2002 **ANNUAL REPORT**

pipe power people

PERFORMANCE

TransCanada

In business to deliver™

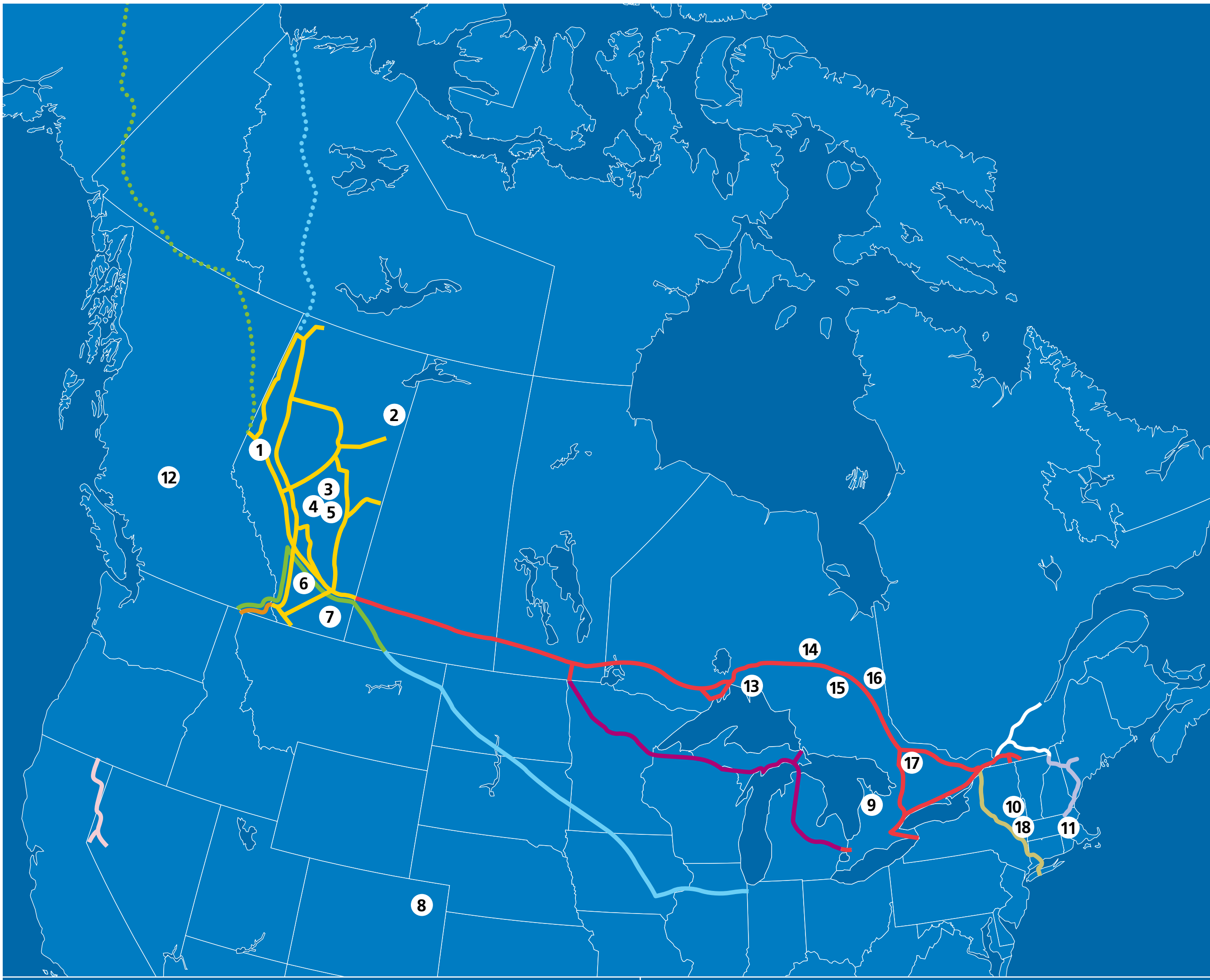
pipe

power

Backed by $20 billion of premium assets, TransCanada is a leading North American energy company focused on natural gas transmission and power generation. The skills and expertise of our people and our strong financial position provide us with a clear advantage in a highly competitive environment.

Our 38,000 kilometre (24,000 mile) natural gas pipeline system is one of the largest and most sophisticated in the world. It links the rich natural gas resources of the Western Canada Sedimentary Basin to markets across Canada and the United States. We are well positioned to play a key role in bringing northern gas to the growing North American marketplace.

A rapidly emerging player in the North American power industry, we have interests in a growing portfolio of assets capable of producing more than 4,000 megawatts of power. Our plants utilize a diverse range of fuels and are among the most efficient on the continent. We also market electricity across Canada and the northern United States to meet the needs of a wide range of industrial clients.



NATURAL GAS TRANSMISSION

- Alberta System
- Canadian Mainline
- BC System
- Foothills Pipe Lines (50 – 74.5%)
- Great Lakes Gas Transmission Limited Partnership (50%)
- Trans Québec & Maritimes Pipeline Inc. (50%)
- Iroquois Gas Transmission System (40.96%)
- Portland Natural Gas Transmission System (33.29%)
- Northern Border Pipeline Company (10% indirectly through TC PipeLines, LP)
- Tuscarora Gas Transmission Company (1% directly; 16.4% indirectly through TC PipeLines, LP)
- Mackenzie Valley Extension (proposed by producers)
- Alaska Highway Pipeline (proposed by Foothills Pipe Lines)

POWER GENERATION

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

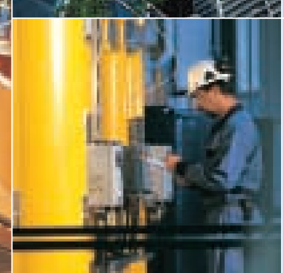
TransCanada Power, L.P. (35.6%)

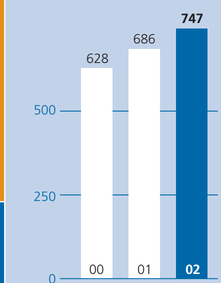
12. Williams Lake
13. Nipigon
14. Calstock
15. Kapuskasing
16. Tunis
17. North Bay
18. Castleton

Ownership 100% unless otherwise specified.

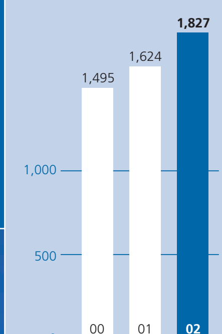
STRATEGIES FOR GROWTH AND VALUE CREATION

• SUSTAIN, GROW AND OPTIMIZE OUR NORTH AMERICAN NATURAL GAS TRANSMISSION BUSINESS • ESTABLISH A NEW REGULATED BUSINESS MODEL • GROW OUR POWER BUSINESS • PURSUE OPERATIONAL EXCELLENCE • MAINTAIN AND UTILIZE OUR STRONG FINANCIAL POSITION

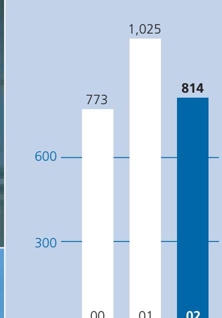




NET INCOME APPLICABLE TO COMMON SHARES FROM CONTINUING OPERATIONS
(millions of dollars)



FUNDS GENERATED FROM CONTINUING OPERATIONS
(millions of dollars)



CAPITAL EXPENDITURES AND ACQUISITIONS IN CONTINUING OPERATIONS
(millions of dollars)

FINANCIAL HIGHLIGHTS

IN 2002, TRANSCANADA DELIVERED ON ITS COMMITMENT TO MAXIMIZE SHAREHOLDER VALUE. TOTAL SHAREHOLDER RETURN, INCLUDING DIVIDENDS, WAS 21 PER CENT.

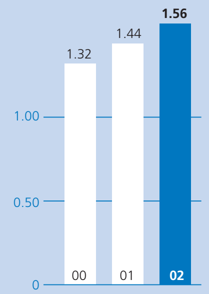
We continued to make profitable investments in our core businesses, pay down debt and reduce operating costs. Our actions resulted in an increase in earnings and cash flow and a stronger balance sheet. In January 2003, TransCanada's Board of Directors raised the quarterly dividend on the company's common shares from $0.25 per share to $0.27 per share, for the quarter ended March 31, 2003.

OPERATING RESULTS

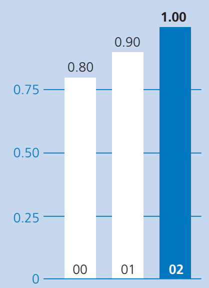
Year ended December 31	**2002**	2001	2000
(millions of dollars)			
Income Statement			
Net income/(loss) applicable to common shares			
Continuing operations	**747**	686	628
Discontinued operations	**–**	(67)	61
	747	619	689
Cash Flow Statement			
Funds generated from continuing operations	**1,827**	1,624	1,495
Capital expenditures and acquisitions in continuing operations	**814**	1,025	773
Balance Sheet			
Total assets	**19,916**	19,954	24,817
Long-term debt	**8,815**	9,347	9,928
Common shareholders' equity	**5,747**	5,426	5,211

COMMON SHARE STATISTICS

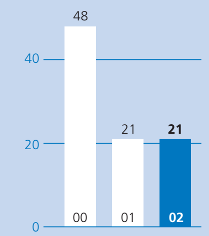
Year ended December 31	**2002**	2001	2000
Net income/(loss) per share – basic			
Continuing operations	**$ 1.56**	$ 1.44	$ 1.32
Discontinued operations	**–**	(0.14)	0.13
	$ 1.56	$ 1.30	$ 1.45
Net income per share – diluted	**$ 1.55**	$ 1.30	$ 1.45
Dividends declared per share	**$ 1.00**	$ 0.90	$ 0.80
Common shares outstanding *(millions)*			
Average for the year	**478.3**	475.8	474.6
End of year	**479.5**	476.6	474.9



NET INCOME PER COMMON SHARE FROM CONTINUING OPERATIONS – BASIC
(dollars)



DIVIDENDS DECLARED PER COMMON SHARE
(dollars)



TOTAL SHAREHOLDER RETURN
(per cent)

CHAIRMAN'S MESSAGE

2002 WAS A YEAR IN WHICH CORPORATE GOVERNANCE ROSE TO NEW PROMINENCE IN THE EYES OF INVESTORS.

We are pleased to see governance recognized as a significant factor in determining a company's success. However, we are disappointed that the actions of a highly visible few have resulted in widespread distrust of our corporate leaders and a belief that ethics and integrity must be enforced.

TransCanada takes this issue very seriously. We are proud to have been recognized for our leadership in corporate governance. The Board and management have long been committed to achieving the highest standards of business ethics and governance, consistently meeting, and exceeding, the Toronto Stock Exchange's Guidelines for Corporate Governance. Further, TransCanada already meets most of the new requirements of the Sarbanes-Oxley Act and the proposed stock exchange guidelines.

At TransCanada, we are genuinely motivated by the desire to do the right thing in the interests of our shareholders. We are gratified that our commitment to sound ethical practices contributes directly to enhancing TransCanada's reputation, and ultimately, its value to shareholders. By setting a high standard of honesty, fairness and integrity, TransCanada, along with its peers, hopes to restore respect for the business community.

The management and employees of TransCanada are deserving of our recognition for their commitment to living TransCanada's values and for their work in delivering strong financial and operating performance. In January 2003, on the strength and sustainability of TransCanada's earnings in 2002, the Board was able to raise the dividend for the third consecutive year. We applaud your efforts and thank you for your continued commitment to TransCanada.

I thank my fellow Directors for their hard work and ongoing dedication to TransCanada. Ron Coleman will be retiring from the Board at our shareholder meeting in 2003. He has served with distinction for many years on the boards of NOVA Corporation and TransCanada and we thank him for his valuable contribution. We also welcome Barry Jackson, Chairman of Resolute Energy Inc. and Deer Creek Energy Limited, and a Director of Nexen Inc., who was appointed to the Board in December 2002.

On behalf of the Board of Directors,

Richard F. Haskayne
Chairman

IN 2002, TRANSCANADA MAINTAINED ITS LEADERSHIP POSITION IN THE NORTH AMERICAN NATURAL GAS TRANSMISSION BUSINESS AND CONTINUED ITS DISCIPLINED, VALUE-CREATING GROWTH IN POWER.

TransCanada delivered another year of strong financial performance with increases in earnings and operating cash flow. We continued to strengthen our balance sheet and liquidity position. In January 2003, TransCanada's Board of Directors raised the dividend on common shares for the third consecutive year. The quarterly dividend was increased by eight per cent to $0.27 per share for the quarter ending March 31, 2003.

We accomplished this against a backdrop of challenge and change within the North American energy industry. Our achievements are testament to the dedication and commitment of the people of TransCanada. Our expertise, experience and disciplined approach to value creation make TransCanada the strongest team in the business and I'm proud to be part of that team. I thank all employees for their contributions to our continuing success.

STRATEGY AND FOCUS

Our achievements are clear evidence that the strategic direction we established in 2000 is working exceptionally well. While we have refined our key strategies to keep pace with developments in the rapidly changing external environment, the five core components have remained consistent.

1. Sustain, Grow and Optimize Our North American Natural Gas Transmission Business

In 2002, we substantially completed the Westpath expansion project on the Alberta and BC systems to serve growing markets in California and the Pacific Northwest. This project marked the first field installation and testing of X100 steel line pipe – the highest strength large diameter line pipe in use worldwide. Throughout the year, we continued our efforts to optimize all aspects of our wholly-owned pipelines, which together comprise the largest single natural gas transmission system in North America.

We also acquired a general partnership interest in Northern Border Partners, L.P., which owns a 70 per cent interest in Northern Border Pipeline Company. We consider Northern Border to be one of the preferred routes to move gas from the Northern frontier to midwestern markets.

TOTAL SHAREHOLDER RETURN

including dividends, was 21 per cent in each of the last two years and 48 per cent in 2000.

OUR STRENGTHS

are our premium assets, the experience and expertise of our people and our strong financial position.

OUR GOAL

is to be one of the most profitable, competitive, reliable providers of wholesale natural gas transportation and electric power in North America.

OUR PIPELINE BUSINESS

is focused on developing the infrastructure required to link future supply sources with growing demand.

The projected growth of North American natural gas demand, combined with the potential to acquire significant assets as competitors seek to restore their balance sheets, create attractive opportunities for TransCanada.

On the supply side, growth is expected from a number of traditional sources including the Western Canada Sedimentary Basin (WCSB) and the Gulf Coast. However, even optimistic assessments of future supply from these basins will not meet the anticipated growth in demand. We strongly believe northern gas and offshore liquefied natural gas will be required by the end of the decade.

In the near term, our emphasis will be on connecting new supply from the WCSB to our Alberta System. We will also expand and extend our long-haul delivery systems as appropriate and look to increase our ownership in partially-owned pipeline systems.

Over the long term we will move forward on northern development. We will also seek opportunities to work closely with producers and regional stakeholders to build the facilities necessary for the importation of liquefied natural gas.

TransCanada supports the development of both the Mackenzie Valley and Alaska Highway pipelines. At this point in time, we expect the Mackenzie Valley pipeline to be the first to proceed. Our high capacity connections from the WCSB to premier North American markets will enable us to move northern gas when the time is right. Our many years of experience in constructing and operating large diameter natural gas pipeline systems in cold weather, combined with our solid reputation for safety and reliability, are significant competitive advantages.

2. Establish a New Regulated Business Model

On the regulatory front, 2002 proved to be a challenging year. The National Energy Board's (NEB) decision on the Canadian Mainline Fair Return application – and its subsequent denial of TransCanada's request to review this decision – was disappointing. In our view, the ruling does not recognize the long-term business risks of the Canadian Mainline.

In February 2003, we reached a one-year settlement regarding the 2003 revenue requirement for the Alberta System. The settlement, which was the result of a consultative process that included producers, industrial users, consumer groups, marketers, and export groups, was significantly influenced by the NEB decision on the Fair Return application.

The issues TransCanada and our stakeholders face are difficult to address within a single negotiated settlement or regulatory proceeding. However, we have established a new level of dialogue with our customers and we remain optimistic that future negotiations will lead to acceptable outcomes for both TransCanada and our customers. Our goal is to establish a framework that provides flexible, cost-competitive services and allows us to earn a fair risk-adjusted return.

3. Grow Our Power Business

In a year of downturn for the power industry, TransCanada's power business produced solid results. In 2002:

- We started operations at the Redwater and Carseland power facilities and continued construction of the Bear Creek and MacKay River power plants in Alberta
- We acquired the ManChief power plant, a 300 megawatt facility in Colorado, and
- We announced our acquisition of a 31.6 per cent interest in Bruce Power L.P., the tenant under a lease on the Bruce nuclear power facility in Ontario. This acquisition was completed in mid-February 2003.

The current state of the power industry provides both opportunities and challenges for TransCanada. While the pace of plant construction in North America has slowed, we anticipate a number of quality acquisition opportunities in the coming year, together with niche development opportunities where we can leverage our expertise in cogeneration. We will grow our power portfolio by focusing on low-risk opportunities in markets we know. We will apply business models that benefit from, and support, our strong balance sheet. We will use power marketing to optimize the value of our assets and create stable and predictable income and cash flow.

OUR POWER PORTFOLIO now includes interests in more than 4,000 megawatts of generating capacity located in some of the best markets in North America.

4. Pursue Operational Excellence

Over the last three years we have achieved significant and sustainable operating cost savings, which, over the longer term, largely accrue to the benefit of our customers. We have also improved the quality and timeliness of customer service. Our objectives are to:

- Be the most efficient operator of North American pipe and power assets
- Provide the right services at the lowest possible cost
- Invest our capital in the right things at the right time, and
- Be responsive to our customers.

We relentlessly pursue our commitment to an operational excellence business model, recognizing that our customers count on us to deliver gas and generate power in a low-cost, safe and reliable manner.

TRANSCANADA STRIVES to deliver a combination of quality, price and ease of doing business that no peer can match.

5. Maintain and Utilize Our Strong Financial Position

TransCanada's financial position strengthened during 2002. Today, our balance sheet is stronger than it has been in the past 15 years. Over the last three years, our strong cash flow, together with the proceeds from the sale of non-core assets have allowed us to:

- Invest more than $2.5 billion in our core businesses, and
- Retire more than $4 billion in term debt and preferred securities.

We expect to generate substantial operating cash flow in 2003 and beyond. Our strong discretionary cash position means we are well positioned for growth and value creation.

LOOKING AHEAD

WE ARE FOCUSED

on disciplined management and growth of our natural gas transmission and power businesses.

In 2003, we will maintain our focus on our core strategies with an emphasis on well planned, well executed growth that creates value for our shareholders without compromising our financial strength.

TransCanada is poised to capture opportunities and create value in a business environment that has challenged many of our competitors. We are driven by shareholder value rather than the size of our asset base – we measure success in terms of profitability, value creation and long-term sustainability.

TransCanada has been participating in North American energy markets for more than 50 years – we're in this for the long haul. We'll keep this firmly in mind as we evaluate the opportunities and deal with the challenges of 2003.

Harold N. Kvisle
President and Chief Executive Officer

February 25, 2003

Management's Discussion and Analysis should be read in conjunction with the audited Consolidated Financial Statements of TransCanada PipeLines Limited (TransCanada or the company) and the notes thereto for the year ended December 31, 2002.

Consolidated Financial Review

HIGHLIGHTS

Earnings Increase TransCanada's net income applicable to common shares from continuing operations (net earnings) increased $61 million or nine per cent to $747 million or $1.56 per share in 2002 compared to $686 million or $1.44 per share in 2001.

Funds Flow Increase Funds generated from continuing operations increased $203 million or 13 per cent to $1.8 billion in 2002 compared to $1.6 billion in 2001.

Balance Sheet Strengthened In 2002, TransCanada continued to strengthen its balance sheet as it repaid debt maturities of $486 million, reduced notes payable by $46 million and increased shareholders' equity by $320 million.

Dividend Increase On January 28, 2003, the Board of Directors of TransCanada raised the quarterly dividend on the company's outstanding common shares eight per cent from $0.25 per share to $0.27 per share for the quarter ending March 31, 2003.

Growth in Core Businesses In 2002, TransCanada invested more than $800 million in its gas transmission and power businesses from internally generated cash flow.

CONSOLIDATED RESULTS-AT-A-GLANCE

Year ended December 31	2002	2001	2000
(millions of dollars except per share amounts)			
Net Income/(Loss) Applicable to Common Shares			
Continuing operations	**747**	686	628
Discontinued operations	–	(67)	61
	747	619	689
Net Income/(Loss) Per Share – Basic			
Continuing operations	**$ 1.56**	$ 1.44	$ 1.32
Discontinued operations	–	(0.14)	0.13
	$ 1.56	$ 1.30	$ 1.45

SEGMENT RESULTS-AT-A-GLANCE

Year ended December 31	2002	2001	2000
(millions of dollars)			
Transmission	**653**	585	623
Power	**146**	168	85
Corporate	**(52)**	(67)	(80)
Continuing operations	**747**	686	628
Discontinued operations	**–**	(67)	61
Net Income Applicable to Common Shares	**747**	619	689

Net income applicable to common shares for the year ended December 31, 2002, was $747 million or $1.56 per share. This compares to net income of $619 million or $1.30 per share in 2001 which included a net loss from discontinued operations of $67 million or $0.14 per share, and net income of $689 million or $1.45 per share in 2000, which included net income from discontinued operations of $61 million or $0.13 per share.

