutive years of employment. 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 an average of 12 years.

The Company also provides its employees with other post-employment benefits other than pensions, including special 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 is nil for the year ended December 31, 2003 (2002 – $6 million; 2001 – $7 million). In 2003, the Company also expensed $1 million (2002 – nil; 2001 – nil) related to retirement savings plans for its U.S. employees.

Information about the Company's DB Plans measured and valued at December 31 is as follows.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2003**	2002	**2003**	2002
Change in Benefit Obligation				
Benefit obligation – beginning of year	**841**	659	**95**	60
Current service cost	**25**	11	**2**	2
Interest cost	**52**	43	**6**	4
Employee contributions	**2**	1	**–**	–
Benefits paid	**(45)**	(58)	**(4)**	(4)
Actuarial loss	**66**	93	**7**	26
Acquisition of subsidiary	**19**	–	**–**	–
Plan amendment	**–**	92	**–**	7
Benefit obligation – end of year	**960**	841	**106**	95
Change in Plan Assets				
Plan assets at fair value – beginning of year	**621**	573	**–**	–
Actual return on plan assets	**89**	9	**–**	–
Employer contributions	**110**	48	**4**	4
Employee contributions	**2**	1	–	–
Benefits paid	**(45)**	(58)	**(4)**	(4)
Acquisition of subsidiary	**22**	–	**–**	–
Assets receivable from DC Plan	**–**	48	**–**	–
Plan assets at fair value – end of year	**799**	621	**–**	–
Funded status – plan deficit	**(161)**	(220)	**(106)**	(95)
Unamortized net actuarial loss	**263**	246	**39**	33
Unamortized past service costs	**41**	44	**6**	7
Unamortized transitional obligation related to regulated business	**–**	–	**25**	27
Accrued benefit asset/(liability), net of valuation allowance of nil (1)	**143**	70	**(36)**	(28)

(1) Assets and liabilities are included in Other Assets and Deferred Amounts, respectively, in TransCanada's Consolidated Balance Sheet.

The Company's expected contributions for the year 2004 are approximately $80 million for the pension benefit plans and approximately $5 million for the other benefit plans.

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	
	2003	2002	**2003**	2002
Discount rate	**6.00%**	6.25%	**6.25%**	6.50%
Rate of compensation increase	**3.50%**	3.75%		

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

	Pension Benefit Plans			Other Benefit Plans		
	2003	2002	2001	**2003**	2002	2001
Discount rate	**6.25%**	6.75%	6.80%	**6.50%**	6.85%	6.90%
Expected long-term rate of return on plan assets	**7.25%**	7.52%	7.10%			
Rate of compensation increase	**3.75%**	3.50%	3.50%			

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for both the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and future expectations of the level and volatility of returns. Asset class benchmark returns, asset mix and anticipated benefit payments from plan assets are also considered in the determination of the overall expected rate of return.

For measurement purposes, a 7.5 per cent annual rate of increase in the per capita cost of covered health care benefits was assumed for 2004. The rate was assumed to decrease gradually to 5.0 per cent for 2009 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	1	(1)
Effect on post-employment benefit obligation	11	(10)

The Company's net benefit plan expense is as follows.

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31 (millions of dollars)	**2003**	2002	2001	**2003**	2002	2001
Current service cost	**25**	11	12	**2**	2	2
Interest cost	**52**	43	41	**6**	4	4
Expected return on plan assets	**(51)**	(45)	(41)	**–**	–	–
Amortization of transitional obligation related to regulated business	**–**	–	–	**2**	2	2
Amortization of net actuarial loss	**8**	2	–	**1**	–	–
Amortization of past service costs	**3**	–	–	**1**	–	–
	37	11	12	**12**	8	8
Net benefit cost recognized – discontinued operations	**–**	–	2	**–**	–	–
Net benefit cost recognized – continuing operations	**37**	11	10	**12**	8	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	**2003**	2002	**2003**
Debt securities	**47%**	51%	**35% to 60%**
Equity securities	**53%**	49%	**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 15 CHANGES IN OPERATING WORKING CAPITAL

Year ended December 31 (millions of dollars)	**2003**	2002	2001
Decrease/(increase) in accounts receivable	**26**	(45)	38
Decrease/(increase) in inventories	**15**	(3)	52
Decrease/(increase) in other current assets	**21**	(53)	(12)
Increase in accounts payable	**52**	120	105
(Decrease)/increase in accrued interest	**(2)**	14	(13)
	112	33	170

Note 16 COMMITMENTS, CONTINGENCIES AND GUARANTEES

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

Year ended December 31 (millions of dollars)	Minimum Lease Payments	Amounts Recoverable under Sub-Leases	Net Payments
2004	25	(7)	18
2005	25	(7)	18
2006	25	(7)	18
2007	24	(7)	17
2008	24	(7)	17

The operating lease agreements expire at various dates through 2011, with an option to renew certain lease agreements for five years.

