2000 ANNUAL REPORT

objective: **restore and strengthen our financial position.**

Better faster cheaper

result: **a better bottom line.**

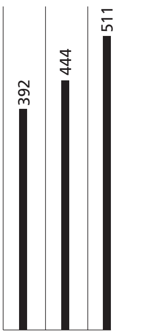
TransCanada

In business to deliver ™

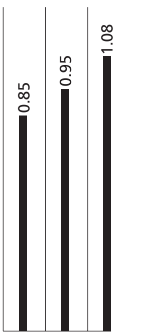
this is
our bottom line

Our year-end 2000 financial results reflect the achievement of our principal objective: to restore and strengthen TransCanada's financial position.

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



Net Income Per Share from Continuing Operations
(dollars)



Financial Highlights

OPERATING RESULTS

December 31 *(millions of dollars)*	**2000**	1999	1998
Income Statement			
Net income applicable to common shares from continuing operations	**511**	444	392
Net income/(loss) applicable to common shares	**711**	(80)	361
Cash Flow			
Funds generated from continuing operations	**1,226**	1,033	1,100
Capital expenditures from continuing operations	**518**	1,323	2,445
Balance Sheet			
Long-term debt	**9,928**	11,591	11,333
Common shareholders' equity	**5,162**	4,897	5,277

COMMON SHARE STATISTICS

Year ended December 31	**2000**	1999	1998
Net income per share from continuing operations	**$ 1.08**	$ 0.95	$ 0.85
Net income/(loss) per share from discontinued operations	**$ 0.42**	$ (1.12)	$ (0.07)
Net income/(loss) per share	**$ 1.50**	$ (0.17)	$ 0.78
Funds generated per share from continuing operations	**$ 2.58**	$ 2.20	$ 2.39
Common shares outstanding *(millions)*			
Average for the period	**474.6**	469.5	460.0
End of period	**474.9**	474.5	463.7

CHAIRMAN'S MESSAGE to SHAREHOLDERS

Last year, the Chairman's message covered the tough choices and necessary actions taken by the Board of Directors in four key areas for which the Board has ultimate responsibility: management, strategy, finances and dividend policy. The Board is pleased to report that those difficult actions resulted in TransCanada delivering on its commitment to restore the integrity of its balance sheet by reducing debt and improving earnings. Most importantly, TransCanada re-emerged as a leader in the North American energy industry. In 2000, TransCanada did what it said it would do.

TransCanada's actions in 2000 included re-deploying the proceeds from the sale of the international and midstream businesses to repay debt, as well as capturing growth opportunities in its core businesses. Primarily as a result of able execution by management and employees, aided by high commodity prices, the company expects to surpass estimated proceeds from the sale of non-core assets. As announced in October 2000, we raised our estimate to $3.45 billion. Success in the divestiture program allowed TransCanada to retire a significant amount of term debt and preferred shares in 2000. All of this is expected to lead to lower financial and preferred equity charges in the next year.

TransCanada also made strategic investments in its power business in 2000, including successful bids in Alberta's power auctions, increased ownership in Ocean State Power and TransCanada Power, L.P., and the initial development of two new power plants in Alberta. It is anticipated these initiatives will contribute to an increase in earnings in TransCanada's power business in 2001 and beyond.

The company's efforts in 2000 also resulted in significant improvement in total earnings, which allowed us to increase the dividend in early 2001. Today, TransCanada's share price has shown significant recovery from its level in early 2000. Indeed, shareholders that remained with TransCanada through the difficult times, new investors who saw promise in the company's actions, as well as those who continued to invest in the company in 2000, have been rewarded by these actions.

TransCanada's success over the year was made possible through hard work and dedication of my fellow Directors; the company's President and Chief Executive Officer, Doug Baldwin; the Executive Leadership Team and employees. The Directors appreciate and applaud everyone's efforts.

Later this year, Mr. Baldwin will retire as President and Chief Executive Officer, but remain a director of the company. We thank him for his perseverance and congratulate him for a legacy of leading TransCanada through a difficult period in the company's history. This year will also see the retirement of Harold P. Milavsky from the Board after 13 years of combined service to NOVA Corporation and TransCanada. The Board would like to sincerely thank and acknowledge Mr. Milavsky's outstanding contribution to the affairs of the company, and specifically his extraordinary efforts as Chairman of the Audit and Risk Management Committee.

TransCanada's actions in the areas of management, strategy, finances and dividend policy speak for themselves - we have delivered. TransCanada has the financial capability to pursue a number of options, including growing the gas transmission and power businesses, positive dividend adjustments, further debt retirement and/or repurchasing shares. Looking ahead, now that it has restored and strengthened its balance sheet, TransCanada is positioned to provide solid value for shareholders this year and in the years ahead. TransCanada will continue to deliver.

On behalf of the Board of Directors,

R. F. Haskayne

Richard F. Haskayne
Chairman of the Board of Directors

REPORT TO SHAREHOLDERS:

In 2000, we committed to restoring and strengthening TransCanada's financial position. Our performance has shown we've delivered. Here's our report card for 2000 and our plan for improved results and performance in 2001 and beyond.

Net income applicable to common shares for 2000 was $711 million, or $1.50 per share, compared to a net loss of $80 million, or $0.17 per share, in 1999. Net income applicable to common shares from continuing operations before unusual items for 2000 was $605 million compared to $505 million in 1999. Earnings per share, from continuing operations before unusual items, for 2000 was $1.28 compared to $1.08, a 19 per cent increase over 1999. The Board also raised the quarterly dividend for the company's outstanding common shares 12.5 per cent from $0.20 per share to $0.225 per share for the quarter ending March 31, 2001.

In addition to consolidating and integrating our operations over the last year, we continue to address industry changes, a new competitive environment and shifting market demands and conditions. We have positioned ourselves well for the challenging times ahead in order for TransCanada to be the most profitable, competitive and reliable provider of natural gas transportation, power generation, and power and natural gas marketing and trading across Canada and the northern tier of the United States. That is our mission. We will accomplish it by preserving our strong roots in the Western Canada Sedimentary Basin and enhancing our key customer relationships. And we will accomplish it by being better, faster, cheaper.

Our efforts in 2000 of restoring and strengthening our financial position were directed at three objectives:

- strengthening the balance sheet;
- restoring earnings and establishing a growth platform for future earnings, and
- positioning the company with discretionary cash flow and financial capacity post 2000 to achieve our business objectives.

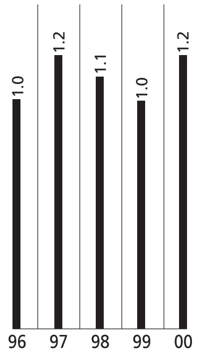
Financial Results

Our year-end 2000 financial results, as highlighted in the accompanying information, illustrate the achievement of these objectives. At the end of 1999, we projected proceeds of $3 billion on the sale of non-core assets. As announced in October 2000, we raised our estimate of anticipated proceeds to $3.45 billion. At December 31, 2000, approximately $2.3 billion of sale proceeds had been realized, and an additional $0.7 billion was received in January 2001, from the sale of our interests in several natural gas transmission assets in Argentina and Chile to TOTALFINAELF. Taken together, this has resulted in a $200 million positive after-tax adjustment to the provision for discontinued operations initially recorded in 1999 and an after-tax gain of $30 million from assets sold out of continuing operations.

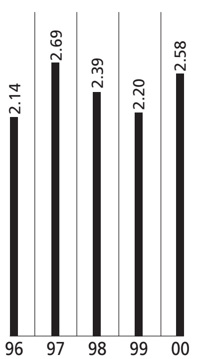
As promised, proceeds from divestitures have been applied primarily to retiring long-term debt and repurchasing preferred shares. We repaid or retired approximately $2.5 billion of term debt and preferred share obligations during 2000. The impact on earnings has been considerable as the repayment of debt has contributed significantly to reducing corporate financing costs. As reported

Certain information contained in this Report to Shareholders has been updated from the information issued via news release January 30, 2001, by TransCanada.

Funds Generated from Continuing Operations
(billions of dollars)



Funds Generated Per Share from Continuing Operations
(dollars)



above, the company recorded strong operating results.

For 2001, TransCanada anticipates discretionary cash flow of approximately $350 million, after accounting for dividends and an anticipated capital expenditure program of $500 million. This, along with enhanced balance sheet strength, provides the company with significant financial capacity. As important as achieving renewed financial strength and stability, we have improved our credibility and reputation as a leading player in the North American energy community. In the future, one measure of our success will be how we effectively utilize our cash to maximize shareholder value. We have a number of options available to us, which involve any or all of the following combinations:

- growth through strategic and disciplined investments;
- increased, sustainable dividend payments;
- further debt retirement, or
- initiation of a share repurchase program.

Ultimately, the decisions that are made will consider the full extent of potential outcomes and impacts. Our bottom line is that any path we take will have to meet the ultimate test of maximizing shareholder value.

When I accepted the position as Chief Executive Officer of TransCanada, it was with the mandate to restore the company financially and position it for growth in a competitive environment. These objectives are well on their way to being achieved. The talented and dedicated people at TransCanada have made that happen. The legacy of these past couple of years will have been the re-emergence of TransCanada as a major participant in the Canadian energy industry. The new Chief Executive Officer will inherit a company poised and ready to master the next challenges in TransCanada's growth and evolution, supported by well-defined strategies and the financial resources to implement them. The search for a new Chief Executive Officer is well under way and, I anticipate, a decision will be made in the near future.

In addition to restoring TransCanada's financial position, our attention has also been directed to our future business, principally pipelines and power generation.

Pipelines:

Considerable work has been done to optimize the return from our pipeline network by developing new products, better access to markets, and competitive and innovative approaches to meeting customers' needs. We have a focused effort on moving toward a regulatory environment with the flexibility to meet changing market and customer needs and to enable TransCanada to better compete in

"When I accepted the position as Chief Executive Officer of TransCanada, it was with the mandate to restore the company financially and position it for growth in a competitive environment. These objectives are well on their way to being achieved."