TransCanada's net income applicable to common shares from continuing operations for the year ended December 31, 2002, was $747 million or $1.56 per share compared to $686 million or $1.44 per share for 2001 and $628 million or $1.32 per share for 2000. The increase in 2002 compared to 2001 is primarily due to higher earnings from the Transmission business and reduced expenses in the Corporate segment, partially offset by lower earnings from the Power segment. The increase in 2001 compared to 2000 was primarily due to higher earnings from the Power business, as well as reduced financial and preferred equity charges. In 2001, the Power segment earnings reflected the company's ability to capture significant market opportunities created by high market prices and power price volatility.

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 final tolls on its Canadian Mainline. The results for the year ended December 31, 2002 include after-tax net income of $36 million or $0.08 per share representing the impact of the Fair Return decision for 2001 ($16 million) and 2002 ($20 million). The 2002 results also include $7 million relating to TransCanada's proportionate share of a favourable ruling for Great Lakes Gas Transmission Limited Partnership (Great Lakes) with respect to Minnesota use tax paid in prior years. In 2002, TransCanada chose to expense stock options and the impact of this accounting change was a $2 million charge to net income for the year ended December 31, 2002.

Net income applicable to common shares from continuing operations in 2000 included gains on the sale of assets amounting to $30 million, after tax, or $0.06 per share, and tax recoveries of $28 million or $0.06 per share, reflecting the impact of tax law and income tax rate changes in the February 2000 and October 2000 Federal budgets.

TRANSCANADA – STRATEGY

TransCanada's Mission is to be one of the most profitable, competitive and reliable providers of wholesale natural gas transportation and electric power across North America, with strong roots in the Western Canada Sedimentary Basin (WCSB) and key customer relationships in consuming regions.

TransCanada's Strategies to achieve this mission continue to be:

- Sustain, grow and optimize the company's North American natural gas transmission business;
- Establish a new regulated business model that provides value to customers, reduces the long-term risks of the Canadian long-haul pipelines and allows the company to earn a fair and competitive return;
- Grow the power business;
- Pursue operational excellence, with a focus on providing low-cost, reliable service to the company's customers;
- Maintain and utilize the company's strong financial position.

TRANSCANADA – DEVELOPMENTS

TransCanada's focus on the disciplined implementation of the strategies resulted in strong financial performance in 2002 with increases in net income and operating cash flow, as well as the maintenance of a solid balance sheet. Strong internally generated cash flow allowed TransCanada to continue to repay debt maturities, invest in the core businesses of natural gas transmission and power, and maintain a strong liquidity position. In addition, TransCanada's financial position and performance enabled the Board of Directors to raise the quarterly dividend on the company's common shares from $0.20 per share in 2000, to $0.225 per share in 2001, to $0.25 per share in 2002, and to $0.27 per share for the quarter ended March 31, 2003.

The company's access to capital markets remains strong. During 2002, TransCanada established a new $1.5 billion syndicated credit facility, replacing existing lines of credit set to expire in mid-2003, and also filed universal shelf prospectuses with Canadian and United States securities regulators qualifying for issuance $2 billion and US$1 billion of securities, respectively.

The company invested more than $800 million in natural gas transmission and power assets in 2002 pursuant to the strategies of growing and optimizing the natural gas transmission network and power business. In the Transmission business, TransCanada continued to connect incremental natural gas supply within the WCSB, expanded its pipeline system in western Alberta and British Columbia to meet growing demand in California and the Pacific Northwest, and achieved growth in its investments in North American Pipeline Ventures (NAPV). In 2002, TransCanada pursued pipeline opportunities to move Mackenzie Delta and Alaska North Slope natural gas to markets throughout North America. In the Power business, TransCanada started operations at two new power plants, completed the acquisition of the ManChief power plant and announced plans to acquire a 31.6 per cent equity interest in Bruce Power L.P. for $376 million, subject to closing adjustments.

TransCanada held extensive discussions with industry stakeholders throughout 2002 on a future business model for its Canadian regulated pipelines. These stakeholder discussions and TransCanada's view of the future business model influenced the 2003 Canadian Mainline Tolls and Tariff Application filed with the NEB in September 2002 and the proposed rate design changes to the Alberta System filed with the Alberta Energy and Utilities Board (EUB) in January 2003. In June 2001, TransCanada filed the Fair Return application with the NEB, seeking an after-tax weighted average cost of capital (ATWACC) of 7.5 per cent to be included in the Canadian Mainline tolls for 2001 and 2002. In June 2002, following a hearing, the NEB released its decision not to adopt the ATWACC methodology, but did increase the deemed common equity from 30 per cent to 33 per cent.

Although disappointed with the NEB's decision, which in TransCanada's opinion does not adequately recognize the long-term business risks of the Canadian Mainline, the company remains committed to the Canadian pipeline business. In February 2003, the NEB denied TransCanada's request for a review and variance of the Fair Return decision.

TRANSCANADA – OUTLOOK

TransCanada will continue to implement its strategy in 2003. The company's main focus in 2003 will be to evaluate opportunities to grow and optimize the natural gas transmission and power businesses with a view to enhancing shareholder value and meeting customers' unique requirements in a constantly changing marketplace. The company will also focus on TransCanada's commitment to an operational excellence business model and advancement of the future business model for its Canadian regulated pipelines. The company's earnings and cash flow, combined with the solid balance sheet and liquidity at December 31, 2002, provide the financial flexibility for TransCanada to make disciplined investments in the two core businesses, with a primary focus on the acquisition and construction of highly efficient and well-positioned assets.

In February 2003, TransCanada announced a settlement with the customers on the Alberta System. This settlement, if approved by the EUB, will result in a decline in the fixed revenue requirement from $1.347 billion in 2002 to $1.277 billion in 2003. A reduction in 2003 net earnings as a result of this settlement is expected to be approximately $40 million after tax. TransCanada worked with its customers to negotiate a settlement that represented a balance of customer and shareholder interests. However, the Fair Return decision rendered by the NEB had a significant impact on the terms of reaching the settlement, as it provided a benchmark for negotiations on the Alberta System.

TRANSCANADA – COMPETITIVE STRENGTHS

The company's competitive strengths continue to be:

Transmission

- *Unparalleled Market Access* High capacity connections from the WCSB to premier North American markets give the company a strategic position in the continental natural gas market, offering producers the connectivity, penetration and flexibility they need to capitalize on growing demand. With the current capacity, infrastructure, market access, and ease of expansion offered by TransCanada's transmission systems, the company has a competitive advantage in attracting new natural gas supply from the North and British Columbia.
- *Experience and Expertise* TransCanada has a half century of expertise in large diameter, cold weather natural gas pipeline construction. The company is a leading builder and operator of large gas turbine compressor stations, and is the operator of one of the largest, most sophisticated, remote-controlled pipeline networks in the world.
- *Operational Excellence* The company has a solid reputation for reliability and safety and is focused on providing low-cost, reliable service by utilizing and applying innovation and best practices.

Power

- *Broad Understanding of Continental Markets* TransCanada has extensive knowledge of North American energy markets, opportunities and competitors, with an in-depth understanding of the company's core markets. In addition, the company has significant power deregulation experience.

- *Ability to Structure Deals and Manage Risk* The company's analytical, deal structuring and risk management skills have been a key element of success, complemented by marketing operations to capitalize on opportunities presented by market volatility.
- *Operational Excellence* TransCanada's power business is characterized by a commitment to industry-leading performance, as evidenced by a highly efficient generating fleet of turbines that operated at an average availability of 95 per cent in 2002. The company's strong management team has a proven track record in maximizing value from existing assets and in developing quality opportunities, both in new acquisitions and greenfield projects.

TRANSCANADA – CHALLENGES AND OPPORTUNITIES

The two most significant challenges to TransCanada's pipeline business in the long term are competition and the risk of declining supply in the WCSB. Over the past several years TransCanada has been working diligently with all stakeholders to provide value to its customers in the form of flexible, cost-competitive services and to earn a fair risk-adjusted return on its pipeline assets.

There will be significant opportunities to continue to grow TransCanada's pipeline business. North American natural gas demand is expected to grow by more than 25 per cent over the next 10 years. There is considerable concern that supply from the traditional supply basins in North America will not be able to meet this increased demand for natural gas. Alternative supplies such as from Alaska, the Mackenzie Delta and liquefied natural gas (LNG) may be required to meet this demand. TransCanada is well-positioned to build and operate the infrastructure to bring these new supplies to market.

TransCanada's high capacity connections from the WCSB to premier North American markets position the company well to move northern natural gas. TransCanada brings real competitive advantages to these projects. In the event that incremental LNG imports will be needed to meet market requirements in North America, TransCanada has the technology and pipeline capacity to bring this supply to market. Both the northern gas and LNG supplies are longer term prospects for TransCanada.

The growth of TransCanada's power business faces a number of challenges, including the uncertainties related to deregulation, long-term availability of fuel at economic prices, excess power generation, and the price of power in the long term.

TransCanada's strategy to grow its power business is supported by an expectation that the majority of the increase in natural gas demand is driven by the demand for power. Although there has been a significant increase in power supply in some markets over the past few years, TransCanada believes that there are niche opportunities available to build its power business. The increased demand for power and steam in the Alberta oil sands and other industrial sectors presents significant opportunities for growth. TransCanada has significant experience and competitive advantages in developing cogeneration facilities.

A key aspect to TransCanada's growth strategy focuses on the acquisition of existing pipeline and power assets. As a result of economic turmoil experienced by certain of TransCanada's competitors, the company expects to pursue acquisition opportunities that would create shareholder value.

ALBERTA SYSTEM

TransCanada's 100 per cent owned natural gas transmission system in Alberta gathers natural gas for use within the province and delivers gas to provincial boundary points for connection with the Canadian Mainline, BC 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 British Columbia to the U.S. border, serving markets in British Columbia as well as the Pacific Northwest, California and Nevada.

Transmission

HIGHLIGHTS

Earnings Increase Net earnings from the Transmission business increased $68 million to $653 million in 2002 compared to $585 million in 2001. Contributing to this increase were the Alberta System – $10 million, Canadian Mainline – $33 million and NAPV – $24 million.

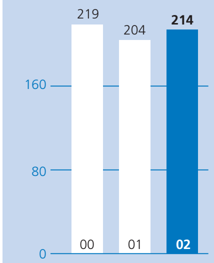
Alberta System The 2001/2002 Alberta System Rate Settlement (ASRS) expired at the end of 2002. Through a consultative process with major stakeholders, TransCanada reached a one-year settlement to establish a fixed revenue requirement for 2003. The settlement, together with proposed modifications to rate design, and new services currently before the EUB for approval, will form the basis of the Alberta System's tolls for 2003.

Canadian Mainline In June 2002, TransCanada received the NEB's Fair Return decision to determine the cost of capital to be included in the calculation of 2001 and 2002 tolls on TransCanada's Canadian Mainline. Despite the fact that the NEB granted an increase in the Canadian Mainline's deemed common equity ratio from 30 to 33 per cent, TransCanada was disappointed with this decision, and the NEB's denial of the request for a review and variance of the Fair Return decision, because it did not adequately recognize the long-term business risks to the Canadian Mainline.

TRANSMISSION RESULTS-AT-A-GLANCE

Year ended December 31	2002	2001	2000
(millions of dollars)			
Wholly-Owned Pipelines			
Alberta System	**214**	204	219
Canadian Mainline	**307**	274	281
BC System	**6**	5	6
	527	483	506
North American Pipeline Ventures			
Great Lakes	**66**	56	52
TC PipeLines, LP	**17**	15	11
Iroquois	**18**	16	13
Portland	**2**	(1)	(2)
Foothills	**17**	20	22
Trans Québec & Maritimes	**8**	8	8
Tuscarora	**–**	–	9
CrossAlta	**13**	8	6
Northern Development	**(6)**	(9)	(3)
Other	**(9)**	(11)	1
	126	102	117
Net earnings	**653**	585	623

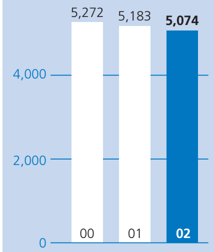
In 2002, net earnings from the Transmission business were $653 million, compared to $585 million and $623 million in 2001 and 2000, respectively. The increase in 2002 over 2001 was mainly due to the Canadian Mainline Fair Return decision, higher incentive earnings from wholly-owned pipelines, and higher earnings from TransCanada's investment in Great Lakes. The decrease in 2001 over 2000 was mainly due to lower earnings from the Alberta System and Canadian Mainline as well as higher costs related to the company's Northern Development activities.



ALBERTA SYSTEM NET EARNINGS
(millions of dollars)

WHOLLY-OWNED PIPELINES – FINANCIAL REVIEW

Alberta System Net earnings of $214 million in 2002 are $10 million higher than 2001 and $5 million lower than 2000. The increase over 2001 was primarily due to an interest refund of $4 million relating to a prior year income tax reassessment, and the expiry of TransCanada's transition support costs with respect to the products and receipt point pricing structure introduced in 2000. Earnings in 2002 and 2001 were both lower than 2000 earnings as a result of a lower implicit rate of return on equity in the ASRS compared to the Cost Efficiency Incentive Settlement (CEIS) that expired at the end of 2000. Under the ASRS, the majority of the Alberta System revenue requirement for 2002 and 2001 was at negotiated amounts of $1.347 billion and $1.390 billion, respectively.

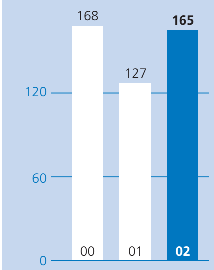


ALBERTA SYSTEM AVERAGE INVESTMENT BASE
(millions of dollars)

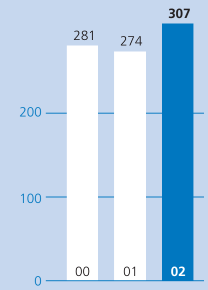
The Alberta System is one of the largest volume carriers of natural gas in North America and delivered 4,146 billion cubic feet (Bcf) of natural gas in 2002, as compared to deliveries of 4,059 Bcf in 2001 and 4,490 Bcf in 2000. The volumes transported by the Alberta System in 2002 represented approximately 17 per cent of total North American natural gas production and about 68 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 the approval of the EUB.

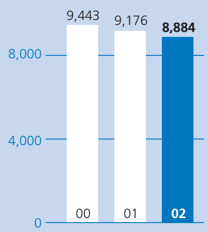
Canadian Mainline The Canadian Mainline generated net earnings of $307 million in 2002, an increase of $33 million and $26 million compared to 2001 and 2000, respectively. The increase in net earnings in 2002 was primarily due to the Fair Return decision by the NEB in June 2002, which included an increase in the deemed common equity ratio from 30 to 33 per cent effective January 1, 2001. Net earnings in 2002 reflected the impact of the Fair Return decision for both 2001 and 2002. The increase in earnings was partially offset by a decline in the NEB approved rate of return on common equity from 9.90 per cent in 2000 to 9.61 per cent in 2001 to 9.53 per cent in 2002, combined with a lower average investment base.



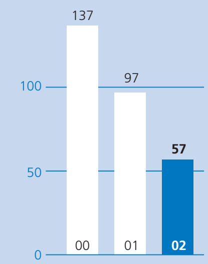
ALBERTA SYSTEM CAPITAL EXPENDITURES
(millions of dollars)



CANADIAN MAINLINE NET EARNINGS
(millions of dollars)



CANADIAN MAINLINE AVERAGE INVESTMENT BASE
(millions of dollars)



CANADIAN MAINLINE CAPITAL EXPENDITURES
(millions of dollars)

Annual deliveries of natural gas on the Canadian Mainline totaled 2,630 Bcf in 2002, compared to deliveries of 2,450 Bcf in 2001 and 2,675 Bcf in 2000. In 2002, deliveries to export border points comprised approximately 53 per cent of total deliveries compared to approximately 50 per cent in 2001 and 2000.

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 availability of incentive earnings affect the net earnings of the Canadian Mainline.

WHOLLY-OWNED PIPELINES – DEVELOPMENTS

Regulatory As part of TransCanada's plan to establish a new regulated business model, the company held extensive discussions with industry stakeholders in early 2002. The new regulated business model proposes changes to TransCanada's Canadian regulated pipeline business that would enhance the company's ability to compete for future market demand and gas supply while bringing benefits to customers. This regulated business model is intended to advance the evolution of TransCanada's rate and service offerings on all three of its wholly-owned pipelines (Alberta System, Canadian Mainline and BC System).

In the 2003 Canadian Mainline Tolls and Tariff Application, TransCanada seeks to increase the existing minimum bid floor price of IT from 80 per cent to 110 per cent of the Firm Transportation (FT) toll. This proposed change will better reflect the value associated with the reliability and flexibility currently inherent with IT, and will enhance the relative value of FT on the Canadian Mainline. TransCanada also proposes to establish a new geographic area in southwestern Ontario for tolling purposes. TransCanada believes the creation of this new tolling zone will increase market liquidity in the area, make TransCanada's tolls more reflective of actual costs, and ultimately improve TransCanada's competitiveness.

TransCanada has developed and filed for approval with the EUB proposed rate design changes to its Alberta System. The proposed changes include an intra-Alberta delivery toll, a short-haul transportation service, a price-matching service, and improved cost accountability for capacity expansions. Based on a settlement with its stakeholders, TransCanada applied in February 2003 to the EUB for approval of the 2003 revenue requirement.

Operational Excellence TransCanada continued its commitment to operational excellence in 2002 by advancing initiatives that will improve the company's ability to provide low-cost, reliable and responsive service to customers. Fundamentally, TransCanada continues to pursue this strategy in order to become the preferred company that customers choose to connect new gas supplies and markets.

Objectives in 2002 that focused on improving levels of customer service to Transmission customers included enhancing TransCanada's responsiveness to resolving customer issues, building effective relations with customers' senior management, and consolidating and improving TransCanada's information systems for managing customer transactions.

Specific 2002 objectives established within TransCanada's operations and engineering functions included operating and maintenance cost-related targets, per unit capital costs, and maintenance and operating costs per gas volume transported. These objectives were met or exceeded.

Supply Growth In 2002, TransCanada continued to connect incremental gas supply within the WCSB, both in Alberta and British Columbia. The Northwest Mainline Expansion project was completed in early 2002. Located along the western edge of Alberta, this additional pipeline capacity accommodates incremental receipt contract volumes of approximately 415 million cubic feet per day (MMcf/d) to be transported from the Ladyfern area of British Columbia. The Narraway Extension project was also completed in 2002, and resulted in incremental volumes of approximately 100 MMcf/d from the Narraway and Cutbank areas of western Alberta. In addition, TransCanada negotiated a competitive service offering in the Suffield area of Alberta to retain natural gas supply, which would have otherwise bypassed the Alberta System.

The timely connection of these significant 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.

Market Growth TransCanada continues to pursue growth opportunities within existing and new natural gas markets. In 2002, TransCanada expanded its pipeline system in western Alberta and British Columbia by approximately 350 MMcf/d to meet growing market demand in California and the Pacific Northwest.

TransCanada continues to strengthen business relations with customers in the Fort McMurray area. This market, located in northeastern Alberta, is comprised of oil sands and upgrading plants that are heavily reliant on natural gas as a source of fuel. In 2002, TransCanada experienced steady growth of delivered gas volumes to this market. Looking forward, this market represents one of the largest growth opportunities for natural gas demand in North America. In other geographic regions of Alberta, TransCanada connected both new and expansion projects for existing and smaller markets.

WHOLLY-OWNED PIPELINES – OUTLOOK

TransCanada's Transmission business has a long history of providing market access and connecting gas supply for its customers. As the marketplace has evolved and competition has grown, the wholly-owned pipelines business has focused on providing market-responsive products and services, a competitive cost structure, and world-class levels of reliability to its customers.

In 2003, the wholly-owned pipelines business will focus on achieving additional efficiency improvements in all aspects of the business, by maintaining focus on operational excellence and leveraging technological advancements. TransCanada will also continue to work collaboratively with all stakeholders on resolving jurisdictional issues, advancing regulated business model changes and addressing fair return challenges.

Looking forward, in order to replace declines in production, producers will continue to explore and develop other fields that are geologically similar to the Ladyfern project and unconventional supply such as the recently connected initial gas production from coal bed methane reserves to the Alberta System. As new reserves are developed in the WCSB, TransCanada will seek to connect these additional natural gas supplies to the Alberta System.

TransCanada's net income is not directly affected by fluctuations in the commodity price of natural gas, but such fluctuations may influence both production levels and the natural gas basin from which North American users elect to purchase natural gas supplies. Under the current regulatory model, TransCanada's net income from its wholly-owned pipelines is not materially affected by fluctuations in throughput.

Earnings In 2003, the net earnings from wholly-owned pipelines are expected to be significantly lower than in 2002.

For the Alberta System, the one-year fixed 2003 revenue requirement settlement reached between TransCanada and its stakeholders will negatively impact Alberta System's 2003 net earnings by approximately $40 million after tax, as compared to 2002.

The 2002 Canadian Mainline earnings included the recognition of the impact of the Fair Return decision on 2001, which will not be repeated in 2003. The 2003 net earnings from the Canadian Mainline will depend on the outcome of the 2003 Tolls and Tariff Application currently before the NEB. Approval of the 2003 Tolls and Tariff Application as filed would significantly increase TransCanada's revenue and cash flow due to increased depreciation. However, higher depreciation has a negative earnings impact due to the associated reduction of the investment base.