At December 31, 2003, TransCanada held a 35.6 per cent interest in TransCanada Power, L.P. which is a publicly-held limited partnership. On June 30, 2017, the partnership will redeem all units outstanding, not held directly or indirectly by TransCanada, at their then fair market value, being the average of the fair market values assigned thereto by independent valuators, plus all declared and unpaid distributions of distributable cash thereon (the Redemption Price). TransCanada is required to fund the Redemption Price in accordance with the terms of the Power LP Partnership agreement.

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 then connect with the Alberta System. Under the agreement, TransCanada has agreed to finance the APG for its one-third share of project definition phase costs. This share is estimated to be approximately $90 million over three years. In the year ended December 31, 2003, TransCanada funded $34 million of this loan which is included in Other Assets. The ability to recover this investment is contingent upon the outcome of the project.

Contingencies The Canadian Alliance of Pipeline Landowners' Associations and two individual landowners have commenced an action under Ontario's Class Proceedings Act, 1992, against TransCanada and Enbridge Inc. for damages 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, 2003 was estimated to be approximately $215 million. The terms of the guarantees range from 2004 to 2018. The current carrying amount of the liability related to these guarantees is nil and the fair value is approximately $4 million.

TransCanada has guaranteed the equity undertaking of a subsidiary which supports the payment, under certain conditions, of principal and interest on the US$195 million 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.

Note 17 DISCONTINUED OPERATIONS

The Board of Directors approved plans to dispose of the Company's International, Canadian Midstream, and certain other businesses (December Plan) and the Gas Marketing business in December 1999 and July 2001, respectively. The Company's disposals under both plans were substantially completed at December 31, 2001.

TransCanada's investments in Gasoducto del Pacifico, INNERGY Holdings S.A. and P.T. Paiton Energy Company approved for disposal under the December Plan will be accounted for as part of continuing operations as of December 31, 2003, due to the length of time it has taken the Company to dispose of these assets. It is the intention of the Company to continue with its plan to dispose of these investments.

The Company mitigated certain of its remaining exposures associated with the contingent liabilities related to the divested Gas Marketing operations by acquiring from a subsidiary of Mirant Corporation (Mirant) certain contracts under which it still had exposure in 2003, and simultaneously hedging the market price exposures of these contracts. The Company remains contingently liable for certain residual obligations. In 2003, $50 million of the original approximately $100 million after-tax deferred gain was recognized in income. The remaining after-tax deferred gain is included in Deferred Amounts.

At December 31, 2003, TransCanada reviewed the provision for loss on discontinued operations and the deferred gain and concluded that the remaining provision was adequate and the deferral of the remaining approximately $50 million of after-tax deferred gain related to the Gas Marketing business was appropriate.

Revenues from discontinued operations for the year ended December 31, 2003 were $2 million (2002 – $36 million; 2001 – $12,895 million). Net income/(loss) from discontinued operations for the year ended December 31, 2003 was $50 million, net of $29 million income taxes (2002 – nil; 2001 – $(67) million, net of $(33) million income taxes). The provision for loss on discontinued operations at December 31, 2003 was $41 million (2002 – $83 million). The provision for loss on discontinued operations is included in Accounts Payable.