The Year in Review

11.23
TransCanada Inks Deal to Sell International Assets in Mexico and Venezuela.

10.12
TransCanada Raises Asset Sales Estimate to $3.45 Billion.

10.02
TransCanada Reaches Agreement to Sell Express System.

08.24
TransCanada Acquires Power Generation Capacity.

08.23
TransCanada Reaches Agreement to Sell Netherlands Assets.

08.03
TransCanada Agrees to Sell More Than $1 Billion in Midstream Assets.

the North American market. On January 23, 2001, we announced an agreement in principle with our shippers with respect to tolls on our Alberta System. On February 22, 2001, we announced a settlement for 2001 and 2002 services and pricing on our Canadian Mainline natural gas transmission system that resolves all issues other than cost of capital. The parties agreed that the issue of cost of capital would be determined at the NEB. The settlement is the result of broad industry negotiations and represents a balance of interests among the negotiating parties.

Our decision to divest our non-core assets has seen TransCanada change from being a small player on six continents to sharpening our focus as the major player in the northern tier of North America. We have a strong position in one of the most prolific gas basins in North America and we are poised and positioned to be a participant in the future development of gas reserves in the far north. The decision for northern development rests with the producers, government, aboriginal and local communities. We are pursuing a collaborative approach by working with all participants in order that the best go-forward development plan is implemented. As well, we are examining opportunities to grow TC PipeLines, LP, which remains an important investment vehicle for TransCanada.

Power:
The synergy between our proven businesses of pipelines and power, and the dynamic growth in gas-fired power generation, makes our strategy to build the power side of TransCanada's business both a logical and a win-win proposition. TransCanada has invested $465 million in power operations in the last year and these investments are focused where the company has an existing pipeline and marketing presence. We control or manage 1,612 megawatts of power, up from 932 megawatts last year. Consider that more than 96 per cent of new power plants in the U.S. are natural gas-fired, compared with just 15 per cent of existing facilities. Gas-fired power is growing faster than other forms of generation, such as coal, hydro and nuclear. More than 49,000 megawatts of gas-fired capacity was under construction or approved by the end of 2000 and much of this will be peaking capacity, which has different requirements for financing, risk management, gas supply, related transportation and marketing services.

08.01
TransCanada Sells Interest in Songo Songo Tanzania Project.

07.20
TransCanada Sells Interest in Tuscarora Gas Transmission Company.

06.29
TransCanada to Own 100% of Power Plant in New England.

06.21
TransCanada to Build Two Cogeneration Power Plants.

05.31
TransCanada Agrees to Sell Interests in Several Latin American Assets.

05.04
Company Agrees to Sell Interest in OCENSA.

All these requirements naturally fit with Trans-Canada's existing skill set and operating infrastructure, not to mention the strategic advantage we have through our ability to locate gas-fired power facilities along our gas pipeline routes. Our power group continues to identify and assess potentially attractive markets in the northern tier of North America to take advantage of the tremendous opportunities provided by the current wave of construction of new power generation facilities. As well, TransCanada holds a 41.6 per cent ownership position in, and manages, Canada's largest power L.P. (limited partnership), which has been an excellent growth and power-development vehicle.

We're making all this happen through the implementation of an operationally excellent business model —

better, faster, cheaper.

We know and understand our skill set and talents, and we've identified those we need to continue to succeed. Our expertise is in pipeline and power operations, financial management, natural gas and power marketing and trading, deal structuring and constructing large capital pipeline and power projects. We're improving our abilities and strengths in managing organizational processes to be more effective and efficient in everything we do and to be customer and market focused in identifying what it is we need to do—*we're getting better.*

We enjoy an enviable talent pool of expertise and experience within TransCanada and while we've implemented measures in the last year to reduce the numbers and layers of management that previously existed—starting with our executive team—we're mindful that we need to attract and retain the right mix of talents to deliver on TransCanada's plans. We will continue to develop the leadership abilities of our management teams to operate strategically, proactively and responsively in an increasingly competitive environment—*we're getting faster.*

Best Value for Best Price

We need to improve our ability to provide best value for best price. Cost of service is critical to our customers. We understand that. We're identifying areas where we can become more cost efficient—cheaper—but cheaper where it makes sense in order for us to provide customers with best total cost for the best products and solutions they expect to meet their needs. It's being effective and efficient. *Effective*—doing the right things. *Efficient*—doing things right.

With operational excellence as our guide, our focus in 2001 is toward:

Growth

With restored financial strength, we will focus on profitable growth opportunities in pipelines, power generation, and power and gas marketing and trading. We will make investments in 2001 in defined geographies and business lines that allow us to continue growing earnings in a manner that demonstrates our understanding of risk management and the risk:reward equation. We will continue working to position TransCanada to be a significant player in the development of the Alaska northern slope and Mackenzie Delta gas reserves in order to ensure that northern gas utilizes our existing pipeline system to the markets we serve.

Regulatory Reform

We expect to achieve solid short-term and long-term results. In the short-term, we are working hard to obtain customer support for the regulatory approval of tolls on our Canadian wholly-owned pipelines. In the long-term, we will work with our customers to develop an integrated regulatory model which will deliver acceptable returns for our shareholders and our industry and reflect the changing environment in which we operate.

Operational Excellence

We will continue to improve organizational and operational efficiencies. We have achieved over-all cost savings of $60 million and $95 million in each of the past two years respectively by eliminating costs associated with our existing and divested businesses, optimizing our assets, improving our key processes and simplifying our organization. This annual report is an example of that approach. By producing it in this smaller format, in black and white without coloured inks and photographs, we have reduced costs by $500,000. Further cost efficiencies are being identified for 2001. *We will redouble our efforts to get better, faster, cheaper*.

At TransCanada, we have accomplished much in the past year. We will accomplish more in the year ahead.

Douglas D. Baldwin
President and Chief Executive Officer

MANAGEMENT'S DISCUSSION AND ANALYSIS
CONSOLIDATED FINANCIAL REVIEW

Net income applicable to common shares (net earnings) for 2000 was $711 million or $1.50 per share, compared to a net loss of $80 million or $0.17 per share in 1999. On January 30, 2001, the Board of Directors of TransCanada PipeLines Limited (TransCanada or the company) declared a quarterly dividend of $0.225 per share on the company's outstanding common shares for the quarter ending March 31, 2001, representing a 12.5 per cent increase over the previous quarter.

In late 1999, TransCanada set a strategic direction to capture North American energy growth opportunities by focusing on its core segments of natural gas transmission, power, and natural gas marketing in Canada and the northern tier of the United States. This strategy included a plan to divest all assets not associated with its core businesses in order to strengthen the company's financial position. TransCanada's 2000 financial statements reflect the implementation of this strategy.

In 2000, TransCanada substantially completed its divestiture program and has now sold, or has agreements to sell, assets for proceeds of approximately $3.4 billion. Proceeds received to date have been used primarily to reduce debt and associated financial charges and this is expected to continue as additional proceeds are received in 2001. Businesses remaining to be sold primarily consist of certain of the company's International investments.

Asset sale proceeds in 2000, combined with the company's strong operating cash flow, allowed TransCanada to retire or repurchase approximately $2.5 billion of term debt and preferred shares.

CONSOLIDATED RESULTS-AT-A-GLANCE

Year ended December 31 *(millions of dollars except per share amounts)*	**2000**	1999	1998
Net earnings before unusual items	**605**	505	558
Unusual items	**(94)**	(61)	(166)
Net earnings from continuing operations	**511**	444	392
Net income/(loss) from discontinued operations	**200**	(524)	(31)
Net income/(loss) applicable to common shares	**711**	(80)	361
Net income per share before unusual items	**$ 1.28**	$ 1.08	$ 1.21
Unusual items per share	**(0.20)**	(0.13)	(0.36)
Net income per share from continuing operations	**1.08**	0.95	0.85
Net income/(loss) per share from discontinued operations	**0.42**	(1.12)	(0.07)
Net income/(loss) per share	**$ 1.50**	$ (0.17)	$ 0.78

Net earnings from continuing operations, before unusual items, for the year ended December 31, 2000 were $605 million or $1.28 per share, compared to $505 million or $1.08 per share for 1999 and $558 million or $1.21 per share in 1998.

Solid performance from the Power business in 2000, as well as reduced financial and preferred equity charges as a result of lower net debt balances and preferred share redemptions, are the primary contributors to the increase over 1999 and 1998 results. In addition, tax recoveries of $28 million were recorded in 2000 to reflect the impact of tax law and income tax rate changes. These items were partially offset by losses in the Gas Marketing business.

Also reflected in the results are cost reductions achieved in 2000. TransCanada has substantially exceeded its annualized operating cost savings target of $100 million set at the time of the business combination with NOVA. As a result of the initiatives undertaken across all businesses and in corporate functions, the company achieved annualized cost savings of approximately $95 million ($57 million from continuing operations), before tax, in 1999 and an additional $60 million, before tax, from continuing operations in 2000. A significant portion of the cost savings was delivered by TransCanada's Transmission business and has been shared with its customers.

Effective December 31, 2000, the company retroactively adopted mark-to-market accounting for all of its energy trading contracts (see Note 2, Accounting Changes, in the Notes to Consolidated Financial Statements).

Net earnings for 2000 from continuing operations, after unusual items, were $511 million compared to $444 million and $392 million in 1999 and 1998, respectively.

The unusual items included in the 2000 financial results from continuing operations are a $30 million after-tax gain on asset sales offset by after-tax losses of $124 million recorded in the Gas Marketing segment on certain long-term natural gas contracts. The 2000 results also include a positive $200 million after-tax adjustment to the provision for loss on discontinued operations originally recorded in 1999.