Capital Expenditures Total capital spending for the wholly-owned pipelines during 2002 was $272 million. Capital expenditures in 2002 included approximately $113 million to expand transmission capacity on the Alberta and BC Systems to serve growing markets in California and the Pacific Northwest. Capital spending in 2003 is expected to decrease by approximately $70 million from 2002, primarily due to lower capacity capital spending requirements.

WHOLLY-OWNED PIPELINES – BUSINESS RISKS

Competition and Regulation TransCanada faces competition at both the supply end and the market end of its system. 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 British Columbia to the Chicago area, and the continuing expiry of transportation contracts have resulted in significant reductions in firm contracted capacity on both the Alberta System and the Canadian Mainline. The Canadian Mainline has effectively become the "swing" pipeline out of the WCSB, absorbing the bulk of any volume swings in the supply area.

Based on TransCanada's year-end 2001 estimates, the WCSB had remaining discovered reserves of 56 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. 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.

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 gas to two large mainline systems for domestic and export deliveries. The Alberta System faces competition primarily from the Alliance Pipeline, which connects to some of the same gas plants. The maximum receipt capacity of the Alliance Pipeline is approximately 1.7 Bcf/d compared to TransCanada's Alberta System average 2002 receipt volumes of 11.2 Bcf/d. Two bypass pipelines in southern Alberta connect to the Canadian Mainline and have a combined capacity of 0.4 Bcf/d. 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 pipeline serving mid-western and eastern markets in Canada and the U.S. The demand for gas in TransCanada's key eastern markets is expected to continue to increase, particularly to meet the expected growth in gas-fired power generation. TransCanada does, however, face competition for its transportation services to eastern Canadian markets and U.S. export points. The main source of this competition is the combination of the Alliance and Vector pipelines. Alliance transports gas from the WCSB to the U.S. Midwest, where Vector connects to Alliance and transports gas to Eastern Canada, essentially allowing a complete bypass of the Canadian Mainline. In addition, there are several smaller pipeline systems that compete with TransCanada for markets in Eastern Canada. TransCanada must also compete to retain and attract customers in the northeastern U.S. market where consumers have access to an array of supply options such as U.S. supplies, imported LNG supplies, and natural gas from the Canadian East Coast offshore supply basin. New market growth customers and existing customers with expiring FT contracts may take advantage of these alternatives.

The increased competitive environment has resulted in contract non-renewals on both the Alberta System and the Canadian Mainline. There are significant quantities of excess firm capacity available for IT service as a consequence of FT service contract non-renewals on the Canadian Mainline. As a result, IT service provides some shippers with flexibility and a level of reliability comparable to FT service. In 2002, IT service pricing for the Canadian Mainline was determined based on bids received by shippers with a floor price of 80 per cent of the FT price. The Canadian Mainline has had reductions in FT contracts for deliveries originating at the Alberta border and in Saskatchewan of approximately 2.1 Bcf/d, or approximately 31 per cent of its capacity. As a result of reduced contracted FT volumes, tolls have increased on the Canadian Mainline. However, the toll increases due to contract non-renewals are somewhat mitigated by higher volumes flowed under IT contracts. Looking forward, there is limited opportunity to reduce tolls by increasing volumes on the Canadian Mainline. The utilization of the Canadian Mainline is not expected to increase in the short to medium term as additional supply from the WCSB is expected to be absorbed by demand growth within Western Canada and higher flows on other pipeline systems.

One of the responses by the Transmission business towards increased competition has been to focus on changes to the regulated business model. TransCanada will continue to work with stakeholders in 2003 to advance various aspects of the company's competitive business model for the Alberta System, Canadian Mainline and BC System.

For the Canadian Mainline, TransCanada has filed an application with the NEB in the 2003 Tolls and Tariff Application to increase the depreciation rate and further the company's initiatives on services and pricing. The decisions by the NEB on TransCanada's 2003 Tolls and Tariff Application may have an impact on TransCanada's 2003 earnings. In February 2003, the NEB denied TransCanada's request for a review and variance of the Fair Return decision. As a result, the company has concerns about the long-term implications of a financial return that discourages additional investment in existing Canadian natural gas transmission systems.

The EUB is currently considering holding a generic cost of capital inquiry for all Alberta utilities. TransCanada's position is that the inquiry should not apply to the Alberta System. Should the EUB proceed with the inquiry and should the Alberta System be subject to the inquiry, TransCanada will fully advance its views on the level of returns that are required to induce investment in pipelines.

Safety TransCanada worked closely with regulators, customers and communities during 2002 to ensure the continued safety of employees and the public. In 2002, two line breaks occurred in relatively remote areas of Manitoba and Alberta resulting in minimal impact. Pipeline integrity expenditures, including increased spending as a result of these line breaks, are anticipated to be approximately $80 million in 2003 compared to $53 million in 2002. 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 2002, TransCanada continued efforts to minimize the impact of operations on the environment through continuous improvements to the leak detection and repair program and blowdown emissions management program. Through the use of innovative technology, TransCanada is able to quantify leaks and prioritize them for repair. TransCanada also tested a new technology for minimizing the impacts from pipeline blowdowns. This technology incinerates gas that would have normally been vented after the use of a portable transfer compressor and, as a result, significantly reduces the amount of greenhouse gases emitted to the atmosphere.

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

NORTH AMERICAN PIPELINE VENTURES – FINANCIAL REVIEW

NAPV is comprised of TransCanada's direct and indirect investment in various natural gas pipelines and pipeline-related businesses. NAPV also includes project development activities related to TransCanada's pursuit of new natural gas pipeline and pipeline-related opportunities in the North and throughout North America.

TransCanada's proportionate share of net income in 2002 from NAPV was $126 million compared to $102 million and $117 million in 2001 and 2000, respectively. The increased net earnings of $24 million in 2002 compared to 2001 were due to $17 million of higher earnings from U.S. affiliates which included TransCanada's $7 million share of a favourable ruling for Great Lakes related to Minnesota use tax paid in prior years. Also contributing to higher earnings from U.S. affiliates were the increased ownership interests in Iroquois Gas Transmission System (Iroquois) and Portland Natural Gas Transmission System (Portland) acquired in mid-2001, higher transportation margins, and favourable exchange rates. While TransCanada recorded lower earnings from Foothills Pipe Lines Ltd. (Foothills) of $3 million due to a lower return on equity and declining rate base, this was more than offset by earnings from CrossAlta Gas Storage & Services Ltd. (CrossAlta) which increased significantly 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 TransGas de Occidente S.A. (TransGas) and TransCanada Pipeline Ventures Limited Partnership (Ventures LP).

NAPV's net earnings of $102 million in 2001 decreased by $15 million compared to 2000. This decrease resulted from increased Northern Development and pipeline business development activities in 2001, and a one-time gain of $7 million from the sale of a 49 per cent interest in Tuscarora Gas Transmission Company (Tuscarora) to TC PipeLines, LP in 2000.

NORTH AMERICAN PIPELINE VENTURES – DEVELOPMENTS

In 2002, the Tuscarora and Ventures LP systems were expanded, an interest in Northern Border Partners, L.P. (NBPLP) was acquired, a settlement related to Portland's rates was reached, and TransCanada continued its active participation in Northern Development.

Great Lakes In 2002, Great Lakes received a favourable ruling relating to Minnesota use tax paid in prior years. TransCanada's share of this settlement was approximately $7 million.

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. In July 2002, TC PipeLines, LP increased its quarterly distribution from US$0.50 per unit to US$0.525 per unit. This represents the third increase in the partnership's quarterly cash distribution since the commencement of operations in May 1999.

Iroquois Construction on Iroquois' Eastchester Expansion is well under way. Some of the compression additions relating to this extension were placed in-service in November 2002 with the balance of the project expected to be complete and ready for in-service by mid-2003. This extension will extend Iroquois' system from Long Island into New York City and will provide an additional 230 MMcf/d of new service into this market.

Portland Portland filed a rate application with the Federal Energy Regulatory Commission (FERC) in October 2001 that was approved and went into effect, subject to refund, in April 2002. Portland and customer representatives reached an agreement on new tolls and Portland submitted an uncontested agreement to the FERC in October 2002, which was approved in its entirety in January 2003. The lower depreciation rates and revised tolls should have a positive impact on Portland's future earnings.

Northern Border Partners, L.P. In 2002, the company purchased an interest in NBPLP for $19 million, which provides TransCanada with a general partnership interest in NBPLP and a 17.5 per cent vote on the partnership policy committee. NBPLP owns the 70 per cent of Northern Border not owned by TC PipeLines, LP.

TQM Effective January 2003, TransCanada took over the field operations and administration functions of Trans Québec & Maritimes Pipeline Inc. (TQM). The transition phase should be mainly completed by the end of first quarter 2003.

CrossAlta TransCanada holds a 60 per cent interest in Crossfield Storage Joint Venture and is entitled to a similar share of the earnings of CrossAlta. CrossAlta reported strong results in 2002 due to higher storage margins, increased storage capacity and reduced operating costs.

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.

NORTHERN BORDER

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

IROQUOIS

Iroquois connects with the Canadian Mainline and delivers natural gas to customers in northeastern U.S. TransCanada has a 40.96 per cent interest in this 604 kilometre pipeline system.

PORTLAND

Portland operates a 471 kilometre pipeline which connects with TQM near Pittsburg, New Hampshire and has delivery points in Massachusetts. TransCanada has a 33.29 per cent interest in Portland.

Northern Development In 2002, TransCanada pursued pipeline opportunities to move both Mackenzie Delta and Alaska North Slope natural gas to markets throughout North America. TransCanada worked with key stakeholders in the interest of participating in any potential pipeline project.

TransCanada and Foothills held discussions in 2002 with Alaska North Slope producers regarding rate design, capital costs, commercial terms and timing of the Alaska Highway Pipeline. These producers are seeking legislative changes in Washington D.C. and Alaska to facilitate construction of a pipeline. Legislative initiatives are expected to continue in Washington D.C. and Alaska in 2003 to advance a project.

TransCanada has proposed an integrated solution to move Arctic gas to various markets across North America. The integration comes from connecting both the Mackenzie Delta and Alaska pipelines with the existing Alberta System. The Alberta System would be expanded as required for the combined volume of Arctic gas and western Canadian production. Expansions downstream from Alberta would be sized to reflect expected market supply and demand conditions at the time of construction. TransCanada's proposal provides producers with lower capital costs and significant market flexibility. The company continues to refine and discuss this plan with producers and other key stakeholders.

All costs incurred relating to Northern Development continue to be expensed as incurred.

NORTH AMERICAN PIPELINE VENTURES – STRATEGY AND OUTLOOK

TransCanada continues to actively pursue gas pipeline and pipeline-related development and acquisition opportunities in Canada and the U.S., 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.

As world geo-political events develop, they will have an impact on the level of development of future and existing gas supplies worldwide. This could impact TransCanada directly with its involvement in the development of natural gas transportation solutions as producers access gas reserves in the North and Atlantic Canada, as well as existing facility expansions across North America.

TransCanada is poised to play a key role in Northern Development. While there are many issues to be resolved before this development moves forward, TransCanada has competitive advantages including expertise in the design, construction and operation of large diameter pipe in cold weather conditions. TransCanada is also the leading builder and operator of large 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.

TQM

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

CROSSALTA

CrossAlta is an underground natural gas storage facility connected to TransCanada's Alberta System, and is located near Crossfield, Alberta. CrossAlta has a working gas capacity of 47 Bcf with a maximum deliverability capability of 475 MMcf/d. TransCanada holds a 60 per cent interest in CrossAlta.

FOOTHILLS

Foothills carries natural gas for export from central Alberta to the U.S. border to serve markets in the U.S. Midwest, Pacific Northwest and California. TransCanada owns 50 per cent of Foothills, 69.5 per cent of Foothills (Sask.), 74.5 per cent of Foothills (Alta.) and 74.5 per cent of Foothills (South B.C.). Together, these pipeline systems total 1,040 kilometres in length.

TUSCARORA

Tuscarora operates a 386 kilometre pipeline system transporting 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.

VENTURES LP

Ventures LP, which is 100 per cent owned by TransCanada, owns a 110 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.

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.

NORTH AMERICAN PIPELINE VENTURES – BUSINESS RISKS

Foreign Exchange A significant amount of the revenue in this business segment is generated from U.S. pipeline affiliates. The performance of the Canadian dollar compared 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 exposed to throughput risk and their revenues will experience some variability. Throughput risk is created by supply availability, economic activity, weather variability, and pricing of alternative fuels.

Insurance, Benefits and Interest Rates Insurance costs continue to rise as a result of events in the U.S. in 2001, while interest rates remain low. Also, the costs of employee benefits, particularly in the U.S., continue to increase. If these costs continue to rise and the economy recovers, resulting in increased interest rates, earnings of affiliated pipelines and businesses could be negatively impacted.

Regulation The U.S. partially-owned pipelines are regulated by the FERC while the Canadian partially-owned pipelines are regulated by the NEB. These regulators play a significant role in approving the pipelines' return on equity, capital structure, tolls and system expansion.

NATURAL GAS THROUGHPUT VOLUMES

(Bcf)	**2002**	2001	2000
Alberta System	**4,146**	4,059	4,490
Canadian Mainline	**2,630**	2,450	2,675
BC System	**371**	395	408
Great Lakes	**863**	804	898
Northern Border	**839**	821	853
Iroquois	**340**	314	344
Portland	**52**	44	40
Tuscarora	**20**	23	25
Foothills	**1,098**	1,117	1,186
Trans Québec & Maritimes	**175**	161	168
Ventures LP	**85**	60	36

Power

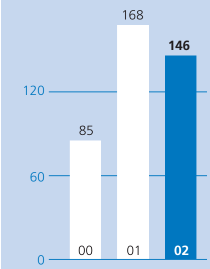
HIGHLIGHTS

Earnings In a year characterized by a downturn in the power industry, TransCanada's Power segment made a significant contribution to TransCanada's earnings in 2002 through strong base earnings from its plants, asset optimization and successful marketing activities in the New England and Alberta markets.

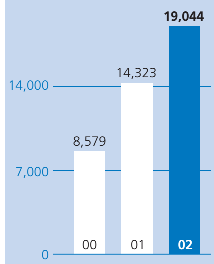
Expanding Asset Base TransCanada completed the acquisition of ManChief, which increased TransCanada's available power supply by 300 megawatts (MW). 2002 was the first year of operations for two new Alberta plants, Redwater and Carseland, with a third plant commencing operations in first quarter 2003.

Bruce Power L.P. TransCanada announced plans in December 2002 to acquire a 31.6 per cent equity interest in Bruce Power L.P., the operator and lessee of the Bruce nuclear power plant. This acquisition will indirectly increase TransCanada's nominal generating capacity by 992 MW starting in February 2003 with an additional 486 MW expected in mid-2003, which represents 31.6 per cent of the total plant output.

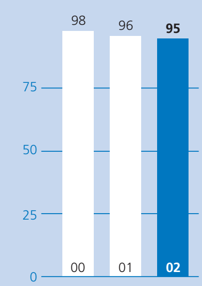
Operational Excellence Average plant availability in 2002 was 95 per cent with an average of 96 per cent plant availability over the past three years.



POWER NET EARNINGS
(millions of dollars)



POWER SALES VOLUMES
(gigawatt hours)



PLANT AVAILABILITY
(per cent)

POWER RESULTS-AT-A-GLANCE

Year ended December 31	**2002**	2001	2000
(millions of dollars)			
Northeastern U.S. operations	**149**	159	68
Western operations	**131**	149	59
Power LP investment	**36**	39	33
General, administrative and support costs	**(73)**	(49)	(21)
Operating and other income	**243**	298	139
Financial charges	**(13)**	(24)	(15)
Income taxes	**(84)**	(106)	(39)
Net earnings	**146**	168	85

TransCanada's Power business contributed $146 million of net earnings in 2002, a decrease of $22 million or 13 per cent, compared to very strong earnings of $168 million in 2001. This decrease is primarily attributable to TransCanada's ability to capitalize on market opportunities in both Northeastern U.S. and Western Operations in 2001 that did not exist in 2002.

In 2002, TransCanada focused on sustaining a base level of earnings and reducing exposure to volatile market conditions through additional long-term sales arrangements and expanding the asset base. Net earnings in 2002 from the Northeastern U.S. Operations also included a full year of earnings from the Curtis Palmer hydroelectric facilities purchased in July 2001. Western Operations' lower marketing margins in 2002 were partially offset by income from its expanding asset base. The Carseland and Redwater plants had their first full year of operations in 2002 and the ManChief plant was acquired in November 2002. Transactions under the Sundance B power purchase arrangement (PPA) also commenced in January 2002. TransCanada's earnings in 2002 were lower from the investment in TransCanada Power, L.P. (Power LP) due to the unplanned outage at the Williams Lake plant in the first half of 2002, reduced enhancement opportunities, and a reduction in

TransCanada's ownership interest from 41.6 per cent to 35.6 per cent in Power LP, effective October 2001. The increase in general, administrative and support costs in 2002 compared to the two prior years reflects the increased activity in TransCanada's Power business, as well as the company's focus on future growth in this segment.

Power's net earnings of $168 million in 2001 increased by $83 million compared to net earnings of $85 million in 2000. This increase reflected Power's ability to take advantage of market opportunities in 2001 created by high prices and power price volatility in both Northeastern U.S. and Western Operations, the acquisition of the Curtis Palmer facility in July 2001, and the commencement of transactions under the Sundance A PPA. Power's net earnings in 2000 included a $23 million after-tax gain on the sale of TransCanada's interest in the Hermiston Power Partnership.

NOMINAL GENERATING CAPACITY OF POWER PLANTS

(MW)	
TransCanada Power	
Ocean State	560
ManChief	300
MacKay River [1]	165
Carseland	80
Bear Creek	80
Curtis Palmer	60
Redwater	40
Cancarb	27
Bruce Power L.P. [2]	
Bruce A [3]	486
Bruce B [4]	994
Power LP [5]	
Williams Lake	66
Castleton	64
Tunis	43
Kapuskasing	40
Nipigon	40
North Bay	40
Calstock	35
Other [6]	
Sundance A	560
Sundance B	353
	4,033

1 Currently under construction.

2 TransCanada's purchase of a 31.6 per cent interest in Bruce Power L.P., which includes facilities consisting of eight nuclear reactors, was announced in December 2002 and closed in February 2003. The volumes in the table represent TransCanada's 31.6 per cent interest.

3 Bruce A consists of four 769 MW reactors, which are currently not operating. Two of the Bruce A units (3 and 4) are expected to be restarted and on-line by mid-2003, subject to receipt of all necessary regulatory approvals.

4 Bruce B consists of four reactors, which are currently in operation, with a capacity of approximately 3,140 MW. The generating capacity of 994 MW includes two MW from TransCanada's 17 per cent indirect share in Huron Wind L.P. which owns a nine MW wind farm.

5 At December 31, 2002, 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.

6 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.

POWER – DEVELOPMENTS

TransCanada's Power business had a strong performance in 2002 particularly considering the volatile and depressed market conditions. In a year in which the industry experienced many regulatory and market uncertainties, the Power business delivered on its growth objective through the acquisition of the ManChief plant, announcing its acquisition of a 31.6 per cent interest in Bruce Power L.P., a full year of operations at the Carseland and Redwater plants, and construction on the MacKay River and Bear Creek plants. Power also announced the formation of Portlands Energy Centre L.P., a partnership to assess the viability of developing a natural gas-fuelled energy centre to meet electricity needs in downtown Toronto. TransCanada continues to utilize its competitive strengths to seek acquisition and development opportunities that will complement the overall asset base and contribute positively to earnings and cash flow.

NORTHEASTERN U.S. OPERATIONS

Power's Northeastern U.S. Operations consists of two primary businesses, power generation and power marketing, in the New England and New York markets.

TransCanada owns 100 per cent of Ocean State Power (OSP), a 560 MW gas-fired plant located in Rhode Island, and the 60 MW Curtis and Palmer (Curtis Palmer) hydroelectric facilities near Corinth, New York. OSP earns a FERC-regulated return on equity on its investment, which has a declining rate base. Additionally, TransCanada Power Marketing Limited (TCPM), TransCanada's marketing affiliate in the region operating out of Westborough, Massachusetts, purchases 76.5 per cent of the output from OSP and re-markets this power to third parties for terms extending out to 2009. Output from Curtis Palmer is generated into the New York Power Pool and sold under a fixed-price, long-term power purchase agreement to Niagara Mohawk Power Corporation for a term of more than 25 years. Curtis Palmer enjoys a high capacity factor due to its strategic location just downstream of certain water storage facilities on the Hudson River. However, it is subject to variations in water levels.

TCPM has also contracted with third parties for additional supplies that are re-marketed in a portfolio of wholesale and large retail arrangements. This includes TCPM's purchase of 100 per cent of the output of the 64 MW gas-fired combined-cycle plant located in Castleton-on-Hudson, New York (Castleton), which is owned by Power LP.

TransCanada's continued success and growth in the northeastern U.S. is the direct result of a very efficient, controlled risk marketing operation. TCPM is focused on selling power under varying contract terms to wholesale and retail industrial customers while managing its portfolio of power supplies. Through active portfolio management, TCPM has positioned itself to capture market opportunities as they arise, while reducing downside exposure.