Note 18 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)	**2003**	2002	2001
Revenues (2)	**4,919**	4,565	4,165
Cost of sales (2)	**592**	441	47
Other costs and expenses	**1,663**	1,532	1,609
Depreciation	**819**	729	675
	3,074	2,702	2,331
Operating income	**1,845**	1,863	1,834
Other (income)/expenses			
Equity income (1) (3)	**(334)**	(260)	(221)
Other expenses (4) (5)	**863**	872	953
Income taxes	**515**	499	407
	1,044	1,111	1,139
Income from continuing operations – U.S. GAAP	**801**	752	695
Net income/(loss) from discontinued operations – U.S. GAAP	**50**	–	(67)
Income before cumulative effect of the application of accounting changes in accordance with U.S. GAAP	**851**	752	628
Cumulative effect of the application of accounting changes, net of tax (2) (4)	**(13)**	–	(2)
Net income in accordance with U.S. GAAP	**838**	752	626
Adjustments affecting comprehensive income under U.S. GAAP			
Foreign currency translation adjustment, net of tax (6)	**(54)**	1	–
Additional minimum liability for employee future benefits, net of tax (7)	**(2)**	(40)	(56)
Unrealized gain/(loss) on derivatives, net of tax (4)	**8**	(4)	(5)
Comprehensive income before cumulative effect of the application of accounting changes in accordance with U.S. GAAP	**790**	709	565
Cumulative effect of the application of accounting changes, net of tax (4)	**–**	–	(4)
Comprehensive income in accordance with U.S. GAAP	**790**	709	561
Net income/(loss) per share in accordance with U.S. GAAP			
Continuing operations	**$1.67**	$1.57	$1.46
Discontinued operations	**0.10**	–	(0.14)
Income before cumulative effect of the application of accounting changes in accordance with U.S. GAAP	**$1.77**	$1.57	$1.32
Cumulative effect of the application of accounting changes, net of tax (2) (4)	**(0.03)**	–	–
Basic	**$1.74**	$1.57	$1.32
Diluted	**$1.73**	$1.56	$1.32
Net income per share in accordance with Canadian GAAP			
Basic	**$1.76**	$1.56	$1.30
Diluted	**$1.76**	$1.55	$1.30
Dividends per common share	**$1.08**	$1.00	$0.90

Reconciliation of Income from Continuing Operations

Year ended December 31 (millions of dollars)	**2003**	2002	2001
Net income from continuing operations in accordance with Canadian GAAP	**801**	747	686
U.S. GAAP adjustments			
Unrealized (loss)/gain on foreign exchange and interest rate derivatives (4)	**(9)**	30	(14)
Tax impact of (loss)/gain on foreign exchange and interest rate derivatives	**3**	(12)	6
Unrealized gain/(loss) on energy trading contracts (2)	**28**	(21)	(17)
Tax impact of unrealized gain/(loss) on energy trading contracts	**(10)**	8	6
Equity loss (3)	**(18)**	–	–
Tax impact of equity loss	**6**	–	–
Income taxes from substantively enacted tax rates (8)	**–**	–	28
Income from continuing operations in accordance with U.S. GAAP	**801**	752	695

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

December 31 (millions of dollars)	**2003**	2002
Current assets	**1,020**	1,079
Long-term energy trading assets (2)	**–**	218
Long-term investments (3) (9)	**1,760**	1,683
Plant, property and equipment (10)	**15,798**	14,992
Regulatory asset (11)	**2,721**	2,578
Other assets (4)	**1,192**	884
	22,491	21,434
Current liabilities (12)	**2,073**	2,006
Long-term energy trading liabilities (2)	**–**	41
Deferred amounts (2) (4) (9) (10)	**741**	789
Long-term debt (4)	**9,494**	8,963
Deferred income taxes (11)	**3,039**	2,692
Preferred securities (13)	**694**	694
Trust originated preferred securities	**–**	218
Non-controlling interests	**471**	389
Shareholders' equity	**5,979**	5,642
	22,491	21,434

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, 2001	13	–	–	13
Additional minimum liability for employee future benefits, net of tax of $30 (7)	–	(56)	–	(56)
Unrealized loss on derivatives, net of tax of $2 (4)	–	–	(5)	(5)
Cumulative effect of the application of accounting changes, net of tax of $3 (4)	–	–	(4)	(4)
Balance at December 31, 2001	13	(56)	(9)	(52)
Additional minimum liability for employee future benefits, net of tax of $22 (7)	–	(40)	–	(40)
Unrealized loss on derivatives, net of tax of $(1) (4)	–	–	(4)	(4)
Foreign currency translation adjustment, net of tax of nil (6)	1	–	–	1
Balance at December 31, 2002	14	(96)	(13)	(95)
Additional minimum liability for employee future benefits, net of tax of $1 (7)	**–**	**(2)**	**–**	**(2)**
Unrealized gain on derivatives, net of tax of nil (4)	**–**	**–**	**8**	**8**
Foreign currency translation adjustment, net of tax of $(64) (6)	**(54)**	**–**	**–**	**(54)**
Balance at December 31, 2003	**(40)**	**(98)**	**(5)**	**(143)**