The unusual items included in the 1999 financial results from continuing operations are restructuring and other costs of $108 million, after tax, associated with the strategic direction announced in December 1999, partially offset by a $47 million after-tax gain on the sale of a portion of TransCanada's investment in Northern Border Pipeline Company (Northern Border). The 1998 results from continuing operations reflect restructuring and other costs of $166 million, after tax, related to the business combination with NOVA Corporation (NOVA).

SEGMENT RESULTS-AT-A-GLANCE

Year ended December 31 *(millions of dollars)*	**2000**	1999	1998
Transmission	**612**	671	598
Power	**105**	40	29
Gas Marketing	**(129)**	(5)	24
Corporate	**(77)**	(262)	(259)
Net earnings from continuing operations	**511**	444	392

TRANSMISSION

Net earnings from the Transmission business in 2000 were $612 million. TransCanada's Transmission business is strategically positioned for growth within Canada and the northern tier of the United States. As the industry and business environment change, TransCanada will continue to focus on maximizing the value the company delivers to its customers and shareholders.

Net earnings from this business in 2000 were $612 million, compared to $671 million and $598 million in 1999 and 1998, respectively. Excluding the impact of the sale of TransCanada's investment in Northern Border in 1999 and an after-tax gain of $7 million on the sale of substantially all of TransCanada's investment in Tuscarora Gas Transmission Company (Tuscarora) in 2000, net earnings continue to reflect solid performances in wholly-owned pipelines and North American pipeline ventures (NAPV).

TRANSMISSION RESULTS-AT-A-GLANCE

Year ended December 31 *(millions of dollars)*	**2000**	1999	1998
Wholly-Owned Pipelines			
Alberta System	**219**	219	201
Canadian Mainline	**281**	285	278
BC System	**6**	6	6
	506	510	485
North American Pipeline Ventures			
Great Lakes	**52**	55	53
TC PipeLines, LP	**11**	7	–
Northern Border			
– earnings	**–**	13	37
– gain on sale	**–**	47	–
Iroquois	**13**	12	14
Tuscarora			
– earnings	**2**	3	3
– gain on sale	**7**	–	–
Foothills	**22**	21	21
Trans Québec & Maritimes	**8**	10	7
Other	**(9)**	(7)	(22)
	106	161	113
Net earnings	**612**	671	598

Alberta System

TransCanada's 100 per cent owned natural gas transmission system in Alberta (Alberta System) 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 22,600 kilometre system is one of the largest carriers of natural gas in North America.

A two-year settlement for determination of tolls and services was reached between TransCanada and its shippers on the Alberta System early in 2001. The Alberta System settlement is a significant step toward creating a more competitive natural gas pipeline environment in the Western Canada Sedimentary Basin (WCSB) through the development and implementation of services that will provide TransCanada and its customers operational and contractual flexibility. The new settlement, which establishes a fixed revenue requirement for 2001 and 2002, will provide certainty to shippers and extend the incentive for TransCanada to continue to reduce costs.

Also, in February 2001, the company reached a settlement for 2001 and 2002 services and pricing on the Canadian Mainline that resolves all matters other than cost of capital. The settlement provides the foundation for further discussions to ensure the Canadian Mainline continues to compete effectively for market demand and natural gas supplies.

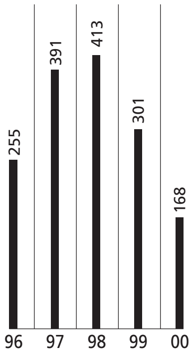
Wholly-Owned Pipelines – Financial Review

ALBERTA SYSTEM

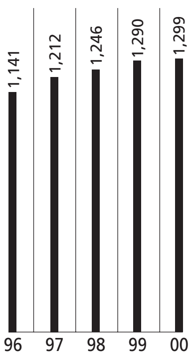
Net earnings of $219 million in 2000 are comparable to 1999 and are $18 million higher than in 1998. Net earnings in 2000 continue to reflect sustained operating and financing cost savings, half of which were retained by TransCanada under the Alberta System's incentive agreement, the Cost-efficiency Incentive Settlement (CEIS) and the Merger Costs and Benefits Agreement (MCBA). The increase in net earnings, when compared to 1998, reflects the growth in average investment base and achievement of cost savings. During the term of the CEIS, the return on a significant portion of the Alberta System investment base was fixed, and therefore was not affected by changes in the approved return on equity.

The Alberta System is one of the largest volume carriers of natural gas in North America and delivered 4,490 billion cubic feet (Bcf) of natural gas in 2000, as compared to 1999 deliveries of 4,535 Bcf. The volumes transported by the Alberta System represent approximately 18 per cent of total North American natural gas production and about 74 per cent of the natural gas produced in the WCSB.

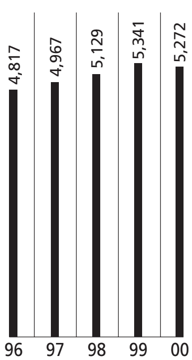
Alberta System Capital Expenditures
(millions of dollars)



Alberta System Revenues
(millions of dollars)



Alberta System Average Investment Base
(millions of dollars)



The Alberta System is regulated by the Alberta Energy and Utilities Board (EUB) under the Gas Utilities Act (Alberta) (GUA). Under the GUA, the rates, tolls and other charges and terms and conditions of service are subject to the approval of the EUB. During the term of the CEIS, the rate of return on deemed common equity relative to new capacity capital was reset annually and was based on the mechanism established in the CEIS.

Incentive Regulation

The CEIS was approved by the EUB in December 1996 and expired at the end of 2000. This incentive-based agreement linked costs to incentives and encouraged cost-efficient pipeline operation and expansion. In 2000, the Alberta System shared operating and financing cost savings of $61 million, before tax, equally with its customers. This compares to before-tax savings of $78 million in 1999 and $37 million in 1998.

For 1999 and 2000, certain operating, maintenance and administrative (OM&A) costs were subject to the MCBA. This agreement was approved by the customers of TransCanada's wholly-owned pipelines in June 1999 and subsequently by the regulators of those pipelines. It provided for a targeted reduction of OM&A costs of $70 million, before tax, by 2001, to be shared between TransCanada and its customers.

Rate Design

On February 4, 2000, the EUB approved TransCanada's new products and receipt-point pricing structure based on distance of haul and pipe diameter. The receipt-point pricing structure, which was implemented in April 2000, replaced the postage-stamp tolling method introduced by the Alberta government in 1980. Postage-stamp tolling dictated the same unit price for natural gas transmission, regardless of how far the gas was transported. In March 1999, TransCanada agreed to contribute $25 million, before tax, per year for two years commencing with implementation toward the transition to the new structure. The receipt-point contracting terms offer natural gas customers in the WCSB a choice of term-variable pricing while providing the same service they previously received.

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 the Québec/Vermont border (Canadian Mainline), and connects with other natural gas pipelines in Canada and the United States.

BC System

TransCanada owns 100 per cent of a 180 kilometre natural gas transmission system extending from Alberta's western border through British Columbia to the U.S. border (BC System), serving markets in the province as well as the Pacific Northwest, California and Nevada.

CANADIAN MAINLINE

The Canadian Mainline generated net earnings of $281 million in 2000, a $4 million decrease compared to 1999 and $3 million higher than 1998. The decrease in net earnings in 2000 compared to 1999, despite an increase in the allowed rate of return on common equity to 9.90 per cent from 9.58 per cent in 1999 and an increase in average investment base of $57 million, is primarily due to cost recoveries relating to capital transactions realized in 1999. These recoveries on capital transactions also contributed to the increased earnings in 1999 over 1998, which were partially offset by a decrease in the allowed rate of return on common equity to 9.58 per cent in 1999 from 10.21 per cent in 1998.

Annual deliveries of natural gas on the Canadian Mainline totalled 2,675 Bcf in 2000, compared to 1999 deliveries of 2,684 Bcf. In 2000, export deliveries comprised approximately 50 per cent of total deliveries, compared to 49 per cent in both 1999 and 1998.

The Canadian Mainline is regulated by the NEB. The NEB sets tolls which allow TransCanada to recover projected costs of transporting natural gas and provide a return on the Canadian Mainline average investment base. New facilities are approved by the NEB before construction begins. Changes in investment base or the return on common equity affect the net earnings of the Canadian Mainline. Most of the operating and financing costs of the Canadian Mainline are fixed and are recovered monthly from customers.

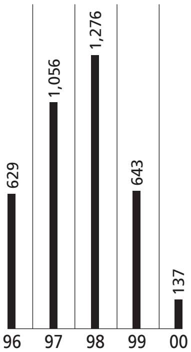
Incentive Regulation

The 2000 Tolls Application was the first tolls application following the expiry of the Incentive Cost Recovery and Revenue Sharing Settlement (the "Incentive Settlement"). It was in substance a cost-of-service application, however, certain mechanisms were used in determining 2000 tolls that are the same or similar to those used under the Incentive Settlement. These include continuation of the Foreign Exchange and Interest Rate Management Programs, and a revenue sharing mechanism for discretionary revenue. Certain OM&A costs were included in the revenue requirement in accordance with the MCBA.

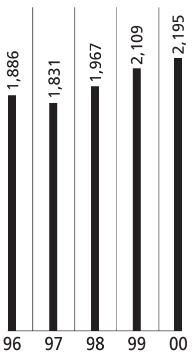
BC SYSTEM

Net earnings of $6 million in 2000 are comparable to both 1999 and 1998. The BC System is regulated by the NEB and tolls are based on a cost-of-service methodology.

Canadian Mainline Capital Expenditures
(millions of dollars)



Canadian Mainline Revenues
(millions of dollars)



Canadian Mainline Average Investment Base
(millions of dollars)

Wholly-Owned Pipelines – Outlook

TransCanada's wholly-owned pipeline business is strategically positioned within the northern tier of North America. The strength of the Transmission business is derived from its operating efficiency and the expertise of its people along with its unique position as the major transporter of Canadian gas both within the WCSB and across the continent.