Northeastern U.S. Operations' operating income of $149 million in 2002 was slightly lower than the unprecedented $159 million earned in 2001. Operating income in 2002 was strong considering the general retrenchment and softness of the wholesale power markets in 2002. 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. In 2002, TCPM substantially increased its earnings from, and presence in, the retail customer sector by

OCEAN STATE

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

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-price, long-term agreement.

CASTLETON

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

selling more volumes and services to large industrial and commercial customers. In December 2002, OSP concluded an arbitration process with respect to its cost of fuel gas, which will substantially increase OSP's costs. The matter is presently in another arbitration process in 2003 with a decision expected in second quarter of 2003.

Over the past five years, TCPM has firmly established itself as a leading energy provider in the New England power market. TransCanada continues to look for opportunities to augment its existing operations and successful marketing business in the region, including the potential to increase its presence in the New York market.

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.

SUNDANCE A & B

The Alberta Sundance power plant 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.

WESTERN OPERATIONS

The focus of Western Operations is to optimize and expand its existing asset base and maximize the potential rewards through a combination of long- and short-term contracts and low cost generation and supply. In addition to growing the Alberta cogeneration facilities, TransCanada's Power business further diversified its Western portfolio in 2002 through the acquisition of the 300 MW ManChief plant.

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 generation from the Alberta plants and the purchase and resale of electricity related to the Sundance PPAs. Western Marketing also participates in marketing electricity across Canada and throughout the northern tier of the U.S. from Washington to Wisconsin. Plant Operations consists of contributions from TransCanada's Alberta power plants, the newly acquired ManChief plant in Colorado, and fees earned to manage Power LP and operate its seven plants.

Operating income attributable to Western Operations decreased by 12 per cent from $149 million in 2001 to $131 million in 2002. Market opportunities that existed in 2001 resulting from high power prices (average Alberta Pool Price of $71/megawatt hour (MWh) in 2001 compared to $44/MWh in 2002) 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 Sundance B PPA and the Redwater, Carseland and ManChief plants.

The increase of $90 million in operating income from 2000 to 2001 was primarily due to the increased volumes commencing January 2001 from the acquisition of the 560 MW Sundance A PPA and increased commercial activity that capitalized on opportunities created by higher power prices and price volatility in Western Canada and the Pacific Northwest regions. Operating income in 2000 included a $26 million gain on sale of the Hermiston plant.

Western Marketing In December 2001, through a partnership arrangement, TransCanada effectively acquired 50 per cent of the remaining rights and obligations of the 706 MW Sundance B PPA. Beginning in January 2002, this acquisition provided TransCanada with an additional 353 MW of supply for the next 19 years. The Sundance A PPA that was acquired in August 2000 provides 560 MW of supply for a 17 year period.

In order to mitigate market price risk, TransCanada has sold essentially all of its Sundance PPA power supply in 2003 and 77 per cent of the expected, average combined power supply for the next three years. TransCanada continues to secure additional long-term sales contracts for the remaining Sundance power supply, as well as any uncontracted supply from its Alberta power plants.

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 its expertise in developing new projects and becoming a prominent player in the Alberta market. The Carseland and Redwater cogeneration plants successfully completed their first year of operation in 2002.

The Bear Creek plant will begin commercial operations in first quarter 2003. This 80 MW cogeneration facility near Grande Prairie, Alberta will sell the majority of its power to Weyerhaeuser at its Grande Prairie Pulp Mill, as well as Weyerhaeuser's other Alberta facilities. The construction of the MacKay River plant is continuing and is expected to be in operation in late 2003. This 165 MW cogeneration facility near Fort McMurray, Alberta will provide electricity and steam to Petro-Canada's adjacent in-situ oil sands operations.

Both the Bear Creek and the MacKay River plants have followed the strategic power development model that was designed for Redwater and Carseland. Under this model, TransCanada is generally able to expand its portfolio of power plants while avoiding excessive price risk through the long-term sale of electricity and steam/heat to the adjacent industrial customer for a portion of the plant output while, at the same time, retaining a certain amount of merchant power capacity. Upon completion in late 2003, the MacKay River plant will be TransCanada's largest power plant in Alberta, and will increase TransCanada's directly controlled supply in the province to more than 1,300 MW.

TransCanada expanded its generation base in 2002 through the acquisition of the 300 MW ManChief facility. This facility is a simple-cycle, two-turbine facility near Brush, Colorado. The operations and maintenance services for the ManChief plant will continue to be supplied by the current contracted service provider, Colorado Energy Management, LLC. This new addition to TransCanada's portfolio of generation assets meets the objective of creating stable and predictable cash flows as the entire capacity is sold under long-term tolling contracts that expire in 2012.

POWER LP INVESTMENT

Power LP Investment includes the earnings generated from holding TransCanada's investment in TransCanada Power, L.P. which is 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 the three.

CARSELAND

TransCanada completed construction of an 80 MW natural gas-fired cogeneration plant near Carseland, Alberta in September 2001, with commercial operation commencing in January 2002.

REDWATER

TransCanada completed construction of a 40 MW natural gas-fired cogeneration plant near Redwater, Alberta in November 2001, with commercial operation commencing in January 2002.

BEAR CREEK

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

MACKAY RIVER

This 165 MW facility near Fort McMurray, Alberta is currently under construction. The expected completion date is late 2003.

WILLIAMS LAKE

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

CALSTOCK

Calstock is fuelled by a combination of waste wood 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.

CANCARB

The 27 MW Cancarb power plant is fuelled by waste heat from TransCanada's adjacent thermal carbon black facility.

TransCanada acts as manager for Power LP. In this capacity, TransCanada manages the operations and maintenance requirements of Power LP and minimizes its exposure to gas price fluctuations by locking in much of the required gas supply under predetermined long-term contracts. In addition, when market conditions warrant, TransCanada enhances the overall operating profits of Power LP by curtailing certain plants during off-peak hours and selling the displaced gas at attractive market prices, resulting in increased overall net earnings for Power LP.

Operating income from TransCanada's investment in Power LP decreased $3 million or eight per cent compared to 2001 mainly as a result of decreased ownership throughout 2002 compared to 2001, reduced enhancement opportunities, and an unplanned outage at the Williams Lake plant in the first half of 2002. In October 2001, Power LP issued approximately 5.7 million units in a public offering which decreased TransCanada's ownership interest from 41.6 per cent to 35.6 per cent. At December 31, 2002, the Power LP units closed at $30.90 on The Toronto Stock Exchange and TransCanada owned approximately 14.0 million units.

As noted, TransCanada provides management services to Power LP. This, combined with TransCanada's ownership share, has resulted in Power LP being a key asset in growing TransCanada's overall power business. Power LP has grown substantially since its inception in mid-1997 and will continue to pursue further growth in the future.

BRUCE POWER L.P.

In February 2003, the company completed the acquisitions of a 31.6 per cent interest in Bruce Power L.P. and an approximate 33.3 per cent interest in Bruce Power Inc., the general partner of Bruce Power L.P., for $376 million, subject to closing adjustments. TransCanada also funded a one-third share ($75 million) of a $225 million accelerated deferred rent payment to Ontario Power Generation (OPG).

TransCanada acquired the interests as part of a consortium (the Consortium) that includes Cameco Corporation (Cameco) and BPC Generation Infrastructure Trust, a trust established by the Ontario Municipal Employees Retirement System. Under the agreement, the Consortium acquired British Energy (Canada) Ltd. (British Energy), which owns a 79.8 per cent interest in Bruce Power L.P. as well as a 50 per cent interest in the nine MW Huron Wind L.P. power facility. Bruce Power L.P. is the tenant under a lease with OPG on the Bruce nuclear power facility. The lease expires in 2018 with an option to extend the lease by up to 25 years. The Bruce power facility will continue to be managed and operated by the management and staff of Bruce Power L.P. Spent fuel and decommissioning liabilities remain the responsibility of OPG.

TransCanada recorded this acquisition as an equity investment and will report the income as equity income.

Through the use of PPAs, Bruce Power L.P. has sold approximately 45 per cent of its expected combined Bruce A and B output for 2003, 40 per cent for 2004 and 30 per cent for 2005.

POWER – STRATEGY AND OUTLOOK

TransCanada will capitalize on opportunities resulting from industry changes and grow through the addition of new power supplies. TransCanada will continue its pursuit of operational excellence as new plants are added. Expansion of Northeastern U.S. Operations and Western Operations will continue with a balanced portfolio of short-term marketing around existing operations and new opportunities combined with medium- to long-term sales to industrial customers. TransCanada will continue to market power generation to maximize the value of the portfolio of power assets and strengthen cash flows. The company will evaluate additional acquisition opportunities of various sizes in target markets that are consistent with its strategy, directly or through Power LP.

Power continues to have significant opportunities for growth in both the near and long term. The current state of the power industry provides both opportunities and challenges to TransCanada. A combination of acquisitions, greenfield developments and further expansions of its existing businesses will allow Power to grow in a way that will optimize the asset mix. TransCanada expects to encounter challenges including reduced power prices, higher input prices, and construction risks of new plants. In order to overcome these challenges, potential acquisition opportunities will include plants of varying fuel sources, such as the Bruce nuclear plant, to provide greater diversification in the company's asset portfolio. TransCanada will draw on the company's technical expertise and business models that have proved successful to date for new development projects. In addition, it will leverage off its market knowledge in the Alberta and New England deregulated markets as TransCanada increases its presence in Ontario.

The Ontario electricity market officially opened, at both wholesale and retail levels, on May 1, 2002. However, in November 2002, the government revised the marketplace through both statutes and regulations. Currently, rates for small consumers are capped at a maximum cost of 4.3 cents per kilowatt hour of power. This cap does not affect the wholesale market where TransCanada is primarily focused. The average wholesale price per kilowatt hour from May 2002 to February 2003 was approximately 30 per cent higher than the small consumer capped rate.

The net earnings from the Power business in 2003 are expected to be slightly higher than 2002 primarily due to TransCanada's investment in the Bruce, ManChief and Bear Creek power plants. Power will continue to seek opportunities to enhance its solid base earnings from the remainder of the generation supply business through active marketing and management of its entire portfolio mix. Earnings opportunities may be limited due to factors such as fluctuating gas costs, regulatory changes, weather, lack of price volatility, plant availability and overall stability of the power industry. In terms of growing its generation portfolio, Power will look for investments that will continue to provide stable, predictable cash flows through substantially contracted revenue streams or electricity generation at the low end of the cost dispatch curve.

BRUCE POWER L.P.

In February 2003, TransCanada acquired a 31.6 per cent share of Bruce Power L.P., which owns the Bruce nuclear power plant located near Lake Huron, Ontario. This investment indirectly increased TransCanada's nominal generating capacity by 992 MW, and an additional 486 MW is expected to be restarted and on-line in mid-2003.

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 excellent operating performance at each of its power plants. This same commitment will be applied in 2003 and future years. Unexpected plant outages may, however, require purchases at market prices to enable TransCanada to meet the company's contractual power supply obligations.

Fluctuating Market Prices TransCanada operates in highly competitive markets that are driven mainly by price. Volatility in electricity prices is caused by market factors such as power plant fuel costs and fluctuating supply and demand which are greatly affected by weather, consumer usage and plant availability. These inherent market risks are managed through the use of long-term purchase and sales contracts for both electricity and plant fuels, control over generation output, matching physical plant contracts or PPA supply with customer demand, fee-for-service managed accounts rather than direct commodity exposure, and TransCanada's overall risk management program with respect to general market and counterparty risks. The company's risk management practices are described in the section on Risk Management and in Note 13 to the Consolidated Financial Statements.

Regulatory As the electricity markets evolve across North America, there is the potential for regulatory bodies to implement new rules that could negatively impact TransCanada as a generator and as a marketer. These may be in the form of price caps or attempts to control the wholesale market by encouraging new plant construction. TransCanada continues to monitor regulatory issues as well as participate in and lead discussions around these topics.

Weather Demand fluctuations caused by changes in temperature and weather patterns may create power price volatility and may have an earnings impact due to TransCanada's requirements under certain long-term supply arrangements. Seasonal changes in temperature also affect the efficiency and output capability of natural gas-fired power plants. In addition, the seasonality of water flows on the Hudson River impacts the output and related earnings from the Curtis Palmer hydroelectric facility.

Uncontracted Volumes Although TransCanada seeks to secure sales under medium- to long-term contracts, TransCanada generally retains a small amount of unsold generation in the short term in order to provide flexibility in managing the portfolio of assets. The potential sale of this power in the open market is subject to market price volatility. Through the use of PPAs and other marketing arrangements, TransCanada has sold almost all of its expected power supply in 2003 and 70 to 80 per cent for the years 2004 to 2006.

Corporate

HIGHLIGHTS

Lower Net Expenses Net expenses in 2002 decreased $15 million or 22 per cent from 2001.

Cost Reductions In 2002, the company continued to reduce general and administrative costs related to discontinued operations.

CORPORATE RESULTS-AT-A-GLANCE

Year ended December 31	**2002**	2001	2000
(millions of dollars)			
General and administrative costs related to discontinued operations	**4**	13	18
Indirect financial and preferred equity charges	**64**	62	111
Interest income and other	**(16)**	(8)	(49)
Net expenses, after tax	**52**	67	80

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

- *General and Administrative Costs Related to Discontinued Operations* Corporate overhead costs related to discontinued operations remain in the Corporate segment.
- *Indirect Financial and Preferred Equity Charges* Direct financial charges are reported in their respective business segments and are primarily associated with the debt and preferred securities related to the 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.

Net expenses, after tax, in the Corporate segment, were $52 million in 2002 compared to $67 million in 2001 and $80 million in 2000.

The decrease in 2002 from 2001 is primarily due to lower general and administrative expenses to support discontinued operations and the positive impact of lower interest rates offset by increased Corporate financial charges resulting from the Fair Return decision. The decrease in 2001 from 2000 is primarily due to lower financial and preferred equity charges as a result of lower net debt balances and the redemption of preferred securities, partially offset by tax recoveries of $28 million recorded in 2000 to reflect the impact of tax law and income tax rate changes. Financial charges in 2001 reflect a full year's impact of the 2000 debt reductions as well as additional debt reductions in 2001.

Results for 2001 and 2000 included an adjustment of $5 million and $(2) million to foreign currency gains/(losses), respectively, reflecting the January 1, 2002 required retroactive adoption of an accounting change issued by the Canadian Institute of Chartered Accountants (CICA) related to foreign currency translation. There was no impact as a result of this accounting change in 2002.

Liquidity and Capital Resources

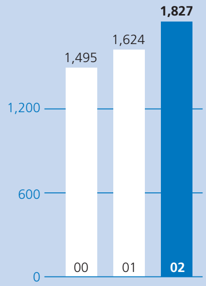
HIGHLIGHTS

Funds Flow Increase Funds generated from continuing operations increased $203 million or 13 per cent in 2002 compared to 2001.

Sustained Growth Total capital expenditures including acquisitions have exceeded $3.0 billion over the past three years.

Debt Reduction The company's repayment of long-term debt and redemption of preferred shares and securities has exceeded $4.0 billion over the past three years.

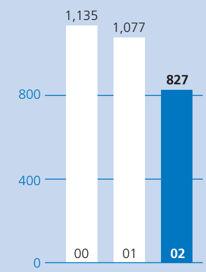
Dividend Increase TransCanada's Board of Directors has increased quarterly common share dividend payments for the past three consecutive years, including an eight per cent increase from $0.25 to $0.27 for the quarter ended March 31, 2003.



FUNDS GENERATED FROM CONTINUING OPERATIONS
(millions of dollars)

Funds Generated from Operations Funds generated from continuing operations were $1.8 billion for the year ended December 31, 2002 compared with $1.6 billion and $1.5 billion for 2001 and 2000, respectively. The Transmission business was the primary source of funds generated from operations for each of the three years.

The company also reduced long-term debt, preferred shares and 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, 2002 as in the past few years.

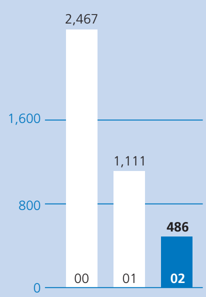


CAPITAL EXPENDITURES INCLUDING ACQUISITIONS
(millions of dollars)

Investing Activities Capital expenditures, excluding acquisitions, totalled $599 million in 2002 compared to $492 million and $812 million in 2001 and 2000, respectively. Expenditures in all three years related primarily to maintenance and capacity capital in TransCanada's Transmission business and construction of new power plants in Alberta.

During 2002, TransCanada acquired the ManChief power plant for $209 million and a general partnership interest in NBPLP for $19 million. During 2001, TransCanada acquired the Curtis Palmer Hydroelectric Company, L.P. for $438 million, and through a partnership, effectively acquired 50 per cent of the rights and obligations of the 706 MW Sundance B PPA for $110 million.

TransCanada's 2001 and 2000 investing activities also include proceeds of $1.17 billion and $2.23 billion, respectively, from the sale of non-core assets under the company's divestiture plans.



LONG-TERM DEBT REPAID AND PREFERRED SHARES AND SECURITIES REDEEMED
(millions of dollars)

Financing Activities TransCanada used a portion of its cash resources to repay debt maturities of $486 million and reduce notes payable by $46 million in 2002 and repay debt maturities of $793 million and redeem preferred securities of $318 million in 2001. In 2001, TransCanada increased notes payable by $186 million. In 2000, TransCanada used proceeds on disposition of assets, together with cash flow from operations, to repurchase or redeem approximately $2.5 billion in long-term debt and preferred shares and reduce notes payable by $25 million. Dividends and preferred securities charges amounting to $546 million were paid in 2002 compared to $517 million and $536 million in 2001 and 2000, respectively.

In January 2003, TransCanada's Board of Directors approved an increase in the quarterly common share dividend payment from $0.25 per share to $0.27 per share for the quarter ended March 31, 2003. This was the third consecutive year of dividend increase. In January 2002, TransCanada's Board of Directors approved an increase in the quarterly common share dividend payment from $0.225 per share to $0.25 per share for the quarter ended March 31, 2002. In January 2001, TransCanada's Board of Directors approved an increase from $0.20 per share to $0.225 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 $36 million in 2002 compared to $109 million in 2001. Net cash provided by non-recourse joint venture debt activities was $122 million in 2000.

Credit Activities In 2002, TransCanada filed shelf prospectuses in Canada and the U.S. qualifying for issuance $2 billion of common shares, preferred shares and/or debt securities including medium-term notes and US$1 billion of common shares, preferred shares and/or debt securities, respectively. Any offer to sell securities under these shelf prospectuses will only be made by means of prospectus supplements filed with the appropriate securities regulatory authorities.

In December 2002, TransCanada established a new $1.5 billion syndicated credit facility, replacing existing lines set to expire in mid-2003. The new 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.

At December 31, 2002, TransCanada had total credit facilities of $2.0 billion which support the company's commercial paper program and general corporate purposes. At December 31, 2002, the company had used approximately $269 million of its total lines of credit for letters of credit to support its ongoing commercial arrangements.

Credit ratings on the company'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. On December 23, 2002, Standard & Poor's placed its rating of TransCanada's senior unsecured debt on 'CreditWatch' with negative implications. DBRS and Moody's continue to maintain a 'stable' outlook.

Obligations and Commitments Total long-term debt at December 31, 2002 was $9.3 billion compared to $9.8 billion at December 31, 2001. TransCanada's share of total non-recourse debt of joint ventures at December 31, 2002 was $1.3 billion, consistent with the prior year-end. Total notes payable, including those of joint ventures, at December 31, 2002 were $297 million compared to $343 million at December 31, 2001. 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, 2002, mandatory retirements resulting from maturities and sinking fund obligations related to long-term debt and the company's proportionate share of the non-recourse debt of joint ventures are as follows.

MANDATORY RETIREMENTS

Year ended December 31	2003	2004	2005	2006	2007	2008+
(millions of dollars)						
Long-term debt	517	386	375	453	621	6,980
Non-recourse debt of joint ventures	75	42	462	26	24	668
Total retirements	592	428	837	479	645	7,648

At December 31, 2002, future annual payments, net of sub-lease receipts, for the next five years under operating leases for various premises are approximately as follows.

OPERATING LEASE PAYMENTS

Year ended December 31	2003	2004	2005	2006	2007
(millions of dollars)					
Minimum lease payments	27	25	25	24	22
Amounts recoverable under sub-leases	(9)	(7)	(7)	(7)	(6)
Net payments	18	18	18	17	16

The company will fund its pension plans during 2003 in an amount that is expected to be approximately double the $54 million contributed during 2002. This increased funding is due to investment performance in 2002 below long-term expectations, continued reductions in discount rates used to calculate plan liabilities, and one-time plan design changes.

At December 31, 2002, 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). The Redemption Price will be satisfied by TransCanada in cash or, at the election of TransCanada, in common shares of TransCanada or a combination of cash and common shares.

TransCanada has established a $50 million operating line of credit to Power LP, available on a revolving basis. As at December 31, 2002, the amount borrowed against this line of credit was $37 million compared to $16 million at December 31, 2001.

At December 31, 2002, TransCanada held a 33.4 per cent interest in TC PipeLines, LP which is a publicly-held limited partnership. On May 28, 2001, TC PipeLines, LP renewed its $40 million unsecured two-year revolving credit facility (TransCanada Credit Facility) with a subsidiary of TransCanada. At December 31, 2002 and 2001, the partnership had no amount outstanding under the TransCanada Credit Facility.