(1) In accordance with U.S. GAAP, the Condensed Statement of Consolidated Income and Condensed 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) In 2002, for U.S. GAAP purposes, TransCanada adopted the transitional provisions of FASB Emerging Issues Task Force (EITF) 02-3, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" whereby the Company was netting all revenues and expenses related to derivative energy trading contracts. The accounting change was applied retroactively with reclassification of prior periods. Prior to adoption of EITF 02-3, energy trading contracts were measured at fair value determined as at the balance sheet date. Effective January 1, 2003, the Company fully adopted EITF 02-3. This accounting change was effected through a cumulative adjustment of $(13) million, after tax, in the current year's income with no restatement of prior periods. Substantially all of the energy trading contracts are accounted for as hedges under Canadian GAAP. Subsequent to October 1, 2003, the energy trading contracts that qualified as hedges were accounted for as hedges under the provisions of Statement of Financial Accounting Standards (SFAS) No. 133. All gains or losses on the contracts that did not qualify as hedges, and the amounts of any ineffectiveness on the hedging contracts, are included in income each period. Substantially all of the amounts recorded in 2003 as differences between U.S. and Canadian GAAP relate to gains and losses on contracts that were not accounted for as hedges.

(3) (a) 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 are required to be expensed under U.S. GAAP.

(b) 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, 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.

(4) In 2001, the Company adopted the provisions of SFAS No. 133 "Accounting for Derivatives and Hedging Activities". SFAS No. 133 requires that all derivatives be 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.

On initial adoption of SFAS No. 133 on January 1, 2001, additional assets of $93 million and liabilities of $99 million were recorded for U.S. GAAP purposes to reflect the fair value of derivatives designated as interest rate hedges and the corresponding change in the fair value of items designated as hedges. A charge of $2 million, after tax, relating to the fair value of hedges was recognized in income and $4 million, after tax, relating to the fair value of derivatives designated as cash flow hedges was recognized in other comprehensive income as the cumulative effect of application of SFAS No. 133.

During 2003, net gains of $47 million (2002 – $38 million; 2001 – $36 million) from the hedges of changes in the fair value of long-term debt, and net losses of $53 million (2002 – $20 million; 2001 – $44 million) in the fair value of the hedged item were included in earnings 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 2003, 2002 and 2001 with respect to ineffectiveness of cash flow hedges. For amounts included in other comprehensive income at December 31, 2003, $9 million (2002 – $(5) million; 2001 – $(3) million) relates to the hedge of interest rate risk, $5 million (2002 – $1 million; 2001 – $(2) million) relates to the hedge of foreign exchange rate risk, and $(6) million (2002 – nil; 2001 – nil) relates to the hedge of energy price risk. Of these amounts, $(5) million is expected to be recorded in earnings during 2004.

At December 31, 2003, additional assets of $107 million (2002 – $198 million) and additional liabilities of $110 million (2002 – $203 million) were recorded for U.S. GAAP purposes to reflect the fair value of derivatives designated as hedges and the corresponding change in the fair value of items designated as hedges.

(5) Other expenses include an allowance for funds used during construction of $2 million for the year ended December 31, 2003 (2002 – $4 million; 2001 – $5 million).

(6) Under U.S. GAAP, changes in the foreign currency translation adjustment account must be recorded as a component of comprehensive income.

(7) 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)	**2003**	2002
Prepaid benefit cost	**$ 143**	$ 70
Accrued benefit cost	**–**	–
Intangible assets	**(41)**	(44)
Accumulated other comprehensive income	**(151)**	(148)
Net amount recognized	**$ (49)**	$ (122)

The accumulated benefit obligation for the Company's DB Plans was $819 million at December 31, 2003 (2002 – $738 million).