During 2000, the Transmission business addressed increased competition by focusing on two main areas.

The first area of focus was to maximize the value TransCanada delivers to its customers and its shareholders. The wholly-owned pipeline business accomplished the following in 2000.

- Through a combination of employee reductions and efficiency improvements, annual OM&A costs were further reduced, bringing the total reduction to approximately $70 million or 15 per cent relative to a baseline established as of January 1999. These savings were shared between TransCanada's shippers and its shareholders, in accordance with the MCBA.
- Implementation of streamlined and standardized maintenance processes resulted in reduced capital expenditures of approximately $70 million, or 19 per cent of the 2000 total capital budget.

The second area of focus of the Transmission business was to work with its customers to achieve mutually beneficial services and pricing arrangements for the Alberta System and the Canadian Mainline. On January 23, 2001, TransCanada announced that it had reached a settlement for 2001 and 2002 tolls and services on its Alberta System. This new settlement establishes a fixed revenue requirement for 2001 and 2002 that allows TransCanada to recover projected costs of transporting natural gas and provides a return on the Alberta System average investment base. Under this settlement, cost savings achieved relative to the fixed revenue requirement accrue to TransCanada's shareholders. A memorandum of understanding to be developed from the settlement will require acceptance by TransCanada and the stakeholders. Implementation will require approval by the EUB.

On February 22, 2001, TransCanada announced that it reached a settlement for 2001 and 2002 services and pricing on the Canadian Mainline that resolves all matters other than cost of capital. The settlement establishes OM&A costs for the next two years. All other elements of the 2001 and 2002 revenue requirements will be treated on a flow through basis. This settlement will form the basis of a formal agreement between the parties. Once TransCanada and the stakeholders have completed the agreement, anticipated by early spring 2001, TransCanada will apply to the NEB for approval of the agreement. TransCanada will also request the NEB to determine an appropriate rate of return and capital structure. Until regulatory approvals are obtained for 2001 tolls, interim tolls approved by the NEB are in place.

In 2001, the Transmission business will focus on achieving additional efficiency improvements in all aspects of the business, including further integrating the operation of its wholly-owned pipelines.

EARNINGS

Net earnings for the Alberta System are expected to be lower in 2001 than 2000 primarily due to the expiry of the CEIS, which fixed the rate of return on common equity on a significant portion of the investment base. The recently negotiated settlement, which will replace the CEIS when finalized, is based on a fixed revenue requirement of $1,390 million in 2001 and $1,347 million for 2002, with cost variances flowing to TransCanada's shareholders during the term of the agreement.

For the Canadian Mainline, interim tolls for 2001 are based on an allowed rate of return on common equity of 9.61 per cent in accordance with the NEB adjustment mechanism on a deemed common equity ratio of 30 per cent. Based on the assumptions underlying the interim tolls, net earnings from the Canadian Mainline would decrease in 2001 compared to 2000. This is primarily due to the decrease in rate of return to 9.61 per cent from 9.90 per cent coupled with a decrease in average investment base. In the recent settlement, the parties agreed that the issues of allowed rate of return and capital structure would be determined in a different forum. The resolution of these issues is expected to have an impact on 2001 earnings.

CAPITAL EXPENDITURES

Total capital spending for the wholly-owned pipeline business during 2000 was $309 million. The capital expenditures for 2001, which are expected to be at the same level as 2000, will primarily be for maintenance capital with some modest capital to construct additional receipt and delivery facilities. As a result of excess pipeline capacity out of the WCSB, it is anticipated that capital expenditures will continue at these levels for the next few years. Reduced capital expenditures will result in significant positive cash flow from the wholly-owned pipelines.

Wholly-Owned Pipelines – Business Risks

COMPETITION

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 plants in the province of Alberta and then transporting that gas to other systems for domestic and export deliveries. The Alliance Pipeline, a competitor which began operation in December 2000, has a maximum capacity of 1.5 Bcf per day (Bcf/d) compared to TransCanada's Alberta System average annual pre-Alliance throughput of 12 Bcf/d. The Alberta System has been under threat of by-pass pipelines near the Alberta borders. One of these pipelines has been constructed and another was approved for construction in 2000. The Alberta System's tolling methodology, implemented in April 2000, is intended to enhance TransCanada's capability to provide more competitive pricing and service flexibility and to provide TransCanada with the ability to respond to potential future by-pass pipelines by offering load retention services.

The Canadian Mainline is TransCanada's cross-continent pipeline serving mid-western and eastern markets in both Canada and the United States. The demand for gas in TransCanada's key eastern markets is expected to continue to increase, particularly to meet the growth in gas-fired power generation. TransCanada faces competition for its transportation business to eastern Canadian markets and related export points. The main source of this competition is currently the combination of the newly-constructed Alliance and Vector pipelines described below. In addition, alternatives to year-round transportation on the Canadian Mainline from Alberta to Ontario result from gas being available at all export points during the low demand summer period and, with the completion of Alliance/Vector, from Michigan throughout the year on other pipelines. New customers and existing customers with expiring firm contracts on the Canadian Mainline may use some of these alternatives.

Alliance Pipeline, a 3,000 kilometre 1.5 Bcf/d natural gas pipeline from northeast British Columbia to the Chicago area and Vector, a 550 kilometre 1.0 Bcf/d pipeline from Chicago to Dawn, Ontario, both went into service in late 2000. Alliance is fully subscribed, and Vector substantially subscribed, with 15 year contracts. As a result of these new pipelines and slower than expected production growth from the WCSB, some firm capacity contracts on the Alberta System and the Canadian Mainline have not been renewed upon expiry.

Over the past two years, firm receipt contracts have decreased by 32 per cent on the Alberta System and 27 per cent on the Canadian Mainline compared to the 1998/99 firm contracted capacity on each system. Much of the non-renewed capacity was utilized to provide services of less than a one-year term. For the November 1999 to October 2000 gas year, the Empress plus Saskatchewan receipts into the Canadian Mainline, the McNeill receipts into Foothills/Northern Border systems and the receipts into TransCanada's BC system were 90 per cent, 100 per cent and 89 per cent, respectively, of design capacity. As a result of the reduction in firm contracts and the move to shorter term services, tolls have increased on both the Alberta System and Canadian Mainline consistent with the currently approved rate-making methodology. As additional new gas supply is transported to markets, utilization is expected to increase which would cause the effective tolls to decrease on both systems.

INCENTIVE AGREEMENTS

The CEIS for the Alberta System expired on December 31, 2000. TransCanada has successfully negotiated a new two-year settlement with its customers that will be filed for approval with the EUB in the first quarter of 2001. The settlement provides for a fixed revenue requirement to be recovered through tolls for the years 2001 and 2002 of $1,390 million and $1,347 million, respectively. This fixed revenue requirement may be adjusted up or down during the following year to account for:

- variances in firm service volumes;
- non-firm service revenue;
- variances in pipeline integrity spending;
- foreign exchange losses/gains, and
- changes in federal and provincial income tax rates.

Other major components of the settlement include:

- an increase in the depreciation rate from 3.5 per cent to 4.0 per cent;
- the current menu and level of services are retained or improved, and
- the introduction of new services such as point-to-point Firm Service and one-year non-renewable Firm Receipt Service.

The settlement provides the foundation for resolving several rate design and service issues over the next two years. Resolution of these issues will enhance the competitiveness of both the Alberta System and the WCSB.

During 2000, the Canadian Mainline operated under tolls approved by the NEB based on cost-of-service methodology with OM&A costs subject to the terms of the MCBA. On February 22, 2001, TransCanada announced that it reached a settlement for 2001 and 2002 services and pricing on the Canadian Mainline. This settlement establishes OM&A costs for the two years which provides the company with an incentive to achieve further cost reductions. All other elements of the 2001 and 2002 revenue requirements will be treated on a flow through basis, whereby any variances from estimated amounts will be adjusted in the following year's revenue requirement.

Other major components of the settlement include:

- an increase in the composite depreciation rate from 2.65 per cent in 2000 to 2.75 per cent and 2.90 per cent in 2001 and 2002, respectively;
- continuation of the Foreign Exchange and Interest Rate Management Programs which were part of the previous incentive settlement;
- a commission of up to $5 million to TransCanada to provide an incentive to reduce asset costs and generate incremental revenue, and
- various transportation service enhancements.

In early spring 2001, TransCanada will apply to the NEB for final 2001 tolls on the basis of the settlement. Until final tolls are in place, the NEB has approved interim tolls of $1.13 per gigajoule for Eastern Zone longhaul deliveries, an increase of 12 per cent over 2000.

SAFETY

Public safety continues to be a management priority and TransCanada is proud of its effective collaboration with its customers, communities and regulators. The company emphasizes public awareness programs and its pipeline integrity program continues to be the largest expenditure in the maintenance budget, with planned operating and capital expenditures of $185 million in 2001.

GAS SUPPLY

Based on year-end 1999 estimates, the WCSB had remaining reserves of 64 trillion cubic feet and a reserves-to-production ratio of approximately 11 years at current levels of production. North America is currently experiencing high natural gas prices due to a tight supply/demand balance. TransCanada expects that the high prices will result in continued growth in WCSB supply as producers increase their focus on deeper, more productive areas of the basin. However, it is likely that there will be excess pipeline capacity out of the WCSB for several years.

NORTH AMERICAN PIPELINE VENTURES

Great Lakes

Great Lakes Gas Transmission Company (Great Lakes) connects with the Canadian Mainline at Emerson, Manitoba and serves markets in central Canada and the eastern and midwestern U.S. TransCanada's ownership interest in this 3,387 kilometre pipeline system is 50 per cent.

Northern Border

Northern Border is a 1,956 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 interest in TC PipeLines, LP.

Iroquois

Iroquois Gas Transmission System (Iroquois) connects with the Canadian Mainline and delivers natural gas to customers in the northeastern U.S.