The company had no outstanding guarantees related to the long-term debt of unrelated third parties at December 31, 2002. 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.

TransCanada has guaranteed the equity undertaking of a subsidiary which supports the payment of debt obligations of TransGas, in the event a change of law would result in insufficient funds in TransGas to pay the interest and principal on its public US$206 million debt obligations. The company has an indirect 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 its 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 shares 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.

Upon the acquisition of Bruce Power L.P., the Consortium members guaranteed on a several, pro-rata basis certain contingent financial obligations of Bruce Power L.P. related to operator licences, the lease agreement, power sales agreements and contractor services. TransCanada's share of the net exposure under these guarantees at the time of closing was estimated to be approximately $260 million.

Contingencies The California Attorney General has filed a complaint for civil penalties in California Superior Court under the California Business and Professions Code.

The complaint alleges that certain TransCanada subsidiaries and affiliates engaged in sales or purchases of electricity in California for which they failed to comply with the filing requirements of the Federal Power Act and FERC orders. TransCanada believes the actions of its subsidiaries and affiliates were in compliance with the Federal Power Act and FERC requirements. TransCanada considers the complaint to be without merit and is vigorously defending it. The company has made no provision for any potential liability.

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 their resolution will not have a material impact on the company's consolidated financial position or results of operations.

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 Board of Directors' review and approval.
- *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* Risk profiles of counterparties are subjected 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 and Risk Management Committee of the 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 its business objectives and risk tolerance. Risks are managed within limits ultimately established by the 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 its corporate market risk policy and position limits. The company's primary market risks result from volatility in commodity prices, interest rates, foreign currency exchange rates and the failure of counterparties to meet contractual financial obligations.

Senior management reviews these exposures and reports to the Audit and Risk Management Committee of the Board of Directors regularly.

Power Marketing Price 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 its investments in foreign currency denominated net assets, its regulated and non-regulated long-term debt portfolios and its 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.

The company's financial risk management practices are further described under Foreign Exchange and Interest Rate Management Activity in Note 13 to the Consolidated Financial Statements.

Counterparty Risk Management Counterparty risk entails a counterparty's ability to meet its obligations in a timely manner as outlined under the terms and conditions of its contracts. 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 13 to the Consolidated Financial Statements.

Risks and Risk Management Related to the Kyoto Protocol Once the details of the Canadian government's implementation plans with respect to the Kyoto Protocol are clarified, TransCanada will be better able to assess the degree of impact to the company's business. Anything that adds costs to the company's services and products makes TransCanada less competitive. Studies suggest there could be a significant drop in WCSB oil and gas activity, thereby reducing throughputs on the company's pipeline system and substantially increasing the costs of doing business.

Over the past few years, working in partnership with energy producers and consumers on a voluntary basis, TransCanada's focus has been, and continues to be, on developing options for reducing greenhouse gas (GHG) emissions. This is being achieved through technical and operational improvements, driven in large part by improved fuel efficiency, cleaner combustion 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) and internal controls for financial reporting (internal controls). This evaluation is done under the supervision of, and with the participation of, the Chief Executive Officer and the Chief Financial Officer.

Disclosure controls are procedures designed to ensure that information required to be disclosed in reports filed with securities regulatory agencies is recorded, processed, summarized and reported on a timely basis, and that TransCanada's management, including the Chief Executive Officer and the Chief Financial Officer, can make timely decisions utilizing such information. Internal controls are procedures designed to provide reasonable assurance that transactions are properly authorized, assets are safeguarded against unauthorized or improper use, and transactions are properly recorded and reported. The risk management controls provide significant support to the disclosure and internal controls.

Within 90 days prior to the filing of this Annual Report, TransCanada's management evaluated the effectiveness of disclosure controls and internal controls. Based on that evaluation, the 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;
- TransCanada's internal controls are effective in providing assurance that the consolidated financial statements for 2002 are fairly presented.

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. 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 14 and Note 8, 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 remains contingently liable pursuant to obligations under certain contracts that relate to the divested Gas Marketing business. In 2001, the company deferred recognition of after-tax gains on sales of approximately $100 million which remain in the December 31, 2002 balance sheet provision for loss on discontinued operations. The company uses estimates to determine its exposure to these contracts. These estimates primarily relate to future market prices. This obligation is further described in Discontinued Operations.

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, 2002 was $848 million. Depreciation expense impacts the Transmission and Power segments of the company. In the 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 Transmission segment would therefore have no material impact on TransCanada's net income but would directly impact the funds generated from operations.

ACCOUNTING CHANGES

Price Risk Management In 2002, the company adopted accrual accounting for energy trading contracts in its continuing operations, changing from its previous policy of mark-to-market accounting for these contracts. This accounting change has been applied retroactively with restatement of prior periods. This change eliminates unrealized gains and losses on energy trading contracts recognized under mark-to-market accounting. See Note 2 to the Consolidated Financial Statements for the impact of this accounting change.

Foreign Currency Translation In 2002, TransCanada adopted the amendment to the CICA Handbook Section "Foreign Currency Translation". This amendment eliminates the deferral and amortization of unrealized translation gains and losses on foreign currency denominated monetary items that have a fixed or ascertainable life extending beyond the end of the fiscal year following the current reporting period. This accounting change was applied retroactively with restatement of prior periods. See Note 2 to the Consolidated Financial Statements for the impact of this accounting change.

Stock-Based Compensation In 2002, TransCanada adopted the new standard of the CICA Handbook Section "Stock-Based Compensation and Other Stock-Based Payments". This section establishes standards for the recognition, measurement and disclosure of stock-based compensation and other stock-based payments made in exchange for goods and services. It applies to transactions in which an enterprise grants shares of common stock, stock options, or other equity instruments, or incurs liabilities based on the price of common stock or other equity instruments. This standard allows companies to either expense, over the vesting period, the fair value of the stock options granted or to disclose this impact. The company has chosen to expense stock options. This new standard has been applied prospectively. See Note 2 to the Consolidated Financial Statements for the impact of this accounting change.

Disclosure of Guarantees In 2002, TransCanada adopted the new Accounting Guideline "Disclosure of Guarantees" issued by the Accounting Standards Board of the CICA that requires a guarantor to disclose significant information about guarantees it has provided, without regard to whether it will have to make any payments under the guarantees. See Note 18 to the Consolidated Financial Statements.

Hedging Relationships In November 2001, the Accounting Standards Board of the CICA issued an Accounting Guideline "Hedging Relationships" that establishes standards for the documentation and effectiveness of hedging relationships. These standards 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. The company does not expect the new Canadian requirement to have a significant impact on its 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 will be effective for the company on a prospective basis after May 1, 2003 and will not result in restatement of income for prior periods.

Impairment on Long-Lived Assets In November 2002, the CICA issued a new Handbook Section "Impairment on 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 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 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 financial statements.

Discontinued Operations

FINANCIAL REVIEW

In July 2001, the Board of Directors approved a plan to dispose of the company's Gas Marketing business. The Gas Marketing business provided supply, transportation and asset management services, as well as structured financial products and services, to its customers in Canada and the northern tier of the U.S. In December 1999, the Board of Directors approved a plan (December Plan) to dispose of the company's International, Canadian midstream and certain other businesses.

These businesses are accounted for as discontinued operations. The net income/(loss) and cash provided from/(used in) operations are presented as discontinued operations in the Consolidated Statements of Income and Cash Flows. The net assets of discontinued operations included in the Consolidated Balance Sheet are disclosed separately in Note 19 to the Consolidated Financial Statements.

The company's net income/(loss) from discontinued operations in 2002 is nil as the existing provision for loss on discontinued operations was reviewed by management and determined to be appropriate. Any adjustments to the estimate of the net loss on disposal will be recognized as a gain or loss from discontinued operations in the period that such changes are determined.

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.

The company recorded a net gain from discontinued operations in 2000 of $61 million. This amount includes operating losses of $139 million related to the Gas Marketing business prior to plan approval and a net gain of $200 million related to the December Plan, primarily due to proceeds in excess of the original estimate.

TransCanada remains contingently liable pursuant to obligations under certain contracts that relate to the divested Gas Marketing business. In 2001, the company deferred recognition of after-tax gains on sales of approximately $100 million. These deferred gains remain in the December 31, 2002 balance sheet provision for loss on discontinued operations and will be recognized in income from discontinued operations as the underlying exposures reduce. In accordance with the terms of these contracts and in the normal course of business, the underlying volumes related to the contracts are expected to decrease over time. The contingent liability under these obligations, which could be significant, is contingent on certain future events, the occurrence of which is not determinable, and the amount, if any, is dependent upon future prevailing market prices and conditions. 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 QUARTERLY CONSOLIDATED FINANCIAL DATA

Quarterly consolidated financial data for the years ended December 31, 2002 and 2001 is found under the heading "Selected Quarterly and Annual Consolidated Financial Data" on page 78 in the Annual Report and is hereby incorporated by reference.

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.

2002 CONSOLIDATED FINANCIAL STATEMENTS
REPORT OF MANAGEMENT

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

Management has prepared Management's Discussion and Analysis (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 2002 to 2001 and should be read in conjunction with the consolidated financial statements and accompanying notes. In addition, significant changes between 2001 and 2000 are highlighted. Note 20 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 and Risk Management Committee consisting of unrelated, non-management directors which meets at least four 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 and Risk Management 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 and Risk Management Committee without obtaining prior Management approval.

With respect to the external auditors, KPMG LLP, the Audit and Risk Management 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 48 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
and Chief Financial Officer

February 25, 2003

CONSOLIDATED INCOME

Year ended December 31	2002	2001	2000
(millions of dollars except per share amounts)			
Revenues	**5,214**	5,275	4,384
Operating Expenses			
Cost of sales	**627**	712	133
Other costs and expenses	**1,546**	1,618	1,539
Depreciation	**848**	793	737
	3,021	3,123	2,409
Operating Income	**2,193**	2,152	1,975
Other Expenses/(Income)			
Financial charges *(Note 8)*	**867**	889	953
Financial charges of joint ventures *(Note 9)*	**90**	107	113
Interest and other income	**(86)**	(77)	(115)
Gain on sale of assets	**–**	–	(37)
	871	919	914
Income from Continuing Operations before Income Taxes	**1,322**	1,233	1,061
Income Taxes *(Note 14)*	**517**	480	354
Net Income from Continuing Operations	**805**	753	707
Net (Loss)/Income from Discontinued Operations *(Note 19)*	**–**	(67)	61
Net Income	**805**	686	768
Preferred Securities Charges *(Note 10)*	**36**	45	44
Preferred Share Dividends	**22**	22	35
Net Income Applicable to Common Shares	**747**	619	689
Net Income/(Loss) Applicable to Common Shares			
Continuing operations	**747**	686	628
Discontinued operations	**–**	(67)	61
	747	619	689
Net Income/(Loss) Per Share *(Note 12)*			
Continuing operations	**$ 1.56**	$ 1.44	$ 1.32
Discontinued operations	**–**	(0.14)	0.13
Basic	**$ 1.56**	$ 1.30	$ 1.45
Diluted	**$ 1.55**	$ 1.30	$ 1.45

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

CONSOLIDATED CASH FLOWS

Year ended December 31	2002	2001	2000
(millions of dollars)			
Cash Generated from Operations			
Net income from continuing operations	**805**	753	707
Depreciation	**848**	793	737
Future income taxes	**247**	127	74
Gain on sale of assets	**–**	–	(37)
Other	**(73)**	(49)	14
Funds generated from continuing operations	**1,827**	1,624	1,495
Decrease/(increase) in operating working capital *(Note 17)*	**33**	170	(416)
Net cash provided by continuing operations	**1,860**	1,794	1,079
Net cash provided by/(used in) discontinued operations	**59**	(659)	853
	1,919	1,135	1,932
Investing Activities			
Capital expenditures	**(599)**	(492)	(812)
Acquisitions, net of cash acquired	**(228)**	(585)	(323)
Disposition of assets	**–**	1,170	2,233
Deferred amounts and other	**(115)**	30	(31)
Net cash (used in)/provided by investing activities	**(942)**	123	1,067
Financing Activities			
Dividends and preferred securities charges	**(546)**	(517)	(536)
Notes payable (repaid)/issued, net	**(46)**	186	(25)
Reduction of long-term debt	**(486)**	(793)	(2,139)
Non-recourse debt of joint ventures issued	**44**	23	404
Reduction of non-recourse debt of joint ventures	**(80)**	(132)	(282)
Common shares issued	**50**	24	5
Partnership units of joint ventures issued	**–**	59	–
Preferred securities redeemed	**–**	(318)	–
Preferred shares redeemed	**–**	–	(328)
Net cash used in financing activities	**(1,064)**	(1,468)	(2,901)
(Decrease)/Increase in Cash and Short-Term Investments	**(87)**	(210)	98
Cash and Short-Term Investments			
Beginning of year	**299**	509	411
Cash and Short-Term Investments			
End of year	**212**	299	509

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

CONSOLIDATED BALANCE SHEET

December 31	2002	2001
(millions of dollars)		
ASSETS		
Current Assets		
Cash and short-term investments	**212**	299
Accounts receivable	**691**	655
Inventories	**178**	177
Other	**102**	43
	1,183	1,174
Long-Term Investments *(Note 7)*	**291**	268
Plant, Property and Equipment *(Notes 4, 8 and 9)*	**17,496**	17,685
Other Assets *(Note 5)*	**946**	827
	19,916	19,954
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable *(Note 15)*	**297**	343
Accounts payable	**902**	786
Accrued interest	**227**	233
Current portion of long-term debt *(Note 8)*	**517**	483
Current portion of non-recourse debt of joint ventures *(Note 9)*	**75**	44
Provision for loss on discontinued operations *(Note 19)*	**234**	264
	2,252	2,153
Deferred Amounts	**353**	393
Long-Term Debt *(Note 8)*	**8,815**	9,347
Future Income Taxes *(Note 14)*	**226**	39
Non-Recourse Debt of Joint Ventures *(Note 9)*	**1,222**	1,295
Junior Subordinated Debentures *(Note 10)*	**238**	237
	13,106	13,464
Shareholders' Equity		
Preferred securities *(Note 10)*	**674**	675
Preferred shares *(Note 11)*	**389**	389
Common shares *(Note 12)*	**4,614**	4,564
Contributed surplus	**265**	263
Retained earnings	**854**	586
Foreign exchange adjustment *(Note 13)*	**14**	13
	6,810	6,490
Commitments, Contingencies and Guarantees *(Note 18)*		
Subsequent Event *(Note 21)*		
	19,916	19,954

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	**2002**	2001	2000
(millions of dollars)			
Balance at beginning of year	**586**	395	85
Net income	**805**	686	768
Preferred securities charges	**(36)**	(45)	(44)
Preferred share dividends	**(22)**	(22)	(35)
Common share dividends	**(479)**	(428)	(379)
	854	586	395

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

AUDITORS' REPORT

To the Shareholders of TransCanada PipeLines Limited

We have audited the consolidated balance sheets of TransCanada PipeLines Limited as at December 31, 2002 and 2001 and the consolidated statements of income, retained earnings and cash flows for each of the years in the three-year period ended December 31, 2002. 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, 2002 and 2001 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2002 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada

February 25, 2003

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

TRANSMISSION

The Transmission business 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) and a natural gas transmission system extending from the Alberta border west into southeastern British Columbia (the BC System). It also holds the Company's investments in other natural gas pipelines in Canada and the United States, and investigates and develops new natural gas transmission facilities in Canada and the United States.

POWER

The Power business builds, owns and operates electrical power plants, and markets electricity. This business operates in both Canada and the United States.

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 20. Amounts are stated in Canadian dollars unless otherwise indicated. Certain comparative figures have been reclassified to conform with the current year's presentation.

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

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

Regulation The Alberta System is regulated by the Alberta Energy and Utilities Board (EUB), and the Canadian Mainline and the BC System 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 June 2002, the Company received the 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 final tolls on the Canadian Mainline. The Fair Return decision on the cost of capital included an increase in the deemed common equity ratio from 30 to 33 per cent effective January 1, 2001. The NEB also decided that the return on equity as calculated based on the NEB formula continued to be appropriate for the Canadian Mainline which results in an approved rate of return on common equity of 9.61 per cent for 2001 and 9.53 per cent for 2002. 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.

Plant, Property and Equipment

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 and when approved by the regulators. 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 and Other 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. Other 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 four 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. PPAs are included in Other Assets.

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 and Canadian Mainline 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 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 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. In addition to the defined benefit plan, 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.

NOTE 2 Accounting Changes

Price Risk Management In 2002, the Company adopted accrual accounting for energy trading contracts in its continuing operations, changing from its previous policy of mark-to-market accounting for these contracts. This accounting change has been applied retroactively with restatement of prior periods. This change eliminates unrealized gains and losses on energy trading contracts recognized under mark-to-market accounting. The cumulative effect of this accounting change as at January 1, 2000 was nil. The impact of this change on net income for the years ended December 31, 2001 and December 31, 2000 was an increase of $11 million ($0.02 per share) and a decrease of $20 million ($0.04 per share), respectively, which is reflected in the Power segment. Under accrual accounting, net income for the year ended December 31, 2002 is $13 million ($0.03 per share) higher than would have been reported under mark-to-market accounting.

Foreign Currency Translation In 2002, the Company adopted the amendment to the Canadian Institute of Chartered Accountants (CICA) Handbook Section "Foreign Currency Translation". This amendment eliminates the deferral and amortization of unrealized translation gains and losses on foreign currency denominated monetary items that have a fixed or ascertainable life extending beyond the end of the fiscal year following the current reporting period. This accounting change was applied retroactively with restatement of prior periods. The cumulative effect of this accounting change as at January 1, 2000 was an increase of $3 million in retained earnings. The impact of this change on net income for the years ended December 31, 2001 and December 31, 2000 was an increase of $5 million ($0.01 per share) and a decrease of $2 million ($0.01 per share), respectively, which is reflected in the Corporate segment. This change had no impact on net income for the year ended December 31, 2002.

Stock-Based Compensation In 2002, the Company adopted the new standard of the CICA Handbook Section "Stock-Based Compensation and Other Stock-Based Payments". This section establishes standards for the recognition, measurement and disclosure of stock-based compensation and other stock-based payments made in exchange for goods and services. It applies to transactions in which an enterprise grants shares of common stock, stock options, or other equity instruments, or incurs liabilities based on the price of common stock or other equity instruments. This standard allows companies to either expense, over the vesting period, the fair value of the stock options granted or to disclose this impact. This new standard has been applied prospectively.

The Company has chosen to expense stock options and the impact of this accounting change, which has been recorded in 2002, results in a $2 million charge to net income. This charge is reflected in the Transmission and Power segments. The Company used the Black-Scholes model for this calculation with the weighted average assumptions being 5 years of expected life, 4.7 per cent interest rate, 18 per cent volatility and 4.7 per cent dividend yield.

The impacts of the accounting changes on the Consolidated Balance Sheet, Consolidated Statement of Income and Consolidated Statement of Cash Flows as at and for the years ended December 31, 2001 and December 31, 2000, respectively, are as follows.

	Increase/(Decrease)	
	2001	2000
(millions of dollars)		
Consolidated Balance Sheet		
Energy trading assets		
Current asset	(152)	(582)
Long-term asset	(365)	(379)
Other assets	322	215
Future income tax asset	–	15
Total assets	(195)	(731)
Energy trading liabilities		
Current liability	(72)	(542)
Long-term liability	(112)	(170)
Future income tax liability	(8)	–
Total liabilities	(192)	(712)
Retained earnings	(3)	(19)
Consolidated Income		
Revenues	26	(37)
Operating expenses	9	–
Financial charges	(6)	2
Income taxes – current and future	7	(17)
Net income	16	(22)
Consolidated Cash Flows		
Funds generated from continuing operations	110	212
Net cash used in investing activities	(110)	(212)

NOTE 3 Segmented Information

Net Income/(Loss) [1]

Year ended December 31, 2002	Transmission	Power	Corporate	Total
(millions of dollars)				
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 and preferred equity charges	**(821)**	**(13)**	**(91)**	**(925)**
Financial charges of joint ventures	**(90)**	**–**	**–**	**(90)**
Interest and other income	**50**	**13**	**23**	**86**
Income taxes	**(458)**	**(84)**	**25**	**(517)**
Continuing Operations	**653**	**146**	**(52)**	**747**
Discontinued Operations				**–**
Net Income Applicable to Common Shares				**747**

Year ended December 31, 2001	Transmission	Power	Corporate	Total
(millions of dollars)				
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 and preferred equity charges	(856)	(15)	(85)	(956)
Financial charges of joint ventures	(98)	(9)	–	(107)
Interest and other income	30	13	34	77
Income taxes	(392)	(106)	18	(480)
Continuing Operations	585	168	(67)	686
Discontinued Operations				(67)
Net Income Applicable to Common Shares				619

Year ended December 31, 2000	Transmission	Power	Corporate	Total
(millions of dollars)				
Revenues	3,856	528	–	4,384
Cost of sales [2]	–	(133)	–	(133)
Other costs and expenses	(1,252)	(256)	(31)	(1,539)
Depreciation	(698)	(35)	(4)	(737)
Operating income/(loss)	1,906	104	(35)	1,975
Financial and preferred equity charges	(877)	(3)	(152)	(1,032)
Financial charges of joint ventures	(101)	(12)	–	(113)
Interest and other income	52	9	54	115
Gain on sale of assets	11	26	–	37
Income taxes	(368)	(39)	53	(354)
Continuing Operations	623	85	(80)	628
Discontinued Operations				61
Net Income Applicable to Common Shares				689

(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 include commodity purchases for resale.