(8) Under U.S. GAAP, only enacted rates can be used in measuring deferred tax assets and liabilities; use of substantively enacted rates is not permitted. The February 2000 and October 2000 Federal budgets would not be considered enacted until the proposals were completely enacted into law in June 2001 and, accordingly, the related tax recoveries were recognized in 2001.

(9) 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, the Company has recorded the fair value of the guarantees ($4 million) arising on the acquisition of the interest in Bruce Power as a liability and an increase in the cost of the investment.

(10) Effective January 1, 2003, the Company adopted the provisions of SFAS No. 143 "Accounting for Asset Retirement Obligations", which addresses financial accounting and reporting for obligations associated with asset retirement costs. SFAS No. 143 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.

The plant, property and equipment of the regulated natural gas transmission operations consist 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 that all retirement costs associated with the regulated pipelines will be recovered through tolls in future periods.

The plant, property and equipment in the power business consists primarily of power plants in Canada and the United States. The estimated fair value of the liability for the power plants and associated assets as at January 1, 2003 was $6 million. 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 estimated fair value of the liability as at December 31, 2003 was $7 million. The cumulative effect of the application of SFAS No. 143 on income with respect to the years ended December 31, 2001 and 2002 would have been less than $1 million. The Company has no legal liability for asset retirement obligations with respect to its investment in Bruce Power and the Sundance A and B power purchase arrangements.

(11) 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.

(12) Current liabilities at December 31, 2003 include dividends payable of $136 million (2002 – $125 million) and current taxes payable of $271 million (2002 – $150 million).

(13) The fair value of the preferred securities at December 31, 2003 was $612 million (2002 – $743 million). The Company made preferred securities charges payments of $57 million for the year ended December 31, 2003 (2002 – $58 million; 2001 – $77 million).

(14) The Company's Statement of Consolidated Cash Flows under U.S. GAAP would be identical to that under Canadian GAAP except that the preferred securities charges would be classified with funds generated from continuing operations.

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)	**2003**	2002
Deferred Tax Liabilities		
Difference in accounting and tax bases of plant, equipment and PPAs	**1,813**	1,703
Taxes on future revenue requirement	**962**	876
Investments in subsidiaries and partnerships	**373**	379
Other	**87**	22
	3,235	2,980
Deferred Tax Assets		
Net operating and capital loss carry forwards	**28**	91
Deferred amounts	**79**	104
Other	**113**	126
	220	321
Less: Valuation allowance	**24**	33
	196	288
Net deferred tax liabilities	**3,039**	2,692

Stock-Based Compensation Under the transition rules provided by SFAS No. 148 "Accounting for Stock-Based Compensation – Transition and Disclosure – an amendment of FASB Statement No. 123", the Company is expensing stock options granted in 2003 and 2002. The use of the fair value method of SFAS No. 123 "Accounting for Stock-Based Compensation" for previously issued options would have resulted in net income under U.S. GAAP of $836 million in 2003 (2002 – $749 million; 2001 – $621 million) and net income per share (basic) of $1.74 in 2003 (2002 – $1.56 per share; 2001 – $1.30 per share).

Other In 2003, the FASB issued 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"). Variable interests are the rights or obligations that convey economic gains or losses from changes in the values of an entity's assets or liabilities. The holder of the majority of an entity's variable interests will be required to consolidate the variable interest entity. Adopting the provisions of FIN 46 (Revised) 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. Effective January 1, 2005, in accordance with Canadian GAAP, certain instruments that are currently classified as equity will be classified as liabilities, under new Canadian accounting standards.

Summarized Financial Information of Long-Term Investments (15)

Year ended December 31 (millions of dollars)	2003	2002	2001
Income			
Revenues	**1,063**	798	695
Other costs and expenses	**(528)**	(273)	(191)
Depreciation	**(141)**	(146)	(143)
Financial charges and other	**(53)**	(112)	(136)
Proportionate share of income before income taxes of long-term investments	**341**	267	225

December 31 (millions of dollars)	2003	2002
Balance Sheet		
Current assets	**385**	246
Plant, property and equipment	**2,944**	3,251
Other assets (net)	**–**	112
Current liabilities	**(204)**	(216)
Deferred amounts (net)	**(286)**	–
Non-recourse debt	**(1,060)**	(1,646)
Deferred income taxes	**(19)**	(64)
Proportionate share of net assets of long-term investments	**1,760**	1,683

(15) This 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).