TransCanada's ownership interest in this 604 kilometre pipeline system is 35 per cent.

North American Pipeline Ventures – Financial Review

NAPV is comprised of TransCanada's direct and indirect ownership in various natural gas pipelines and pipeline-related businesses throughout North America as well as project development activities related to TransCanada's pursuit of new gas pipeline opportunities in the Arctic and the rest of North America.

TransCanada's proportionate share of net earnings from NAPV was $106 million in 2000, a decrease of $55 million compared to 1999. Both years include one-time gains on selling certain pipeline investments. Excluding these gains, NAPV's net earnings were $99 million in 2000, a decrease of $15 million compared to $114 million in 1999. This $15 million decrease was primarily due to TransCanada's reduced ownership in Northern Border and increased costs related to TransCanada's northern development activities in 2000.

In 2000, TransCanada realized an after-tax gain of $7 million on the sale of a 49 per cent interest in Tuscarora to TC PipeLines, LP, another NAPV investment. In 1999, TransCanada realized an after-tax gain of $47 million on the sale of its 30 per cent investment in Northern Border to TC PipeLines, LP.

NAPV's 1999 net earnings of $161 million increased by $48 million compared to 1998, primarily due to the gain on sale of Northern Border as the impact of the reduced ownership in Northern Border in 1999 was offset by strong results from other NAPV investments and lower project development costs.

North American Pipeline Ventures – Outlook

TransCanada continues to actively pursue new gas pipeline development and acquisition opportunities in Canada and the northern tier of the United States, where these opportunities are driven by strong customer demand. In addition, TransCanada will continue to pursue value-added opportunities to increase its ownership in its existing NAPV investments.

Tuscarora

Tuscarora operates a 369 kilometre pipeline system transporting gas from Malin, Oregon to Reno, Nevada with delivery points in northeastern California. TransCanada indirectly owns approximately 16.4 per cent of Tuscarora through its interest in TC PipeLines, LP. In addition, TransCanada owns one per cent directly.

Portland

The 471 kilometre Portland Natural Gas Transmission System (Portland) was placed in service in 1999. TransCanada owns 21.4 per cent of Portland, which connects with Trans Québec & Maritimes Pipeline Inc. (TQM) near Pittsburg, New Hampshire and has delivery points in Massachusetts.

Foothills

Foothills Pipe Lines Ltd. (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 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.

NORTHERN DEVELOPMENT

The company continues to pursue northern gas development opportunities. The Alaska gas pipeline project is being developed through Foothills, which the company owns jointly with Westcoast Energy Inc. Foothills holds the regulatory certificate for the Canadian portion of the project and TransCanada, together with Foothills, holds the Alaskan regulatory certificate for the project. This Alaska gas pipeline project, known as ANGTS, has significant advantages over competing proposals to deliver Alaskan gas to the market connection in western Canada. The company is also actively pursuing the Canadian arctic gas opportunity through active participation with stakeholders in the Mackenzie Valley. TransCanada expects both projects to advance to preliminary agreements this year with exact timing driven by the producers and other stakeholders in each basin. These northern projects are opportunities that are expected to create additional growth for the company through new investment as well as add value to TransCanada's existing pipeline assets.

TC PIPELINES, LP

TransCanada owns a 33.4 per cent interest in TC PipeLines, LP, a publicly-held limited partnership that holds a 30 per cent interest in Northern Border and a 49 per cent interest in Tuscarora. TC PipeLines, LP was formed in 1998 to acquire, own and participate in the management of United States based pipeline investments and is managed by TransCanada. In 2000, TC PipeLines, LP increased its quarterly distribution by 5.6 per cent or US$0.10 per unit on an annualized basis compared to 1999.

In 2000, Northern Border received U.S. Federal Energy Regulatory Commission (FERC) approval to proceed with Project 2000, an extension of its existing system into Indiana. The project has an estimated cost of US$94 million and is expected to be in service in late 2001.

IROQUOIS / GREAT LAKES / NORTHERN BORDER TOLLING AGREEMENTS

In 2000, Iroquois, Great Lakes and Northern Border negotiated new long-term agreements with their shippers for terms of four, five and six years, respectively. These new agreements provide rate certainty and allow for greater operational flexibility, including the provision of new transmission services.

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.

TransCanada Pipeline Ventures

TransCanada Pipeline Ventures, which is 100 per cent owned by TransCanada, owns a 110 kilometre pipeline which supplies 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.

IROQUOIS EASTCHESTER EXPANSION

In 2000, Iroquois filed an application with the FERC to allow expansion and extension of its system into the Long Island, New York market. The estimated cost is US$170 million, with an expected in-service date of November 2002. The expansion will provide an additional 230 million cubic feet per day (MMcf/d) of new service into this under-supplied market.

MILLENNIUM PIPELINE PROJECT

TransCanada has a 21 per cent interest in the proposed Millennium Pipeline project in the United States and 100 per cent of the Canadian portion of the Lake Erie crossing. If approved, the proposed project would deliver 700 MMcf/d of natural gas from Dawn, Ontario to markets in New York. Applications have been filed with the FERC for the U.S. portion and the NEB for the Canadian portion. The NEB approval process for the Canadian portion has been adjourned pending further project progress.

NATURAL GAS DELIVERY VOLUMES

(billion cubic feet)	**2000**	1999	1998
Alberta System (1)	**4,490**	4,535	4,490
Canadian Mainline	**2,675**	2,684	2,610
BC System (1)	**408**	398	432
Great Lakes	**898**	937	931
Northern Border	**853**	835	826
Iroquois	**344**	345	330
Portland (2)	**40**	22	–
Tuscarora	**25**	24	25
Foothills	**1,186**	1,132	938
TQM	**168**	147	111
TransCanada Pipeline Ventures (2)	**36**	–	–

(1) Prior year amounts have been restated to conform with the current year's calculation methodology.

(2) Placed in service in 1999.

POWER

TransCanada's Power business represents one of the company's key growth areas. Power followed its strong earnings and operations growth in 1999 with continued growth in 2000.

Financial Review

TransCanada's Power business contributed net earnings of $105 million in 2000. This represents 21 per cent of TransCanada's consolidated net earnings from continuing operations in 2000 and is an increase of $65 million from 1999. A portion of this increase was due to the $23 million after-tax gain on the sale of TransCanada's interest in the Hermiston Power Partnership (Hermiston). The remaining $42 million increase over 1999 reflects:

- increased marketing and trading earnings from price volatility and increased customer demand;
- the acquisition of the remaining 29.9 per cent interest in Ocean State Power (OSP), and
- increased earnings from TransCanada Power, L.P. (Power LP) due to increased ownership, a full year's contribution from the Castleton and Williams Lake power plants which were acquired during 1999 and curtailment of certain plants during off-peak hours to sell the displaced gas at high market prices.

Power's 1999 net earnings of $40 million represented an increase of $11 million or 38 per cent, compared to $29 million in 1998. This increase was primarily due to strong results from the Westborough, Massachusetts power marketing office in its first full year of operation. Net earnings were also positively impacted by Power LP's acquisition of the Castleton and Williams Lake plants in 1999.

POWER LP

TransCanada manages, operates and is the largest limited partner in Power LP, which owns seven North American power plants.

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.

Calstock

TransCanada completed construction of an enhanced wood waste-fired power plant at Calstock, Ontario in mid-2000 and transferred it to Power LP in October 2000.

Castleton

In July 1999, Power LP acquired a combined-cycle plant located at Castleton-on-Hudson, New York, which also sells steam to an adjacent paper company.

Williams Lake

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

NOMINAL GENERATING CAPACITY OF POWER PLANTS

(megawatts)

TransCanada Power	
Ocean State	560
Carseland (1)	80
Redwater (1)	40
Cancarb	38
Gold Creek	6
Power LP (2)	
Williams Lake	66
Castleton	64
Tunis	43
Kapuskasing	40
Nipigon	40
North Bay	40
Calstock	35
Other	
Sundance (3)	560
	1,612

(1) Currently under construction.

(2) TransCanada holds a 41.6 per cent interest in Power LP.

(3) TransCanada buys 100 per cent of the Sundance A power plant output through a power purchase agreement.

POWER LP

TransCanada holds a 41.6 per cent interest in Power LP, a limited partnership and Canada's largest publicly-held power-based income fund, which owns six power plants in Canada and a seventh in the United States. TransCanada operates and provides fuel management services for each of these plants and provides overall management services to Power LP. These plants are fuelled by natural gas, waste heat, waste wood or a combination of the three. Since almost all of Power LP's natural gas fuel requirements are purchased through long-term contracts, TransCanada, as manager, has been able to capitalize on the current high natural gas prices for the benefit of Power LP. When economic conditions warrant, certain plants have been curtailed during off-peak hours to sell the displaced gas at high market prices, resulting in increased overall net income to Power LP.

TransCanada completed construction of the Calstock power plant in mid-2000 and transferred the plant to Power LP in October, 2000 after all testing requirements were met. The plant is a 35 megawatt

TRANSCANADA POWER

Ocean State

The 100 per cent owned Ocean State power plant in Rhode Island is a 560 MW natural gas-fired, combined-cycle facility.

Gold Creek

Fuelled by waste heat from TransCanada's adjacent compressor station in Grande Prairie, Alberta, the Gold Creek plant went into commercial operation in 1999.

Carseland and Redwater

Currently under construction in Carseland, Alberta and Redwater, Alberta, are natural gas-fired cogeneration plants with generation capacities of 80 MW and 40 MW, respectively. The plants are expected to be complete in late 2001.

Cancarb

In late 2000, TransCanada completed construction in Medicine Hat, Alberta of a 38 MW power plant that is fuelled by waste heat from the adjacent thermal carbon black facility. The plant is scheduled to be in service in the first quarter of 2001.