Total Assets

December 31	2002	2001
(millions of dollars)		
Transmission	**16,979**	17,269
Power	**2,292**	1,880
Corporate	**457**	480
Continuing Operations	**19,728**	19,629
Discontinued Operations	**188**	325
	19,916	19,954

Geographic Information

Year ended December 31	2002	2001	2000
(millions of dollars)			
Revenues (3)			
Canada – domestic	**2,731**	3,303	2,765
Canada – export	**1,641**	1,329	1,120
United States	**842**	643	499
	5,214	5,275	4,384

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

Plant, Property and Equipment

December 31	2002	2001
(millions of dollars)		
Canada	**15,479**	15,752
United States	**2,017**	1,933
	17,496	17,685

Capital Expenditures

Year ended December 31	2002	2001	2000
(millions of dollars)			
Transmission	**382**	285	354
Power	**193**	121	104
Corporate	**11**	34	60
Continuing Operations	**586**	440	518
Discontinued Operations	**13**	52	294
	599	492	812

NOTE 4 Plant, Property and Equipment

December 31	2002			2001		
	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
(millions of dollars)						
Transmission						
Alberta System						
Pipeline	**4,922**	**1,755**	**3,167**	4,810	1,607	3,203
Compression	**1,517**	**479**	**1,038**	1,489	413	1,076
Metering and other	**919**	**237**	**682**	964	258	706
	7,358	**2,471**	**4,887**	7,263	2,278	4,985
Under construction	**4**	**–**	**4**	33	–	33
	7,362	**2,471**	**4,891**	7,296	2,278	5,018
Canadian Mainline						
Pipeline	**8,674**	**2,933**	**5,741**	8,659	2,708	5,951
Compression	**3,291**	**709**	**2,582**	3,400	738	2,662
Metering and other	**429**	**118**	**311**	444	124	320
	12,394	**3,760**	**8,634**	12,503	3,570	8,933
Under construction	**15**	**–**	**15**	21	–	21
	12,409	**3,760**	**8,649**	12,524	3,570	8,954
North American Pipelines and Other						
Pipelines	**4,070**	**1,573**	**2,497**	3,942	1,472	2,470
Other	**121**	**60**	**61**	120	53	67
	4,191	**1,633**	**2,558**	4,062	1,525	2,537
	23,962	**7,864**	**16,098**	23,882	7,373	16,509
Power						
Power generation facilities	**1,693**	**398**	**1,295**	1,432	365	1,067
Other	**77**	**38**	**39**	77	34	43
	1,770	**436**	**1,334**	1,509	399	1,110
Corporate	**120**	**56**	**64**	114	48	66
	25,852	**8,356**	**17,496**	25,505	7,820	17,685

NOTE 5 Other Assets

December 31	2002	2001
(millions of dollars)		
Power purchase arrangements – Canada	**297**	314
Power purchase arrangements – U.S.	**325**	221
Discontinued operations	**103**	200
Other	**221**	92
	946	827

Amortization expense with respect to the PPAs was $28 million for the year ended December 31, 2002 (2001 – $18 million; 2000 – nil). At December 31, 2002, the accumulated amortization for the PPAs – Canada and the PPAs – U.S. was $32 million and $14 million, respectively (December 31, 2001 – $14 million and $4 million, respectively). In 2002, the Company acquired $114 million of PPAs – U.S. In 2001, the Company acquired $110 million of PPAs – Canada and $225 million of PPAs – U.S.

NOTE 6 Joint Venture Investments

		TransCanada's Proportionate Share				
		Income Before Income Taxes Year ended December 31			Net Assets December 31	
	Ownership Interest	**2002**	2001	2000	**2002**	2001
(millions of dollars)						
Transmission						
Great Lakes	50.0%	**102**	89	84	**492**	473
Iroquois	41.0%(1)	**30**	27	22	**160**	132
Foothills	50.0-74.5%	**29**	26	33	**204**	215
TC PipeLines, LP	33.4%	**24**	23	5	**158**	136
Trans Québec & Maritimes	50.0%	**13**	15	14	**79**	80
CrossAlta	60.0%	**21**	15	11	**35**	22
Other	Various	**7**	4	4	**17**	18
Power						
TransCanada Power, L.P.	35.6%(2)	**26**	21	21	**244**	253
ASTC Power Partnership	50.0%(3)	**–**	–	–	**105**	118
Ocean State Power	(4)	**–**	–	22	**–**	–
		252	220	216	**1,494**	1,447

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

(2) During 2000, the Company increased its interest in TransCanada Power, L.P. from 32.7 per cent to 41.6 per cent and in October 2001, decreased its interest to 35.6 per cent.

(3) 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.

(4) In October 2000, the Company increased its interest in the Ocean State Power plant from 70.1 per cent to 100 per cent and the investment was consolidated subsequent to that date.

Consolidated retained earnings at December 31, 2002 include undistributed earnings from these joint ventures of $433 million (2001 – $347 million).

Summarized Financial Information of Joint Ventures

Year ended December 31	**2002**	2001	2000
(millions of dollars)			
Income			
Revenues	**680**	592	603
Other costs and expenses	**(251)**	(172)	(155)
Depreciation	**(119)**	(119)	(132)
Financial charges and other	**(58)**	(81)	(100)
Proportionate share of income before income taxes of joint ventures	**252**	220	216

Year ended December 31	**2002**	2001	2000
(millions of dollars)			
Cash Flows			
Operations	**323**	279	321
Investing activities	**(125)**	21	(80)
Financing activities	**(210)**	(291)	(240)
Proportionate share of (decrease)/increase in cash and short-term investments of joint ventures	**(12)**	9	1

December 31	2002	2001
(millions of dollars)		
Balance Sheet		
Cash and short-term investments	**63**	75
Other current assets	**127**	92
Long-term investments	**148**	132
Plant, property and equipment	**2,503**	2,490
Other assets and deferred amounts (net)	**103**	135
Current liabilities	**(164)**	(118)
Non-recourse debt	**(1,222)**	(1,295)
Future income taxes	**(64)**	(64)
Proportionate share of net assets of joint ventures	**1,494**	1,447

The Company is charged for gas transmission by certain of the Transmission joint ventures. These charges are at rates approved by regulators and the Company's proportionate share is eliminated within the Transmission segment.

NOTE 7 Long-Term Investments

December 31	2002	2001
(millions of dollars)		
Equity Investments		
Northern Border	**129**	132
TransGas	**75**	70
Portland	**68**	66
Other	**19**	–
	291	268

The Northern Border equity investment (Northern Border) 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. The Company holds a 33.3 per cent interest in Portland Natural Gas Transmission System Partnership (Portland) and a 46.5 per cent interest in TransGas de Occidente S.A. (TransGas). Consolidated retained earnings at December 31, 2002 include undistributed earnings from these equity investments of $44 million (2001 – $40 million).

Income from these equity investments for the year ended December 31, 2002 was $34 million (2001 – $25 million; 2000 – $28 million).

NOTE 8 Long-Term Debt

		2002		2001	
	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	2003 to 2024	**798**	**11.0%**	819	11.0%
U.S. dollars (2002 – US$500; 2001 – US$625)	2004 to 2023	**790**	**8.3%**	995	8.2%
Medium-Term Notes					
Canadian dollars	2005 to 2030	**767**	**7.4%**	774	7.4%
U.S. dollars (2002 and 2001 – US$233)	2026 to 2029	**368**	**7.7%**	371	7.7%
Unsecured Loans					
U.S. dollars (2002 and 2001 – US$107)	2003	**169**	**2.1%**	170	2.3%
		2,892		3,129	
Foreign exchange differential recoverable through the tollmaking process		**(271)**		(322)	
		2,621		2,807	
Canadian Mainline					
First Mortgage Pipe Line Bonds					
Pounds Sterling (2002 and 2001 – £25)	2007	**64**	**16.5%**	58	16.5%
Debentures					
Canadian dollars	2008 to 2020	**1,354**	**10.9%**	1,455	10.9%
U.S. dollars (2002 and 2001 – US$800)	2012 to 2023	**1,264**	**9.2%**	1,274	9.2%
Medium-Term Notes					
Canadian dollars	2003 to 2031	**2,405**	**7.0%**	2,585	7.1%
U.S. dollars (2002 and 2001 – US$120)	2010	**190**	**6.1%**	191	6.1%
		5,277		5,563	
Foreign exchange differential recoverable through the tollmaking process		**(330)**		(337)	
		4,947		5,226	
Other					
Medium-Term Notes					
Canadian dollars	2005 to 2030	**342**	**6.6%**	342	6.6%
U.S. dollars (2002 and 2001 – US$665)	2006 to 2029	**1,050**	**6.8%**	1,059	6.8%
Subordinated Debentures					
U.S. dollars (2002 and 2001 – US$57)	2006	**90**	**9.1%**	91	9.1%
Unsecured Loans and Debentures					
Canadian dollars	2003	**110**	**8.4%**	110	8.4%
U.S. dollars (2002 – US$109; 2001 – US$123)	2006 to 2011	**172**	**8.3%**	195	8.3%
		1,764		1,797	
		9,332		9,830	
Less: Current Portion of Long-Term Debt		**517**		483	
		8,815		9,347	

(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 – 8.3 per cent (2001 – 8.3 per cent); and Other U.S. dollar subordinated debentures – 9.0 per cent (2001 – 8.9 per cent).

Mandatory Retirements Mandatory retirements resulting from maturities and sinking fund obligations of the long-term debt of the Company approximate: 2003 – $517 million; 2004 – $386 million; 2005 – $375 million; 2006 – $453 million; and 2007 – $621 million.

Universal Shelf Programs At December 31, 2002, $2 billion of common shares, preferred shares and/or debt securities including medium-term notes could be issued under TransCanada's universal shelf program in Canada and US$1 billion of common shares, preferred shares and/or debt securities could be issued under TransCanada's universal shelf program in the U.S.

Alberta System

Debentures Debentures amounting to $225 million have retraction provisions which entitle the holders to require redemption of up to 8.0 per cent of the then outstanding principal plus accrued and unpaid interest on repayment dates. No redemptions have been made to December 31, 2002.

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.

Medium-Term Notes Medium-term notes amounting to $98 million have retraction provisions which entitle the holders to require redemption of the principal plus accrued and unpaid interest on repayment dates in 2003.

Other

Medium-Term Notes Medium-term notes amounting to $150 million and US$145 million have retraction provisions which entitle the holders to require redemption of the principal plus accrued and unpaid interest in 2005 and 2004, 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 a rate based on the then U.S. Treasury 30 year bond yield plus a market-based corporate credit spread.

Financial Charges

Year ended December 31	2002	2001	2000
(millions of dollars)			
Interest on long-term debt	**850**	890	974
Regulatory deferrals and amortizations	**(17)**	(30)	(11)
Short-term interest and other financial charges	**34**	38	47
	867	898	1,010
Financial charges – discontinued operations	**–**	(9)	(57)
	867	889	953

The Company made interest payments of $866 million for the year ended December 31, 2002 (2001 – $936 million; 2000 – $1,024 million).

NOTE 9 Non-Recourse Debt of Joint Ventures

	Maturity Dates	2002 Outstanding December 31 (1)	2002 Weighted Average Interest Rate (2)	2001 Outstanding December 31 (1)	2001 Weighted Average Interest Rate (2)
Great Lakes					
Senior Unsecured Notes					
(2002 – US$261; 2001 – US$284)	2005 to 2030	**412**	**8.0%**	452	8.1%
Iroquois					
Senior Unsecured Notes					
(2002 – US$151; 2001 – US$82)	2010 to 2027	**239**	**7.5%**	132	8.7%
Bank Loan					
(2002 – US$16; 2001 – US$71)	2009	**25**	**3.2%**	112	5.7%
Foothills					
Senior Unsecured Notes	2005	**325**	**3.3%**	336	3.1%
Senior Secured Notes	2005	**62**	**6.7%**	63	6.3%
Trans Québec & Maritimes					
First Mortgage Bonds	2005 to 2010	**143**	**7.3%**	143	7.3%
Term Loan	2003	**40**	**2.8%**	42	4.6%
TC PipeLines, LP					
Senior Unsecured Notes					
(2002 – US$4; 2001 – US$7)	2004	**6**	**3.0%**	11	5.3%
Other	2003 to 2012	**45**	**5.6%**	48	6.5%
		1,297		1,339	
Less: Current Portion of Non-Recourse Debt of Joint Ventures		**75**		44	
		1,222		1,295	

(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, 2002, the effective weighted average interest rates on the bank loan of Iroquois and senior unsecured notes of Foothills resulting from swap agreements are 4.8 per cent (2001 – 6.3 per cent) and 5.8 per cent (2001 – 5.9 per cent), respectively.

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 mandatory retirements resulting from maturities and sinking fund obligations of the non-recourse joint venture debt approximates: 2003 – $75 million; 2004 – $42 million; 2005 – $462 million; 2006 – $26 million; and 2007 – $24 million.

Financial Charges of Joint Ventures

Year ended December 31	2002	2001	2000
(millions of dollars)			
Interest on long-term non-recourse debt	**90**	107	149
Other	**–**	–	5
	90	107	154
Financial charges of joint ventures – discontinued operations	**–**	–	(41)
	90	107	113

The Company's proportionate share of the interest payments of joint ventures in continuing operations was $88 million for the year ended December 31, 2002 (2001 – $100 million; 2000 – $99 million).

NOTE 10 Junior Subordinated Debentures and Preferred Securities

December 31	Maturity Dates	2002	2001
		(millions of dollars)	
Junior Subordinated Debentures			
8.75% Issue (2002 and 2001 – US$160 million)	2045	**218**	218
Preferred Securities			
8.25% Issue (2002 – US$13 million; 2001 – US$12 million)	2047	**20**	19
		238	237

The foreign exchange differential on the principal amount of the 8.75 per cent Junior Subordinated Debentures and 8.25 per cent Preferred Securities, which are Canadian Mainline financings, will be recovered through the tollmaking process.

Junior Subordinated Debentures The US$160 million 8.75 per cent Junior Subordinated Debentures are redeemable at par by the Company. The Company may elect to defer interest payments on the Junior Subordinated Debentures. Interest and deferred interest, if any, are payable in cash.

Preferred Securities The US$460 million 8.25 per cent Preferred Securities are redeemable by the Company at par at any time on or after October 8, 2003, and in certain circumstances, prior to that date. The Company 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 Company, the Preferred Securities are classified into their respective debt and equity components. The equity component of the Preferred Securities is $674 million at December 31, 2002 (2001 – $675 million).

On November 7, 2001, the Company redeemed US$200 million of 8.50 per cent Preferred Securities, including accrued and unpaid interest to the redemption date, without premium or penalty.

The Company incurred preferred securities charges, after-tax, of $36 million for the year ended December 31, 2002 (2001 – $45 million; 2000 – $44 million).

NOTE 11 Preferred Shares

December 31	Number of Shares	Dividend Rate Per Share	Redemption Price Per Share	2002	2001
	(thousands)			*(millions of dollars)*	
Cumulative First Preferred Shares					
Series U	4,000	$2.80	$50.00	**195**	195
Series Y	4,000	$2.80	$50.00	**194**	194
				389	389

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

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

NOTE 12 Common Shares

	Number of Shares	Amount
	(thousands)	*(millions of dollars)*
Outstanding at January 1, 2000	474,531	4,535
Exercise of options	382	5
Outstanding at December 31, 2000	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**

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 478.3 million and 480.7 million (2001 – 475.8 million and 477.6 million; 2000 – 474.6 million and 475.2 million), respectively.

Stock Options	Number of Shares	Weighted Average Exercise Prices	Options Exercisable
	(thousands)		*(thousands)*
Outstanding at January 1, 2000	12,871	$ 20.27	9,661
Granted	3,475	$ 10.30	
Exercised	(382)	$ 12.86	
Cancelled or expired	(573)	$ 18.85	
Outstanding at December 31, 2000	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**

The following table summarizes information about stock options outstanding at December 31, 2002.

	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 $13.91	2,243	7.1	$10.62	1,889	$10.72
$14.21 to $18.89	3,098	7.1	$17.52	2,286	$17.35
$19.00 to $20.59	2,830	5.7	$20.07	2,780	$20.09
$21.00 to $21.86	2,173	8.9	$21.43	755	$21.42
$22.85 to $24.61	2,548	5.1	$24.49	2,548	$24.49
	12,892	6.8	$18.92	10,258	$18.95

The 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. Options may be exercised at a price determined at the time the option is awarded. Generally, 25 per cent of the common shares subject to an option may be purchased on the award date and 25 per cent on each of the three following award date anniversaries. On February 25, 2002, the Company issued 1,946,300 options to purchase common shares at $21.43 under the Company's Key Employee Stock Incentive Plan. At December 31, 2002, an additional six million common shares have been reserved for future issuance under KESIP. The Company is recording compensation expense over the three year vesting period.

Restricted Share Unit (RSU) Plan Effective January 1, 2002, the Company implemented the RSU plan. This is a long-term, broad-based employee incentive plan, which granted units to each eligible employee. The units will vest at the end of three years, should certain conditions be achieved 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 will be paid at the end of the vesting period.

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. The Plan was reaffirmed by shareholders in 2001 with certain amendments.

Restriction on Dividends Certain terms of the Company's preferred shares, preferred securities, junior subordinated debentures and debt instruments could restrict the Company's ability to declare dividends on preferred and common shares. At December 31, 2002, such terms did not restrict or alter the Company's ability to declare dividends.

NOTE 13 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 and represent the net unrealized gains or losses on the derivatives, partially offset the foreign exchange adjustment in Shareholders' Equity. 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. 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, 2002, for foreign currency and interest rate derivatives, total credit risk and the largest credit exposure to a single counterparty were $168 million and $60 million, respectively. At December 31, 2002, for power energy trading contracts, total credit risk and the largest credit exposure to a single counterparty were $4 million and $1 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, 2002 and 2001, 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 exposure on an after-tax basis. The cross-currency swaps have a floating interest rate 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 5 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 in Shareholders' Equity.

Asset/(Liability) at December 31	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
(millions of dollars)				
Foreign Exchange Risk				
Cross-currency swaps				
U.S. dollars	**(8)**	**(8)**	(5)	(5)
Forward foreign exchange contracts				
U.S. dollars	**(4)**	**(4)**	(6)	(6)
Interest rate swaps				
Canadian dollars	**1**	**9**	–	–
U.S. dollars	**1**	**(13)**	–	(1)

At December 31, 2002, the principal amounts of cross-currency swaps were US$350 million (2001 – US$150 million), principal amounts of forward foreign exchange contracts were US$225 million (2001 – US$375 million) and principal amounts of interest rate swaps were $309 million (2001 – nil) and US$350 million (2001 – US$50 million).

Reconciliation of Foreign Exchange Adjustment

December 31	2002	2001
(millions of dollars)		
Balance at beginning of year	**13**	13
Translation gains on foreign currency denominated net assets	**3**	11
Foreign exchange losses on derivatives, and other	**(2)**	(11)
	14	13

Energy Price Risk Management The Company executes power and natural gas derivatives for overall management of its contractual portfolio. The Company's portfolio of power and natural gas derivatives is primarily comprised of swap and option contracts for periods of up to 4 years, with fixed and floating price commitments. The fair values of power and natural gas derivatives have been calculated at year-end using estimated forward prices for the relevant period. The fair values of the swap and option contracts as at December 31, 2002 and 2001 are shown in the table below.

Asset/(Liability) at December 31	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
(millions of dollars)				
Swaps – power	**(36)**	**(36)**	–	(1)
Options – gas	**(3)**	**(3)**	–	–

At December 31, 2002, notional volumes were 5,604 gigawatt hours (GWh) (2001 – 6,013 GWh) for power swaps, and 6.3 Bcf (2001 – nil) for gas options.

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

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 and the Canadian Mainline through the use of foreign currency and interest rate derivatives. These derivatives are comprised of contracts for periods up to 10 years. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms.

Asset/(Liability) at December 31	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
(millions of dollars)				
Foreign Exchange Risk				
Cross-currency swaps	**46**	**46**	88	88
Interest Rate Risk				
Interest rate swaps				
Canadian dollars	**4**	**45**	4	26
U.S. dollars	**(1)**	**4**	–	(3)

At December 31, 2002, the principal amounts of cross-currency swaps were US$162 million (2001 – US$407 million). Notional principal amounts for interest rate swaps were $1,024 million (2001 – $780 million) and US$175 million (2001 – US$125 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 carrying amount and fair value of U.S. dollar interest rate swaps at December 31, 2002 were $2 million (2001 – $2 million) and $55 million (2001 – $30 million), respectively. Notional principal amounts were US$250 million (2001 – US$200 million). These derivatives are comprised of contracts for periods up to 8 years.