(MW) plant located at Calstock, Ontario, fuelled by a combination of waste wood from local lumber mills and waste heat from the adjacent TransCanada compressor station. In exchange for constructing the Calstock plant, TransCanada received 4.4 million Power LP units in 1998. These units were held in escrow and did not participate in distributions until the final plant transfer in October 2000, at which time TransCanada's participatory interest increased from 32.7 per cent to 41.6 per cent.

As a result of strong operating results at all plants, combined with the addition of the Calstock plant and a full year's contribution from the Castleton and Williams Lake power plants which were acquired in 1999, Power LP increased its annual distributions from $2.34 per unit in 1999 to $2.40 per unit in 2000.

NORTHEASTERN U.S. OPERATIONS

Through its power marketing office in Westborough, Massachusetts, Power dispatches its 560 MW OSP plant and Power LP's 64 MW Castleton plant in response to daily market conditions. Through long-term contracts, Power purchases 77 per cent of OSP's daily output and 100 per cent of the Castleton output for resale into the New England and New York markets. Most of this output is used to fulfill long-term market supply contract obligations in the New England area.

By controlling the dispatch levels of the gas-fired OSP and Castleton plants, Power capitalizes on the fluctuations in market demand and prices for both electricity and natural gas. This is accomplished by reducing plant output during periods of low electricity demand/prices and increasing output during periods of high electricity demand/prices. When market conditions warrant, Power reduces plant output and resells the displaced gas at high market prices, increasing its overall net earnings from these plants. This supply flexibility is fundamental to Power's continued growth and success in the deregulated New England and New York markets.

In October 2000, TransCanada acquired the remaining 29.9 per cent interest and now owns 100 per cent of OSP. TransCanada has assumed direct responsibility for operating OSP, allowing for further operating cost reductions and increased operational flexibility.

WESTERN MARKETING

From its Calgary office, TransCanada trades electricity across Canada and throughout the northern tier of the United States from Washington to Wisconsin. In these same markets, TransCanada also manages and supplies electricity requirements for various industrial customers on both margin and incentive fee bases.

In response to the strong demand from its industrial customers, and with the uncertainty surrounding the deregulation of the Alberta electricity market, TransCanada acquired a solid base of new supply for these customers through Alberta's two power auctions in 2000. In the first auction of Alberta power purchase agreements (PPA) in August 2000, TransCanada successfully acquired the 560 MW Sundance A Plant PPA for approximately $212 million. The Sundance PPA is a 17 year contract, which provides TransCanada with a long-term, low-cost supply from this plant. TransCanada has sold much of this output to industrial customers for terms of 5 to 17 years. Through these contracts and other market-based contracts, TransCanada has sold substantially all of its expected Sundance supply for 2001 and 80 per cent of its expected supply on average for the years 2002 to 2005.

In the Market Achievement Plan auction in December 2000, TransCanada acquired additional supply for the years 2001 to 2003. This supply is generated from a combination of the plants for which PPA's were not sold during the initial PPA auction. To reduce the company's exposure to price volatility, TransCanada has already resold 80 per cent of this supply during this three-year period.

To further the growth of its marketing and managed accounts businesses, TransCanada opened marketing offices in Toronto, Ontario and Omaha, Nebraska. Power expects to use its experience and knowledge from the Alberta and New England deregulation processes to identify and capitalize on opportunities presented during Ontario's deregulation process. The Omaha office will allow Power to more effectively pursue opportunities in the U.S. Midwest region and will complement its gas marketing operation in Omaha, thereby offering customers a broader range of services and products.

PLANT OPERATIONS

TransCanada has consistently operated its plants (and those operated for Power LP) on a low-cost basis while maintaining very high plant availability and safety levels. On average, TransCanada's power plants operated at 98 per cent availability in 2000, an increase from 97 per cent in 1999.

TransCanada has developed a core competency in effectively developing customer-focused cogeneration projects in the 40 to 200 MW range. TransCanada uses this competency to find solutions for industrial customers' needs for long-term, low-cost supply of electricity and heat/steam. As a result, TransCanada began construction in 2000 of two new gas-fired power plants in Alberta that will supply electricity and steam to the industrial customers' adjacent facilities. The first is an 80 MW plant located near Carseland and the second is a 40 MW plant located near Redwater. Both plants are scheduled to be completed in late 2001 and, in addition to meeting TransCanada's customers' needs, these plants will help meet Alberta's requirement for new supply in its currently tight electricity market.

ENVIRONMENT

While TransCanada's gas-fired power plants are profitable and provide customers with needed electricity, they are also environmentally beneficial. The biggest environmental benefit provided by TransCanada's plants is the recovery of waste heat gases that would otherwise be vented directly into the atmosphere. The recovered waste heat is utilized in the production of steam that is used for heating, industrial processes or generating additional electricity. This waste heat is sourced from the plants' other turbines and/or TransCanada's adjacent facilities/compressor stations.

Another key environmental benefit exists at the Williams Lake and Calstock plants, where the plants are largely fuelled by waste wood from local lumber mills. The waste wood is consumed to produce steam, which is used in the plants' steam turbines to generate electricity. Without these plants, the waste wood would otherwise be incinerated in traditional burners, which emit significant amounts of pollutant into the local atmosphere.

Outlook

TransCanada is committed to growing its Power business. Power has experienced an average annual growth in net earnings (excluding the gain on sale of Hermiston in 2000) of more than 50 per cent per year over the last three years. In this same three-year period, TransCanada, along with Power LP, added eight new plants and purchased the remaining equity interests in OSP as well as two of OSP's PPA interests.

TransCanada envisions growth continuing into the future. Power's growth strategy is customer/demand driven and is intended to develop opportunities created through deregulation and other means in its target markets with a specific focus on successfully growing its marketing businesses, developing new plants and pursuing new acquisitions. In 2000, TransCanada implemented this strategy with great success and will continue with this strategy in 2001 and beyond.

Business Risks

PLANT AVAILABILITY

One of the keys to Power's continued success is its commitment to excellent operating performance at each of its power plants, resulting in high plant availability and low operating costs. This same commitment will be applied in 2001 and future years.

FLUCTUATING MARKET PRICES

Power 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 (e.g. natural gas) as well as fluctuating supply and demand, which themselves are greatly affected by weather and consumer usage. 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 transaction 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 on page 35 and in Note 12 to the Consolidated Financial Statements.

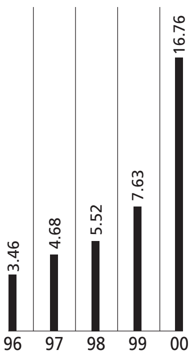
DEREGULATION

Much of the power industry in North America is currently undergoing deregulation, with various provinces and states at different stages in that process. TransCanada continues to monitor deregulation and seek related investment opportunities as they arise.

GAS MARKETING

TransCanada's gas marketing business is focused on natural gas supply, storage and asset management services in its key market areas in Canada and the northern tier of the United States.

Natural Gas Marketing Revenues*
(billions of dollars)



*Excluding Pan-Alberta, a business which was sold in December 1998.

Financial Review

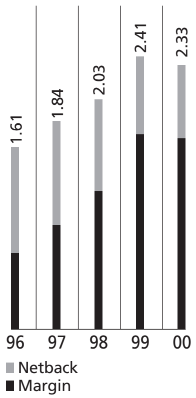
Gas Marketing recorded a net loss of $129 million in 2000, compared to a net loss of $5 million in 1999 and net earnings of $24 million in 1998. The net loss in 2000 is primarily due to after-tax losses of $124 million recognized on certain long-term natural gas contracts. In previous years, TransCanada entered into certain long-term natural gas contracts to support various corporate initiatives, including pipeline investments and downstream pipeline expansions. The profitability of these contracts was predicated on sustained historical price differentials between natural gas supply and market points. Over the past two years, the price differentials have narrowed and the company believes the decline in the value of these contracts is no longer temporary. As a result, TransCanada entered into third party arrangements and recognized losses of $124 million, after tax, in 2000 related to these long-term natural gas contracts.

The net loss from Gas Marketing for the year ended December 31, 2000, excluding the $124 million of losses recognized on certain long-term natural gas contracts, was $5 million, unchanged from 1999. The 2000 losses related to trading activities in the extremely volatile gas markets during the year and the bankruptcy of a third party U.S. gas storage operator. These were partly offset by earnings from other gas services. Higher revenues and cost of sales reflect higher natural gas prices in 2000 when compared to 1999.

Results for 1999 reflected the deterioration of the basis differential between the WCSB supply points and market areas. In addition, the 1999 results were negatively affected by unseasonably warm temperatures in the last quarter of 1999 compared to 1998 and the full-year impact of the sale of Pan-Alberta which occurred in December 1998.

TransCanada is one of the largest marketers of natural gas in North America. In 2000, the company sold approximately 6.4 Bcf/d of natural gas. This represents a decrease of approximately 0.2 Bcf/d compared to 1999, primarily due to the closure of the Houston office as part of TransCanada's efforts to focus on its core regions.

Natural Gas Marketing Volumes Sold*
(trillion cubic feet)



*Excluding Pan-Alberta, a business which was sold in December 1998.

Gas Marketing concentrates on client relationships with producers and end consumers by offering innovative products designed to meet customer needs. As the natural gas industry continually changes, TransCanada develops opportunities arising from product diversity, portfolio pricing and expertise. The benefits of this approach are seen in recent increases in the number of customers and the volumes sold within the company's core regions.

TransCanada also offers clients financial products that reduce the risk of fluctuating natural gas prices. These exposure-limiting products include physical transactions, swaps and options.

Approximately 22 per cent of TransCanada's natural gas marketing revenues in 2000 were generated from sales under a netback agreement with certain Alberta producers. The netback agreement provides for the purchase of natural gas in Alberta and its subsequent sale in Canada and the United States. TransCanada earns a marketing fee on the sale of natural gas under the netback agreement. TransCanada held restructuring discussions with producers over the past two years and implemented a series of changes in the management and structure of the netback pool. Agreement on a new fee structure, effective to November 2003, was approved in May 2000.

To facilitate discussions and build stronger relationships with producers, TransCanada created a Producer Advisory Committee, a forum for exchanging views on matters related to the operation and future direction of the netback pool. TransCanada and the Producer Advisory Committee are evaluating strategies and netback structure changes that will ensure continued balance between producer supply and markets.

Effective December 31, 2000, TransCanada retroactively adopted mark-to-market accounting for all of its energy trading contracts. Mark-to-market accounting better reflects the performance of TransCanada's marketing and trading businesses.

Outlook

TransCanada's 2001 goal is to develop incremental markets for Canadian gas throughout Canada and the northern tier of the United States, with a particular focus on markets that are or can be served by TransCanada's pipeline network. In addition, TransCanada will continue to develop innovative and sophisticated products to meet the needs of our larger customers in both producing and consuming regions. These products include innovative gas pricing and risk management structures and the management of transportation and storage assets. Gas Marketing continues to streamline its operating processes and shed unprofitable activities, and expects to increase its profitability by focusing on larger scale and higher value business opportunities. Increasingly, the products and services offered by Gas Marketing are seen as elements of TransCanada's overall service offering to gas transportation customers.

Business Risks

Net earnings from the Gas Marketing business are dependent upon a number of factors, including weather, pipeline operations, pipeline tariff structures and the impact of supply and demand on pricing differentials between supply and market points.

TransCanada enters into contracts for the direct purchase, transportation and sale of natural gas, where the principal risks are the price, performance and counterparty risks associated with these contracts. TransCanada manages these risks by matching physical positions to the extent possible and by using financial instruments, where appropriate. The company's risk management practices are described in the section on Risk Management on page 35 and in Note 12 to the Consolidated Financial Statements.

CORPORATE

In 2000, TransCanada met its financial objectives of improving discretionary cash flow, reducing leverage and growing earnings. This was accomplished through asset sales, reduced costs and debt repayment. Cash flows and net earnings in 2001 are expected to remain strong.

CORPORATE RESULTS-AT-A-GLANCE

Year ended December 31 *(millions of dollars)*	**2000**	1999	1998
General and administrative costs related to discontinued operations	**15**	17	15
Indirect financial and preferred equity charges	**113**	163	121
Interest income and other	**(51)**	(26)	(43)
	77	154	93
Restructuring and other costs	**–**	108	166
Net expenses, after tax	**77**	262	259

Financial Review

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

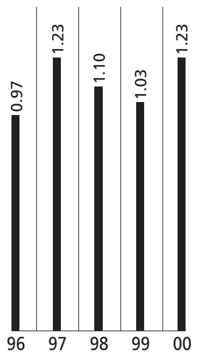
- general and administrative costs relating to services that support the discontinued operations.

  Corporate overhead costs are not allocated to discontinued operations. Rather, such costs reside in the Corporate segment. These costs will be eliminated as the divestitures of discontinued operations are completed.

- indirect financial and preferred equity charges.

  Direct financial charges are reported in the respective business segments. These direct financial charges are primarily associated with the debt and preferred securities related to the Alberta System and the Canadian Mainline. Certain indirect financial charges have been allocated to discontinued operations, most of which have now been sold. The remaining indirect financial charges reside in the Corporate segment.

Funds Generated from Continuing Operations
(billions of dollars)



- restructuring and other costs.

  As a result of TransCanada's change in strategic direction in 1999, restructuring and other costs related to continuing operations of $108 million, after tax, were recorded in 1999. This charge included costs related to reduction of employees, real estate and other provisions as well as asset impairments. In 1998, TransCanada recorded restructuring and other costs of $166 million, after tax, related to the business combination with NOVA.

Net expenses in the Corporate segment, excluding restructuring and other costs, were $77 million in 2000 compared to $154 million in 1999 and $93 million in 1998. The decrease in 2000 over 1999 is primarily due to lower financial and preferred equity charges as a result of lower net debt balances and the redemption of preferred shares. In addition, tax recoveries of $28 million were recorded in 2000 to reflect the impact of tax law and income tax rate changes. The increase in 1999 expenses over 1998 was due to higher financial and preferred equity charges. In 2000, asset sale proceeds from TransCanada's divestiture program were primarily used to reduce debt and this is expected to continue as additional proceeds are realized in 2001. Financial charges in 2001 will reflect a full year's impact of the 2000 debt reductions as well as additional debt reductions in 2001.

Liquidity and Capital Resources

CASH GENERATED FROM OPERATIONS

Funds generated from continuing operations were $1.2 billion for the year ended December 31, 2000, compared with $1.0 billion and $1.1 billion for 1999 and 1998, respectively. The Transmission business was the primary source of cash from operations for each of the three years.

INVESTING ACTIVITIES

Capital expenditures totalled $0.8 billion in 2000, a decrease of $1.0 billion compared to 1999. The major element of the 2000 capital spending program was maintenance of TransCanada's Transmission business, comprising $0.4 billion of the 2000 capital expenditures. The majority of the 1999 and 1998 capital spending related to the expansion of the Transmission business.

TransCanada realized proceeds of $2.2 billion in 2000 from the sale of non-core assets under the company's divestiture plan. These assets comprised the majority of the company's International business, its investment in the Express Pipeline System, the Canadian midstream business, and the petroleum and products marketing business. TransCanada's 1999 cash flows include proceeds from the disposition of non-core assets including ANGUS Chemical Company, the U.S. midstream facilities and East Australian Pipeline Limited, which generated cash flows of $658 million.

FINANCING ACTIVITIES

In 2000, TransCanada used proceeds on disposition of assets, along with cash flow from operations, to retire or repurchase $2.5 billion in long-term debt and preferred shares. This includes approximately $1.3 billion of open market debt repurchases, $0.7 billion of term debt maturities, $0.2 billion of debt related to assets that have been sold, and $0.3 billion of preferred share repurchases. The preferred shares carried approximately $16 million in annualized dividends. Dividends and preferred securities charges amounting to $536 million were paid in 2000 compared to $664 million in 1999.

In January 2001, TransCanada's Board approved an increase in the quarterly common share dividend payment from $0.20 per share to $0.225 per share for the quarter ending March 31, 2001.

Net cash provided by financing activities includes TransCanada's proportionate share of the change in non-recourse debt of joint ventures amounting to $122 million in 2000, reflecting non-recourse debt issued during the year, partially offset by repayments. Net cash provided by non-recourse joint venture debt activities was $13 million in 1999 compared to $748 million in 1998.

CREDIT ACTIVITIES

Unused lines of credit of $2.1 billion were available to support TransCanada's commercial paper program, secure energy commodity purchases and for general corporate purposes at December 31, 2000.

At December 31, 2000, $1.5 billion and US$750 million of medium-term notes could be issued under TransCanada's medium-term note programs in Canada and the United States, respectively.

Risk Management

TransCanada manages market risk exposures in accordance with corporate market risk policies and position limits. The policies and limits are designed to mitigate the risk of significant loss. The company's primary market risks result from volatility in commodity prices and interest and foreign currency exchange rates. TransCanada manages the impact of market risk exposure on earnings as well as the impact on the values of assets and liabilities. The company is also exposed to risk of loss due to 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.

NATURAL GAS AND POWER MARKETING PRICE RISK MANAGEMENT

The market risks of TransCanada's natural gas and power portfolios are managed by entering into offsetting physical positions, to the extent possible, to manage market risk exposures created by fixed and variable pricing arrangements, different pricing indices and different delivery points. Market risk is also managed through the use of 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 identifying offsetting positions or through the use of derivative financial instruments.

COUNTERPARTY RISK MANAGEMENT

Counterparty risk is comprised of a counterparty's ability to meet both its payment obligations in a timely manner and its performance obligations under the terms and conditions of the agreement or contract. Counterparty risk is mitigated by conducting financial assessments to establish a counterparty's creditworthiness, setting exposure limits and monitoring exposures against these limits, and, where warranted, obtaining financial assurances.

Accounting Changes

On January 1, 2000, TransCanada adopted the new standards of the Canadian Institute of Chartered Accountants with respect to accounting for income taxes and employee future benefits. Effective December 31, 2000, the company retroactively adopted mark-to-market accounting for all of the company's energy trading contracts. See Note 2 to the Consolidated Financial Statements.

FUTURE INCOME TAXES

Prior to January 1, 2000, the deferral method of accounting for income taxes had been used for the company's non-regulated operations. Under the new standard for future income taxes, the liability method of tax allocation is used. The new standard does not impact the company's regulated natural gas transmission businesses, for which the taxes payable method is used. This accounting change has been adopted retroactively, without restatement of prior periods.

EMPLOYEE FUTURE BENEFITS

The new standard for employee future benefits results in a new basis of calculating funding surpluses or deficiencies for pension benefits and the recognition of other post-employment benefits. Prior to January 1, 2000, the company recognized other post-employment benefits as paid. This accounting change was applied retroactively, without restatement of prior periods.

PRICE RISK MANAGEMENT

The mark-to-market accounting policy change has been applied retroactively with restatement of the prior year. This change in accounting policy was not applied to the 1998 financial statements because the information was not reasonably determinable.

DISCONTINUED OPERATIONS

Since December 1999, TransCanada has realized approximately $3.0 billion of sale proceeds, including $0.7 billion in January 2001. Based on actual results and revised estimates, a positive $200 million after-tax earnings adjustment was recorded in 2000.

Financial Review

In April 1999, the Board of Directors approved a plan (April Plan) to dispose of ANGUS Chemical Company (ANGUS), TransCanada's U.S. midstream business and the U.S. refined products and natural gas liquids marketing business. In December 1999, the Board of Directors approved a plan (December Plan) to dispose of the company's International business, its investment in the Express crude oil pipeline and related marketing business, the Canadian midstream business, Cancarb Limited and the petroleum and products marketing business.