Other Fair Values

December 31	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
(millions of dollars)				
Long-Term Debt				
Alberta System	**2,892**	**3,420**	3,129	3,611
Canadian Mainline	**5,277**	**6,080**	5,563	6,245
Other	**1,765**	**1,904**	1,797	1,837
Non-Recourse Debt of Joint Ventures	**1,297**	**1,427**	1,339	1,408
Junior Subordinated Debentures	**274**	**276**	274	276

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

NOTE 14 Income Taxes

Provision for Income Taxes

Year ended December 31	2002	2001	2000
(millions of dollars)			
Current			
Canada	**229**	307	246
Foreign	**41**	46	34
	270	353	280
Future			
Canada	**193**	70	41
Foreign	**54**	57	33
	247	127	74
	517	480	354

Geographic Components of Income

Year ended December 31	2002	2001	2000
(millions of dollars)			
Canada	**1,042**	933	858
Foreign	**280**	300	203
Income from continuing operations before income taxes	**1,322**	1,233	1,061

Reconciliation of Income Tax Expense

Year ended December 31	2002	2001	2000
(millions of dollars)			
Income from continuing operations before income taxes	**1,322**	1,233	1,061
Income from regulated operations not subject to tax currently	**(22)**	(130)	(245)
	1,300	1,103	816
Federal and provincial statutory tax rate	**39.2%**	42.1%	44.6%
Expected income tax expense	**510**	464	364
Non-deductible expenses	**1**	3	3
Net difference between the federal and provincial statutory tax rate and rate of foreign authorities	**(13)**	(13)	(8)
Large corporations tax	**30**	31	32
Change in valuation allowance	**8**	–	(8)
Adjustment to future tax assets and liabilities for enacted changes in tax laws and rates	**–**	–	(28)
Other	**(19)**	(5)	(1)
Actual income tax expense	**517**	480	354

Future Income Tax Assets and Liabilities

December 31	2002	2001
(millions of dollars)		
Net operating and capital loss carryforwards	**91**	180
Deferred costs	**49**	91
Deferred revenue	**55**	49
Alternative minimum tax credits	**31**	40
Other	**41**	29
	267	389
Less: Valuation allowance	**33**	25
Future income tax assets, net of valuation allowance	**234**	364
Difference in accounting and tax bases of plant, equipment and power purchase arrangements	**345**	282
Investments in subsidiaries and partnerships	**107**	116
Other	**8**	5
Future income tax liabilities	**460**	403
Net future income tax liabilities	**226**	39

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 $1,702 million at December 31, 2002 (2001 – $1,716 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 $60 million at December 31, 2002 (2001 – $54 million).

Income Tax Payments Income tax payments of $257 million were made during the year ended December 31, 2002 (2001 – $292 million; 2000 – $231 million).

NOTE 15 Notes Payable

	2002		2001	
	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	**258**	**2.9%**	340	2.3%
U.S. dollars	**39**	**1.4%**	–	–
Notes Payable of Joint Ventures				
Canadian dollars	–	–	3	4.7%
	297		343	

Total credit facilities of $2 billion at December 31, 2002, were available to support the Company's commercial paper program and for general corporate purposes. Of this total, $1.5 billion represents a new committed syndicated credit facility established in December 2002 which replaced existing lines set to expire in mid-2003. The new 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 revolving unless during a term out period.

At December 31, 2002, the Company had used approximately $269 million of its total lines of credit for letters of credit to support its ongoing commercial arrangements. If used, 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 $1 million for the year ended December 31, 2002 (2001 – $1 million).

NOTE 16 Employee Future Benefits

The Company sponsors defined benefit pension plans that cover substantially all employees and sponsored a defined contribution pension plan which was effectively terminated at December 31, 2002. The defined benefit pension plans are based on years of service and highest average earnings over three consecutive years of employment. Under the defined contribution pension plan, Company contributions were based on the participating employees' pensionable earnings. As a result of the termination of the defined contribution pension plan, members of this plan were awarded retroactive service credit under the defined benefit plans for all years of service. In exchange for past service credit, members surrendered the accumulated assets in their defined contribution accounts to the defined benefit plan as at December 31, 2002. This plan amendment is subject to regulatory approval and resulted in unamortized past service costs of $44 million.

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 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.

The total expense for the defined contribution plan is $6 million for the year ended December 31, 2002 (2001 – $7 million; 2000 – $8 million).

Information about the Company's defined benefit plans is as follows.

	Pension Benefit Plans		Other Benefit Plans	
	2002	2001	**2002**	2001
(millions of dollars)				
Change in Benefit Obligation				
Benefit obligation – beginning of year	**659**	644	**60**	55
Current service cost	**11**	12	**2**	2
Interest cost	**43**	41	**4**	4
Employee contributions	**1**	1	**–**	–
Benefits paid	**(58)**	(59)	**(4)**	(3)
Actuarial loss	**93**	20	**26**	2
Plan amendment	**92**	–	**7**	–
Benefit obligation – end of year	**841**	659	**95**	60
Change in Plan Assets				
Plan assets at fair value – beginning of year	**573**	612	**–**	–
Actual return on plan assets	**9**	(8)	**–**	–
Employer contributions	**48**	27	**4**	3
Employee contributions	**1**	1	**–**	–
Benefits paid	**(58)**	(59)	**(4)**	(3)
Assets receivable from defined contribution plan	**48**	–	**–**	–
Plan assets at fair value – end of year	**621**	573	**–**	–
Funded status – plan deficit	**(220)**	(86)	**(95)**	(60)
Unamortized net actuarial loss	**246**	123	**33**	7
Unamortized past service costs	**44**	–	**7**	–
Unamortized transitional obligation related to regulated business	**–**	–	**27**	29
Accrued benefit asset/(liability), net of valuation allowance of nil [(1)]	**70**	37	**(28)**	(24)

(1) Assets and liabilities are included in Other Assets and Deferred Amounts, respectively, in TransCanada's consolidated balance sheet.

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

	Pension Benefit Plans			Other Benefit Plans		
	2002	2001	2000	**2002**	2001	2000
Discount rate	**6.25%**	6.75%	6.80%	**6.50%**	6.85%	6.90%
Expected long-term rate of return on plan assets	**7.52%**	7.10%	7.24%	**–**	–	–
Rate of compensation increase	**3.75%**	3.50%	3.50%	**3.75%**	3.50%	3.50%

For measurement purposes, an 8.0 per cent annual rate of increase in the per capita cost of covered health care benefits was assumed for 2003. 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.

	Increase	Decrease
(millions of dollars)		
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	**2002**	2001	2000	**2002**	2001	2000
(millions of dollars)						
Current service cost	**11**	12	15	**2**	2	2
Interest cost	**43**	41	44	**4**	4	3
Expected return on plan assets	**(45)**	(41)	(45)	**–**	–	–
Amortization of transitional obligation related to regulated business	**–**	–	–	**2**	2	2
Amortization of net actuarial loss	**2**	–	–	**–**	–	–
Corporate restructuring giving rise to curtailments	**–**	–	(5)	**–**	–	–
	11	12	9	**8**	8	7
Net benefit plan expense – discontinued operations	**–**	(2)	(2)	**–**	–	–
Net benefit plan expense – continuing operations	**11**	10	7	**8**	8	7

NOTE 17 Changes in Operating Working Capital

Year ended December 31	**2002**	2001	2000
(millions of dollars)			
(Increase)/decrease in accounts receivable	**(45)**	38	(92)
(Increase)/decrease in inventories	**(3)**	52	5
Increase in other current assets	**(53)**	(12)	(6)
Increase/(decrease) in accounts payable	**120**	105	(318)
Increase/(decrease) in accrued interest	**14**	(13)	(5)
	33	170	(416)

NOTE 18 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	Minimum Lease Payments	Amounts Recoverable under Sub-Leases	Net Payments
(millions of dollars)			
2003	27	(9)	18
2004	25	(7)	18
2005	25	(7)	18
2006	24	(7)	17
2007	22	(6)	16

At December 31, 2002, 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). The Redemption Price will be satisfied by TransCanada in cash or, at the election of TransCanada, in common shares of TransCanada or a combination of cash and common shares.

Contingencies The California Attorney General has filed a complaint for civil penalties in California Superior Court under the California Business and Professions Code. The complaint alleges that certain TransCanada subsidiaries and affiliates engaged in sales or purchases of electricity in California for which they failed to comply with the filing requirements of the Federal Power Act and the U.S. Federal Energy Regulatory Commission (FERC) orders. TransCanada believes the actions of its subsidiaries and affiliates were in compliance with the Federal Power Act and FERC requirements. TransCanada considers the complaint to be without merit and is vigorously defending it. The Company has made no provision for any potential liability.

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 their resolution will not have a material impact on the Company's consolidated financial position or results of operations.

Guarantees TransCanada has guaranteed the equity undertaking of a subsidiary which supports the payment of debt obligations of TransGas de Occidente, S.A. (TransGas), in the event a change of law would result in insufficient funds in TransGas to pay the interest and principal on US$206 million of its public debt obligations. 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 19 Discontinued Operations

In July 2001, the Board of Directors approved a plan to dispose of the Company's Gas Marketing business. The Gas Marketing business provided supply, transportation and asset management services, as well as structured financial products and services. In December 1999, the Board of Directors approved a plan (December Plan) to dispose of the Company's International, Canadian Midstream and certain other businesses. The Company's disposals under both plans were substantially completed at December 31, 2001.

The Company remains contingently liable pursuant to obligations under certain energy trading contracts that relate to the divested Gas Marketing business. The contingent liability under these obligations, which could be significant, is contingent on certain future events, the occurrence of which is not determinable, and the amount, if any, is dependent upon future prevailing market prices and conditions. 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. At December 31, 2002, the provision for loss on discontinued operations, including approximately $100 million of deferred after-tax gains and remaining obligations related to the Gas Marketing business, was reviewed and was concluded to be appropriate.

Revenues from discontinued operations for the year ended December 31, 2002, were $36 million (2001 – $12,895 million; 2000 – $15,212 million). The provision for loss on discontinued operations at December 31, 2002 was $234 million (2001 – $264 million). This was comprised of $129 million (2001 – $129 million) relating to Gas Marketing and $105 million (2001 – $135 million) relating to the December Plan.

Net Income/(Loss)

Year ended December 31	2002	2001	2000
(millions of dollars)			
Net Income/(Loss)			
Gas Marketing	–	5	(252)
Income taxes	–	(2)	113
Results of operations prior to plan approval	–	3	(139)
Net Gain/(Loss) from Discontinued Operations			
December Plan [1]	–	34	295
Income taxes	–	(14)	(95)
	–	20	200
Gas Marketing [1]	–	(139)	–
Income taxes	–	49	–
	–	(90)	–
	–	(67)	61

(1) The net loss on disposal in 2001 related to Gas Marketing includes the actual and estimated gains and losses on sale, the results of the discontinued operations between the date of plan approval and the expected dates of disposal, together with direct incremental costs of the dispositions, including severance and transaction expenses. The net gains in 2001 and 2000 related to the December Plan represent adjustments to the 1999 provision resulting from transactions completed and revisions to estimates.

Other Financial Information The following amounts related to discontinued operations are included in the consolidated balance sheet.

December 31	2002	2001
(millions of dollars)		
Current assets	**79**	113
Non-current assets	**109**	212
Current liabilities	**(98)**	(116)
Non-current liabilities	–	(9)
Net Assets of Discontinued Operations	**90**	200

NOTE 20 Significant Differences Between Canadian and U.S. GAAP

Net Income Reconciliation

Year ended December 31	2002	2001	2000
(millions of dollars except per share amounts)			
Net income from continuing operations as reported in accordance with Canadian GAAP	**805**	753	707
U.S. GAAP adjustments			
Preferred securities charges [1]	**(58)**	(77)	(78)
Tax impact of preferred securities charges	**22**	32	34
Unrealized gain/(loss) on derivatives [2]	**30**	(14)	–
Tax impact of gain/(loss) on derivatives	**(12)**	6	–
Unrealized (losses)/gains on energy trading contracts [3]	**(21)**	(17)	37
Tax impact of unrealized (losses)/gains on energy trading contracts	**8**	6	(17)
Income taxes from substantively enacted tax rates [4]	**–**	28	(28)
Gain on early retirement of long-term debt [5]	**–**	–	(15)
Tax impact of gain on early retirement of long-term debt	**–**	–	2
Income from continuing operations in accordance with U.S. GAAP	**774**	717	642
Net (loss)/income from discontinued operations in accordance with U.S. GAAP	**–**	(67)	61
Income before cumulative effect of the application of SFAS No. 133 in accordance with U.S. GAAP	**774**	650	703
Cumulative effect of the application of SFAS No. 133, net of tax [2]	**–**	(2)	–
Extraordinary item:			
Gain on early retirement of long-term debt, net of tax [5]	**–**	–	13
Net income in accordance with U.S. GAAP	**774**	648	716
Net income/(loss) per share in accordance with U.S. GAAP			
Continuing operations	**$ 1.57**	$ 1.46	$ 1.27
Discontinued operations	**–**	(0.14)	0.13
Extraordinary item	**–**	–	0.03
Basic	**$ 1.57**	$ 1.32	$ 1.43
Diluted	**$ 1.56**	$ 1.32	$ 1.43
Net income per share in accordance with Canadian GAAP			
Basic	**$ 1.56**	$ 1.30	$ 1.45
Diluted	**$ 1.55**	$ 1.30	$ 1.45
Dividends per common share	**$ 1.00**	$ 0.90	$ 0.80

(1) Under U.S. GAAP, the financial charges related to preferred securities are recognized as an expense, rather than dividends.

(2) In 2001, the Company adopted the provisions of Statement of Financial Accounting Standards (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 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 2002, net gains of $38 million (2001 – $36 million) from the hedges of changes in the fair value of long-term debt, and net losses of $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. The difference of the change in the fair value of the derivative as compared to the change in the fair value of the hedged item of $18 million (2001 – $(8) million), after tax, is included in earnings for U.S. GAAP purposes. During 2002 and 2001, 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 2002 and 2001 with respect to cash flow hedges. For amounts included in other comprehensive income at December 31, 2002, $(5) million (2001 – $(3) million) relates to the hedge of interest rate risk and $1 million (2001 – $(2) million) relates to the hedge of foreign exchange rate risk. Of these amounts, none are expected to be recorded in earnings during 2003.

At December 31, 2002, additional assets of $198 million (2001 – $162 million) and additional liabilities of $196 million (2001 – $187 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.

(3) Under U.S. GAAP, energy trading contracts are measured at fair value determined as at the balance sheet date. In 2002, 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 is netting all mark-to-market revenues and expenses related to energy trading contracts. This accounting change has been applied retroactively with reclassification of prior periods. In 2003, the Company will fully adopt EITF 02-3. The Company's energy trading contracts that are derivatives held for trading purposes will be measured at fair value and accounted for under the provisions of SFAS No. 133. The Company's energy trading contracts that are not derivatives will not be subject to mark-to-market accounting.

(4) 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.

(5) Under U.S. GAAP, gain on early retirement of long-term debt is recognized as an extraordinary item, rather than ordinary income from operations.

Condensed Statement of Consolidated Income in Accordance with U.S. GAAP (8)

Year ended December 31	2002	2001	2000
(millions of dollars)			
Revenues (3)(8)	**4,284**	4,165	3,921
Cost of sales	**160**	47	52
Other costs and expenses (3)(8)	**1,532**	1,609	1,566
Depreciation	**729**	675	608
	2,421	2,331	2,226
Operating income	**1,863**	1,834	1,695
Other (income)/expenses			
Equity income	**(260)**	(221)	(247)
Other expenses (6)	**850**	931	937
Income taxes	**499**	407	363
	1,089	1,117	1,053
Income from continuing operations in accordance with U.S. GAAP	**774**	717	642
Net (loss)/income from discontinued operations in accordance with U.S. GAAP	**–**	(67)	61
Income before cumulative effect of the application of SFAS No. 133 in accordance with U.S. GAAP	**774**	650	703
Cumulative effect of the application of SFAS No. 133, net of tax (2)	**–**	(2)	–
Extraordinary item:			
Gain on early retirement of long-term debt, net of tax (5)	**–**	–	13
Net income in accordance with U.S. GAAP	**774**	648	716

Comprehensive Income in Accordance with U.S. GAAP

Year ended December 31	**2002**	2001	2000
(millions of dollars)			
Net income in accordance with U.S. GAAP	**774**	648	716
Adjustments affecting comprehensive income under U.S. GAAP			
Foreign currency translation adjustment	**1**	–	(5)
Additional minimum liability for employee future benefits (SFAS No. 87) (7)	**(62)**	(86)	–
Tax impact of additional minimum liability for employee future benefits	**22**	30	–
Unrealized loss on derivatives (2)	**(3)**	(7)	–
Tax impact of loss on derivatives	**(1)**	2	–
Comprehensive income before cumulative effect of the application of SFAS No. 133 in accordance with U.S. GAAP	**731**	587	711
Cumulative effect of the application of SFAS No. 133, net of tax (2)	**–**	(4)	–
Comprehensive income in accordance with U.S. GAAP	**731**	583	711

Condensed Balance Sheet in Accordance with U.S. GAAP (8)

December 31	**2002**	2001
(millions of dollars)		
Current assets	**1,074**	1,162
Long-term energy trading assets (3)	**218**	255
Long-term investments	**1,629**	1,570
Plant, property and equipment	**14,992**	15,379
Regulatory asset (9)	**2,578**	2,613
Other assets	**893**	473
	21,384	21,452
Current liabilities (10)	**1,918**	1,844
Provision for loss on discontinued operations	**234**	264
Long-term energy trading liabilities (3)	**41**	112
Deferred amounts	**593**	503
Long-term debt	**8,963**	9,512
Deferred income taxes (9)	**2,692**	2,556
Preferred securities (11)	**694**	694
Trust originated preferred securities	**218**	218
Shareholders' equity	**6,031**	5,749
	21,384	21,452

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

December 31	Cumulative Translation Account	Minimum Pension Liability (SFAS No. 87)	Cash Flow Hedges (SFAS No. 133)	Total
(millions of dollars)				
Balance at January 1, 2000	18	–	–	18
Foreign currency translation adjustment	(5)	–	–	(5)
Balance at December 31, 2000	13	–	–	13
Additional minimum liability for employee future benefits, net of tax (7)	–	(56)	–	(56)
Unrealized loss on derivatives, net of tax (2)	–	–	(5)	(5)
Cumulative effect of adoption of SFAS No. 133, net of tax (2)	–	–	(4)	(4)
Balance at December 31, 2001	13	(56)	(9)	(52)
Additional minimum liability for employee future benefits, net of tax (7)	**–**	**(40)**	**–**	**(40)**
Unrealized loss on derivatives, net of tax (2)	**–**	**–**	**(4)**	**(4)**
Foreign currency translation adjustment	**1**	**–**	**–**	**1**
Balance at December 31, 2002	**14**	**(96)**	**(13)**	**(95)**

(6) Other expenses included an allowance for funds used during construction of $4 million for the year ended December 31, 2002 (2001 – $5 million; 2000 – $8 million).

(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.

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

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

(10) Current liabilities at December 31, 2002 included dividends payable of $125 million (2001 – $114 million) and current taxes payable of $150 million (2001 – $149 million).

(11) Under U.S. GAAP, the preferred securities are classified as a liability. The fair value of the preferred securities at December 31, 2002 was $743 million (2001 – $740 million). The Company made preferred securities charges payments of $58 million for the year ended December 31, 2002 (2001 – $77 million; 2000 – $78 million).

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

December 31	**2002**	2001
(millions of dollars)		
Deferred Tax Liabilities		
Difference in accounting and tax bases of plant, equipment and power purchase arrangements	**1,703**	1,722
Taxes on future revenue requirement	**876**	897
Investments in subsidiaries and partnerships	**379**	318
Other	**22**	16
	2,980	2,953
Deferred Tax Assets		
Net operating and capital loss carryforwards	**91**	180
Deferred amounts	**104**	140
Other	**126**	102
	321	422
Less: Valuation allowance	**33**	25
	288	397
Net deferred tax liabilities	**2,692**	2,556

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 has expensed stock options granted in 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 $770 million in 2002 (2001 – $643 million; 2000 – $712 million) and net income per share (basic) of $1.56 in 2002 (2001 – $1.30 per share; 2000 – $1.43 per share).

Other In June 2001, the FASB issued 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 Company is required and plans to adopt the provisions of SFAS No. 143 for the quarter ending March 31, 2003. The initial adoption of the new standard is not expected to have a significant impact on the Company's financial statements.

In August 2001, the FASB issued SFAS No. 144 "Accounting for the Impairment or Disposal of Long-term Assets", which addresses the financial accounting and reporting for the impairment or disposal of long-lived assets. Assets to be disposed of through abandonment or an exchange for similar productive assets will be classified as held for use until they cease to be used. SFAS No. 144 establishes criteria that must be met in order to classify an asset or group of assets as held for sale. Assets classified as held for sale will be measured at the lower of their carrying amount or fair value less cost to sell, and depreciation will cease when the asset or group is classified as held for sale. The standard broadens the definition of disposals to be presented as discontinued operations to include components of an entity that comprise operating income and cash flows that clearly can be distinguished, operationally and for financial reporting purposes from the rest of the entity. Adopting the provisions of SFAS No. 144 on a prospective basis did not result in the restatement of income for prior periods.

In November 2002, the FASB issued Financial Interpretation (FIN) 45 that will 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 guarantees that existed as at December 31, 2002, FIN 45 requires additional disclosures which have been included in these consolidated financial statements to the extent applicable to the Company.

In January 2003, the FASB issued FIN 46 that will require 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. The Company does not have any variable interest entities as interpreted under FIN 46 that would result in the consolidation of any additional entities that existed at December 31, 2002.

Summarized Financial Information of Long-Term Investments

Year ended December 31	2002	2001	2000
(millions of dollars)			
Income			
Revenues	**798**	695	700
Other costs and expenses	**(273)**	(191)	(175)
Depreciation	**(146)**	(143)	(156)
Financial charges and other	**(112)**	(136)	(154)
Proportionate share of income before income taxes of long-term investments	**267**	225	215

December 31	2002	2001
(millions of dollars)		
Balance Sheet		
Current assets	**246**	223
Plant, property and equipment	**3,197**	3,171
Other assets and deferred amounts (net)	**112**	139
Current liabilities	**(216)**	(231)
Non-recourse debt	**(1,646)**	(1,669)
Deferred income taxes	**(64)**	(63)
Proportionate share of net assets of long-term investments	**1,629**	1,570

NOTE 21 Subsequent Event

In February 2003, the Company completed the acquisitions of a 31.6 per cent interest in Bruce Power L.P. and an approximate 33.3 per cent interest in Bruce Power Inc., the general partner of Bruce Power L.P., for $376 million, subject to closing adjustments. TransCanada has also funded a one-third share ($75 million) of a $225 million accelerated deferred rent payment to Ontario Power Generation (OPG).

TransCanada acquired the interests as part of a consortium (the Consortium) that includes 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. (British Energy) which owns a 79.8 per cent interest in Bruce Power L.P. as well as a 50 per cent interest in the nine megawatt (MW) Huron Wind L.P. power facility. Bruce Power L.P. is the tenant under a lease with OPG on the Bruce nuclear power facility. The lease expires in 2018 with an option to extend the lease by up to 25 years. Spent fuel and decomissioning liabilities remain the responsibility of OPG.

The Bruce Power facility is made up of two nuclear plants – Bruce B and Bruce A. Bruce B consists of four reactors, currently generating a total of 3,140 MW. Bruce A consists of four 769 MW reactors, which are currently not operating. Two of the Bruce A units (3 and 4) are expected to be restarted and on-line by mid-2003, subject to receipt of all necessary regulatory approvals.

Upon the acquisition of Bruce Power L.P., the Consortium members guaranteed on a several, pro-rata basis certain contingent financial obligations of Bruce Power L.P. related to operator licences, the lease agreement, power sales agreements and contractor services. TransCanada's share of the net exposure under these guarantees at the time of closing was estimated to be approximately $260 million.

TransCanada recorded this acquisition as an equity investment and will report the income as equity income.

SUPPLEMENTARY INFORMATION
SELECTED QUARTERLY AND ANNUAL CONSOLIDATED FINANCIAL DATA

The following sets forth selected quarterly and annual financial data for 2002 and 2001 in millions of dollars except for per share amounts.

	First	Second	Third	Fourth	Annual
(unaudited)					
2002					
Operating Results					
Revenues	**1,246**	**1,345**	**1,285**	**1,338**	**5,214**
Net income from continuing operations	**201**	**220**	**189**	**195**	**805**
Net income applicable to common shares					
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**
2001					
Operating Results					
Revenues	1,365	1,338	1,293	1,279	5,275
Net income from continuing operations	194	202	176	181	753
Net income/(loss) applicable to common shares					
Continuing operations	177	184	159	166	686
Discontinued operations	(8)	(79)	–	20	(67)
	169	105	159	186	619
Share Statistics					
Net income/(loss) per share – Basic and Diluted					
Continuing operations	0.37	0.39	0.33	0.35	1.44
Discontinued operations	(0.02)	(0.17)	–	0.05	(0.14)
	0.35	0.22	0.33	0.40	1.30
Dividend declared per common share	0.225	0.225	0.225	0.225	0.90

QUARTERLY AND ANNUAL SHARE TRADING INFORMATION

(Stock trading symbol TRP)

Toronto Stock Exchange	First	Second	Third	Fourth	Annual
(dollars)					
2002					
High	**22.80**	**23.91**	**23.63**	**23.47**	**23.91**
Low	**19.05**	**21.50**	**20.51**	**22.03**	**19.05**
Close	**21.60**	**23.00**	**22.60**	**22.92**	**22.92**
Volume *(thousands of shares)*	**68,790**	**59,958**	**74,608**	**77,165**	**280,521**
2001					
High	19.52	19.35	21.13	20.95	21.13
Low	14.85	17.50	18.45	18.71	14.85
Close	19.24	18.75	20.34	19.87	19.87
Volume *(thousands of shares)*	94,732	58,892	57,424	77,207	288,255

New York Stock Exchange	First	Second	Third	Fourth	Annual
(U.S. dollars)					
2002					
High	**14.39**	**15.56**	**15.53**	**15.08**	**15.56**
Low	**11.89**	**13.49**	**12.91**	**13.90**	**11.89**
Close	**13.60**	**15.32**	**14.21**	**14.51**	**14.51**
Volume *(thousands of shares)*	**3,569**	**3,083**	**4,959**	**6,929**	**18,540**
2001					
High	12.48	12.68	13.41	13.40	13.41
Low	9.88	11.32	12.17	11.91	9.88
Close	12.23	12.33	12.84	12.51	12.51
Volume *(thousands of shares)*	6,587	4,956	4,936	4,668	21,147

THREE-YEAR FINANCIAL HIGHLIGHTS

	2002	2001	2000
(millions of dollars except where indicated)			
Income Statement			
Revenues	**5,214**	5,275	4,384
Net income from continuing operations	**805**	753	707
Net income	**805**	686	768
Results by segment			
Transmission	**653**	585	623
Power	**146**	168	85
Corporate	**(52)**	(67)	(80)
Continuing operations	**747**	686	628
Discontinued operations	**–**	(67)	61
Net income applicable to common shares	**747**	619	689
Cash Flow Statement			
Funds generated from continuing operations	**1,827**	1,624	1,495
Capital expenditures and acquisitions			
Continuing operations	**814**	1,025	773
Discontinued operations	**13**	52	362
Dividends and preferred securities charges	**546**	517	536
Balance Sheet			
Assets			
Plant, property and equipment			
Transmission	**16,098**	16,509	16,894
Power	**1,334**	1,110	771
Corporate	**64**	66	111
Total assets			
Continuing operations	**19,728**	19,629	19,761
Discontinued operations	**188**	325	5,056
Capitalization			
Long-term debt	**8,815**	9,347	9,928
Non-recourse debt of joint ventures	**1,222**	1,295	1,296
Junior subordinated debentures	**238**	237	243
Preferred securities	**674**	675	969
Preferred shares	**389**	389	389
Common shareholders' equity	**5,747**	5,426	5,211
U.S. GAAP Information			
Net income/(loss)			
Continuing operations before extraordinary items	**774**	715	642
Discontinued operations	**–**	(67)	61
Extraordinary item	**–**	–	13
Net income	**774**	648	716
Net income/(loss) per share			
Continuing operations before extraordinary items	**$ 1.57**	$ 1.46	$ 1.27
Discontinued operations	**$ –**	$ (0.14)	$ 0.13
Extraordinary item	**$ –**	$ –	$ 0.03
Net income applicable to common shares – Basic	**$ 1.57**	$ 1.32	$ 1.43
Net income applicable to common shares – Diluted	**$ 1.56**	$ 1.32	$ 1.43
Common shareholders' equity	**5,642**	5,360	5,163

	2002	2001	2000
Per Common Share Data			
Net income – Basic			
Continuing operations	**$ 1.56**	$ 1.44	$ 1.32
Discontinued operations	**–**	(0.14)	0.13
	$ 1.56	$ 1.30	$ 1.45
Net income – Diluted	**$ 1.55**	$ 1.30	$ 1.45
Dividends declared	**$ 1.00**	$ 0.90	$ 0.80
Book Value[1]	**$ 11.99**	$ 11.38	$ 10.97
Market Price			
Toronto Stock Exchange *(Cdn dollars)*			
High	**23.91**	21.13	17.25
Low	**19.05**	14.85	9.80
Close	**22.92**	19.87	17.20
Volume *(millions of shares)*	**280.5**	288.2	400.7
New York Stock Exchange *(U.S. dollars)*			
High	**15.56**	13.41	11.50
Low	**11.89**	9.88	6.75
Close	**14.51**	12.51	11.50
Volume *(millions of shares)*	**18.5**	21.1	28.1
Shares outstanding *(millions)*			
Average for the year	**478.3**	475.8	474.6
End of year	**479.5**	476.6	474.9
Registered common shareholders[1]	**34,902**	36,350	30,758
Financial Ratios			
Return on average common shareholders' equity	**13.4%**	11.6%	13.6%
Dividend yield[1]	**4.4%**	4.5%	4.7%
Price/earnings multiple[1]	**14.7**	15.3	11.9
Price/book multiple[1]	**1.9**	1.7	1.6
Debt to debt plus shareholders' equity[2]	**58%**	61%	62%
Cash flow from continuing operations to total debt[2]	**0.19**	0.18	0.10
Earnings to fixed charges[3]	**2.4**	2.2	2.0
Earnings to fixed charges *(per U.S. GAAP)**	**2.2**	2.0	2.0

(1) As at December 31.

(2) Debt does not include non-recourse debt of joint ventures.

(3) The ratio of earnings to fixed charges is determined by dividing the financial charges incurred by the company (including capitalized interest) into its income from continuing operations before financial charges and income taxes, excluding undistributed income from equity investees.

* The ratio is determined in the manner described in (3) above, but utilizing similar information determined in accordance with U.S. GAAP. Differences are described in Note 20 "Significant Differences Between Canadian and U.S. GAAP", to the Consolidated Financial Statements.

INVESTOR INFORMATION

Stock Exchanges, Securities and Symbols Common shares are listed on the Toronto and New York stock exchanges under the symbol: TRP

Preferred shares are listed on the Toronto Stock Exchange under the following symbols:

- Cumulative redeemable first preferred Series U: TRP.PR.X and Series Y: TRP.PR.Y

Preferred securities are listed on the New York Stock Exchange under the following symbols:

- 8.75% Trust Originated Preferred Securities(SM)* (TOPrS(SM)): TCL.Pr
- 8.25% Preferred Securities: TRP.Pr

7.875% NOVA Gas Transmission Ltd. (NGTL) Debentures are listed on the New York Stock Exchange under the symbol: NVA 23

16.50% First Mortgage Pipe Line Bonds due 2007 are listed on the London Stock Exchange.

Dividend Reinvestment and Share Purchase Plan TransCanada's dividend reinvestment and share purchase plan allows shareholders to purchase additional common shares by reinvesting their cash dividend without incurring brokerage or administrative fees. Participants in the plan may also buy additional shares of up to $10,000 (US$7,000) per quarter. Please contact our plan agent, Computershare Trust Company of Canada, for more information on the plan or visit us at www.transcanada.com.

Non-Resident Investors Dividends paid by TransCanada to shareholders outside Canada are subject to Canadian non-resident withholding tax. The general rate is 15 per cent for investors resident in the United States and other countries where Canadian tax treaties apply. Effective January 1, 2001, the U.S. Internal Revenue Service (IRS) requires certain foreign payers of dividends or interest to U.S. persons (including resident aliens) to withhold and pay to the IRS 31 per cent of such payments ("Backup Withholding"). This Backup Withholding is in addition to the non-resident tax rate of 15 per cent required under Canadian law. Residents of non-treaty countries are subject under Canadian law to a 25 per cent withholding tax on dividends.

ANNUAL MEETING

The annual meeting of shareholders is scheduled for April 25, 2003 at 10:30 a.m. (Mountain Daylight Time) at the Roundup Centre, Calgary, Alberta.

DIVIDEND PAYMENT DATES

Scheduled common share dividend payment dates in 2003 are January 31, April 30, July 31 and October 31.

TRANSFER AGENTS, REGISTRARS AND TRUSTEE

Common Shares Computershare Trust Company of Canada (Montréal, Toronto, Winnipeg, Calgary and Vancouver) and Computershare Trust Company (New York)

Preferred Shares Computershare Trust Company of Canada (Montréal, Toronto, Winnipeg, Calgary and Vancouver)

Preferred Securities The Bank of New York (New York)

First Mortgage Pipe Line Bonds CIBC Mellon Trust Company, as agent for National Trust Company (Toronto). Co-Registrar and Paying Agent U.K. Series, 16.50%: Computershare Services plc (London, England)

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* service mark of Merrill Lynch & Co., Inc.

TransCanada Debentures

Canadian Series CIBC Mellon Trust Company (Halifax, Montréal, Toronto, Winnipeg, Regina, Calgary and Vancouver)

8.40% series A	10.50% series O	10.625% series Q	11.90% series S	9.80% series V
11.10% series N	10.50% series P	11.85% series R	11.80% series U	9.45% series W

U.S. Series The Bank of New York (New York) 9.875%, 8.625% and 8.50%

NGTL Debentures

Canadian Series CIBC Mellon Trust Company (Halifax, Montréal, Toronto, Winnipeg, Regina, Calgary and Vancouver)

11.95% series 13	11.20% series 18	12.20% series 20	8.30% series 22
11.70% series 15	12.625% series 19	12.20% series 21	8.90% series 23

U.S. Debentures U.S. Bank Trust National Association (New York) Series 8.50% and 7.875%

U.S. Notes U.S. Bank Trust National Association (New York) Series 8.50%

Subordinated Debentures The Bank of Nova Scotia Trust Company of New York (New York) U.S. Series 9.125%

TransCanada Canadian Medium Term Notes and NGTL Canadian Medium Term Notes CIBC Mellon Trust Company (Halifax, Montréal, Toronto, Winnipeg, Regina, Calgary and Vancouver)

TransCanada U.S. Medium Term Notes The Bank of New York (New York)

NGTL U.S. Medium Term Notes U.S. Bank Trust National Association (New York)

REGULATORY FILINGS

Annual Information Form TransCanada's 2002 Annual Information Form, as filed with Canadian securities commissions and as filed under Form 40-F with the U.S. Securities and Exchange Commission, is available on our Web site at www.transcanada.com. A printed copy may be obtained from:

Corporate Secretary TransCanada PipeLines Limited, P.O. Box 1000, Station M, Calgary, Alberta, Canada T2P 4K5

SHAREHOLDER ASSISTANCE

If you are a registered shareholder and have questions regarding your account, please contact our transfer agent in writing, by phone, fax or e-mail at:

Computershare Trust Company of Canada 100 University Avenue, 9th floor, Toronto, Ontario, Canada M5J 2Y1

Toll-free: 1-888-267-6555 Fax: 1-888-453-0330 (North America)

Telephone: 1-514-982-7270 Fax: 1-416-263-9394 (outside North America)

E-mail: caregistryinfo@computershare.com

VISIT OUR WEB SITE

To access TransCanada's corporate and financial information, including quarterly reports, news releases, real-time conference call Web casts and investor presentations, visit us at www.transcanada.com/investor

BENEFICIAL SHAREHOLDERS

If you hold your shares in a brokerage account, questions should be directed to your broker on all administrative matters. To receive quarterly reports, please contact Computershare or visit our Web site.

BOARD OF DIRECTORS

Richard F. Haskayne,
O.C., F.C.A.*
Chairman
TransCanada
PipeLines Limited
Calgary, Alberta

Harold N. Kvisle
President and CEO
TransCanada
PipeLines Limited
Calgary, Alberta

Douglas D. Baldwin (2)(3)
Corporate Director
Calgary, Alberta

Ronald B. Coleman (1)(3)
President
R. B. Coleman
Consulting Co. Ltd.
Calgary, Alberta

Wendy Dobson (2)(4)
Professor, Rotman School
of Management and
Director, Institute for
International Business,
University of Toronto
Uxbridge, Ontario

The Hon. Paule Gauthier,
P.C., O.C., O.Q., Q.C. (1)(3)
Senior Partner
Desjardins Ducharme
Stein Monast
Québec, Québec

Kerry L. Hawkins (1)(4)
President
Cargill Limited
Winnipeg, Manitoba

S. Barry Jackson **(1)(3)
Chairman
Resolute Energy Inc.
Deer Creek Energy Limited
Calgary, Alberta

David P. O'Brien (2)(4)
Chairman
EnCana Corporation
Calgary, Alberta

James R. Paul (1)(2)
Chairman
James and Associates
Kingwood, Texas

Harry G. Schaefer,
F.C.A. (1)(2)
President
Schaefer & Associates Ltd.
and Vice-Chairman
TransCanada
PipeLines Limited
Calgary, Alberta

W. Thomas Stephens (3)(4)
Corporate Director
Greenwood Village,
Colorado

Joseph D. Thompson,
P. Eng. (3)(4)
Chairman
PCL Construction Group Inc.
Edmonton, Alberta

* Non-voting member of all committees of the Board
** Appointed December 3, 2002

(1) Member, Audit and Risk Management Committee
(2) Member, Governance Committee
(3) Member, Health, Safety and Environment Committee
(4) Member, Human Resources Committee

Si vous désirez vous procurer un exemplaire de ce rapport en français, veuillez consulter notre site Web ou vous adresser par écrit à TransCanada PipeLines Limited, bureau du secrétaire.

CORPORATE GOVERNANCE

Please refer to TransCanada's Notice of 2003 Annual and Special Meeting of Shareholders and Management Proxy Circular for the company's report on Corporate Governance.

ETHICS HELP-LINE

The audit committee of the Board of Directors has established an anonymous and confidential toll free telephone number for employees, contractors and others to call with respect to accounting irregularities and ethical violations. The Ethics Help-Line number is 1 (888) 920-2042.

ELECTRONIC PROXY VOTING AND DELIVERY OF DOCUMENTS

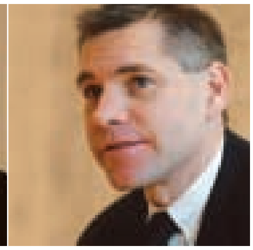
In 2002 we introduced electronic proxy solicitation and voting and electronic delivery of documents (annual report, management proxy circular, notice of meeting and view-only proxy form) for registered and beneficial shareholders. We will be doing the same in 2003.

This will provide increased convenience to shareholders, benefits to the environment and reduced mailing and printing costs for the corporation. We will continue to provide printed copies of these documents for those shareholders preferring this format.

EXECUTIVE OFFICERS

Harold N. Kvisle
President and
Chief Executive Officer

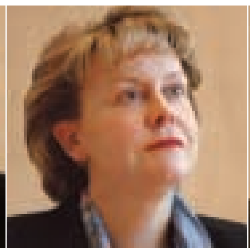
Albrecht W.A. Bellstedt, Q.C.
Executive Vice-President,
Law and General Counsel



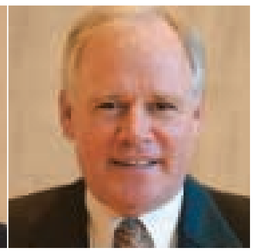
Russell K. Girling
Executive Vice-President
and Chief Financial Officer

Dennis J. McConaghy
Executive Vice-President,
Gas Development

Alexander J. Pourbaix
Executive Vice-President,
Power Development



Sarah E. Raiss
Executive Vice-President,
Corporate Services



Ronald J. Turner
Executive Vice-President,
Operations and Engineering

TRANSCANADA IN THE COMMUNITY

Copies of the Annual Report on Environment, Health and Safety, and Community and the Submission to the Climate Change Voluntary Challenge and Registry are available at www.transcanada.com. If you would like to receive a copy of these reports by mail, please contact:

Communications and Government Relations P.O. Box 1000, Station M, Calgary, Alberta T2P 4K5
(403) 920-2000

METRIC CONVERSION TABLE

Metric	Imperial	Factor
Kilometres	miles	0.62
Millimetres	inches	0.04
Gigajoules	million British thermal units	0.95
cubic metres*	cubic feet	35.3
degrees Celsius	degrees Fahrenheit	Multiply by 1.8, then add 32 degrees. To convert to Celsius, subtract 32 degrees, then divide by 1.8

* The conversion is based on natural gas at a base pressure of 101.325 kilopascals and a base temperature of 15 degrees Celsius.

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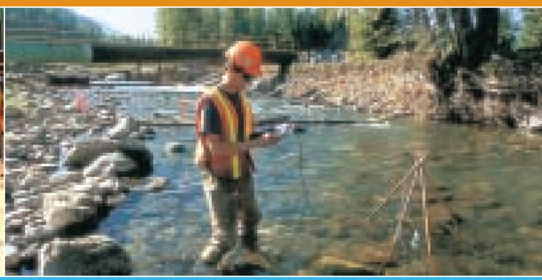
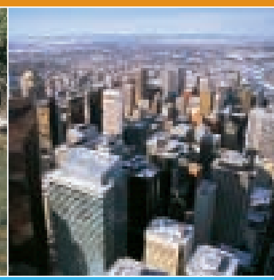
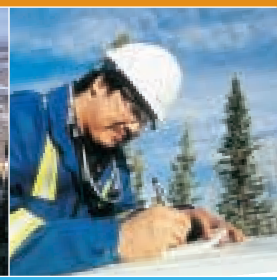

TRANSCANADA PIPELINES LIMITED
TransCanada Tower 450 – First Street SW Calgary Alberta T2P 5H1 **(403) 920-2000**

TransCanada welcomes questions from shareholders and investors. Please contact:
David Moneta, Director, Investor Relations at **1 (800) 361-6522** (Canada and U.S. Mainland)

Visit TransCanada's Web site at **www.transcanada.com**

TransCanada
In business to deliver ™