These businesses are accounted for as discontinued operations. The assets and liabilities, net income/(loss) and cash provided from operations are presented as discontinued operations in the Consolidated Financial Statements and comparative periods were restated.

The company recorded a net loss from discontinued operations in 1999 of $524 million. This amount includes a net gain of $20 million related to the April Plan, which was substantially completed in 1999, a net loss of $439 million related to the December Plan, asset impairments of $159 million and earnings prior to plan approval of $54 million.

The December Plan has been substantially completed in 2000, and based on actual results and revised estimates, a positive $200 million after-tax adjustment was recorded. This adjustment is primarily due to proceeds in excess of the company's original estimate. Further adjustments to the estimate of the net loss on disposal will be recognized as a gain or loss on discontinued operations in the period such changes are determined.

Disposition Status

Since December 1999, TransCanada has realized approximately $3.0 billion of proceeds from the sale of non-core assets, including $0.7 billion in January 2001. An additional $0.4 billion of divestitures has been signed and announced. Included in this amount are proceeds of approximately $160 million for TransCanada's planned sale of Cancarb Limited and the associated power plant which was not completed as scheduled. The company is considering its business options and legal remedies regarding the sale.

Proceeds received to date have been used mainly to reduce debt and associated financial charges and this is expected to continue as additional proceeds are received. In 2000, TransCanada retired or repurchased approximately $2.5 billion of term debt and preferred shares.

With the divestiture program substantially completed and the balance sheet strengthened, TransCanada is focused on its core businesses of natural gas transmission, power, and natural gas marketing in Canada and the northern tier of the United States.

FORWARD-LOOKING INFORMATION

Certain information in this Management's Discussion and Analysis (MD&A) is forward-looking information and relates to, among other things, targeted cost savings, anticipated financial performance, business prospects and strategies. Forward-looking information typically contains statements with words such as "anticipate", "believe", "expect", "plan", "target" or similar words suggesting future outcomes. By their nature, such statements are subject to various risks and uncertainties, which could cause TransCanada's actual results and experience to differ materially from the anticipated results. Such risks and uncertainties include, but are not limited to: availability and price of energy commodities; regulatory decisions; the ability of TransCanada to successfully implement the initiatives referred to in this MD&A; management's ability to execute the disposition of its remaining discontinued operations; competitive factors and pricing pressures, and overcapacity in the pipeline industry. For further information on additional risks and uncertainties, you are advised to consult TransCanada's Annual Information Form under the heading "Forward-Looking Information".

2000 CONSOLIDATED FINANCIAL STATEMENTS
REPORT OF MANAGEMENT

The consolidated financial statements included in the 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). The MD&A is based on the Company's financial results prepared in accordance with Canadian GAAP. It compares the Company's financial performance in 2000 to 1999 and should be read in conjunction with the consolidated financial statements and accompanying notes. In addition, significant changes between 1999 and 1998 are highlighted. Note 21 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. 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.

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 generally accepted accounting principles in Canada. The report of KPMG LLP on page 44 outlines the scope of their examination and their opinion on the consolidated financial statements.

Douglas D. Baldwin	Russell K. Girling
President and	*Executive Vice-President and*
Chief Executive Officer	*Chief Financial Officer*

January 29, 2001

CONSOLIDATED INCOME

Year ended December 31 (millions of dollars except per share amounts)	**2000**	1999	1998
Revenues	**21,156**	11,856	10,960
Operating Expenses			
Cost of sales	**17,240**	7,809	6,845
Other costs and expenses	**1,415**	1,509	1,679
Depreciation	**740**	692	636
Restructuring and other costs (Note 18)	**–**	170	207
	19,395	10,180	9,367
Operating Income	**1,761**	1,676	1,593
Other Expenses/(Income)			
Financial charges (Note 7)	**959**	1,018	974
Financial charges of joint ventures (Note 8)	**113**	120	121
Allowance for funds used during construction	**(8)**	(46)	(80)
Interest and other income	**(114)**	(40)	(64)
Gain on sale of assets	**(37)**	(91)	–
	913	961	951
Income from Continuing Operations before Income Taxes	**848**	715	642
Income Taxes (Note 13)	**258**	173	179
Net Income from Continuing Operations	**590**	542	463
Net Income/(Loss) from Discontinued Operations (Note 19)	**200**	(524)	(31)
Net Income	**790**	18	432
Preferred Securities Charges (Note 9)	**44**	46	21
Preferred Share Dividends	**35**	52	50
Net Income/(Loss) Applicable to Common Shares	**711**	(80)	361
Net Income/(Loss) Applicable to Common Shares			
Continuing operations	**511**	444	392
Discontinued operations	**200**	(524)	(31)
	711	(80)	361
Net Income/(Loss) Per Share (Note 11)			
Continuing operations	**$ 1.08**	$ 0.95	$ 0.85
Discontinued operations	**0.42**	(1.12)	(0.07)
	$ 1.50	$ (0.17)	$ 0.78

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

CONSOLIDATED CASH FLOWS

Year ended December 31 (millions of dollars)	**2000**	1999	1998
Cash Generated from Operations			
Net income from continuing operations	**590**	542	463
Depreciation	**740**	692	636
Net unrealized loss on energy trading contracts (Note 12)	**87**	11	–
Restructuring and other costs	**–**	38	109
Gain on sale of assets	**(37)**	(91)	–
Future income taxes	**49**	(113)	(62)
Power purchase agreement payment	**(212)**	–	–
Other	**9**	(46)	(46)
Funds generated from continuing operations	**1,226**	1,033	1,100
Decrease in operating working capital (Note 16)	**206**	133	190
Net cash provided by continuing operating activities	**1,432**	1,166	1,290
Net cash provided by discontinued operating activities	**288**	130	102
	1,720	1,296	1,392
Investing Activities			
Capital expenditures	**(812)**	(1,824)	(3,653)
Acquisitions, net of cash acquired	**(111)**	(56)	(438)
Disposition of assets	**2,233**	658	–
Deferred amounts and other	**(31)**	42	16
Net cash provided by/(used in) investing activities	**1,279**	(1,180)	(4,075)
Financing Activities			
Dividends and preferred securities charges	**(536)**	(664)	(538)
Notes payable repaid, net	**(25)**	(228)	(428)
Long-term debt issued	**–**	1,204	2,524
Reduction of long-term debt	**(2,139)**	(699)	(390)
Non-recourse debt of joint ventures issued	**404**	161	826
Reduction of non-recourse debt of joint ventures	**(282)**	(148)	(78)
Partnership units issued	**–**	312	127
Preferred securities issued	**–**	–	672
Preferred shares issued	**–**	194	195
Preferred shares redeemed	**(328)**	(396)	–
Common shares issued	**5**	204	184
Transaction costs of business combination	**–**	–	(182)
Net cash (used in)/provided by financing activities	**(2,901)**	(60)	2,912
Increase in Cash and Short-Term Investments	**98**	56	229
Cash and Short-Term Investments			
Beginning of year	**411**	355	126
Cash and Short-Term Investments			
End of year	**509**	411	355

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

CONSOLIDATED BALANCE SHEET

December 31 (millions of dollars)	2000	1999
ASSETS		
Current Assets		
Cash and short-term investments	**509**	411
Accounts receivable	**2,043**	1,059
Inventories	**311**	351
Other	**32**	26
Unrealized gains on energy trading contracts (Note 12)	**2,334**	153
Current assets of discontinued operations (Note 19)	**154**	873
	5,383	2,873
Unrealized Gains on Energy Trading Contracts (Note 12)	**521**	63
Long-Term Investments (Note 6)	**174**	417
Plant, Property and Equipment (Notes 4, 7 and 8)	**17,673**	17,738
Other Assets	**422**	204
Future Income Taxes (Note 13)	**192**	143
Long-Term Assets of Discontinued Operations (Note 19)	**1,183**	3,531
	25,548	24,969
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable (Note 14)	**200**	214
Accounts payable	**2,579**	1,410
Accrued interest	**264**	284
Long-term debt due within one year (Note 7)	**612**	603
Non-recourse debt of joint ventures due within one year (Note 8)	**29**	64
Provision for loss on discontinued operations (Note 19)	**128**	464
Unrealized losses on energy trading contracts (Note 12)	**2,341**	157
Current liabilities of discontinued operations (Note 19)	**98**	579
	6,251	3,775
Unrealized Losses on Energy Trading Contracts (Note 12)	**608**	66
Deferred Amounts	**344**	381
Long-Term Debt (Note 7)	**9,928**	11,591
Non-Recourse Debt of Joint Ventures (Note 8)	**1,296**	1,272
Junior Subordinated Debentures (Note 9)	**243**	241
Long-Term Liabilities of Discontinued Operations (Note 19)	**288**	788
Non-Controlling Interests	**2**	243
	18,960	18,357
Shareholders' Equity		
Preferred securities (Note 9)	**969**	960
Preferred shares (Note 10)	**389**	717
Common shares (Note 11)	**4,540**	4,535
Contributed surplus	**263**	263
Retained earnings	**414**	119
Foreign exchange adjustment (Note 12)	**13**	18
	6,588	6,612
Commitments and Contingencies (Note 17)		
	25,548	24,969

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

On behalf of the Board:

Director

Director

CONSOLIDATED RETAINED EARNINGS

Year ended December 31 (millions of dollars)	**2000**	1999	1998
Balance at beginning of year	**119**	740	2,791
Net income	**790**	18	432
Preferred securities charges	**(44)**	(46)	(21)
Preferred share dividends	**(35)**	(52)	(50)
Common share dividends	**(379)**	(527)	(490)
Split off of commodity chemicals business (Note 20)	**–**	–	(1,708)
Transaction costs of business combination (Note 20)	**–**	–	(182)
Accounting changes (Note 2)	**(37)**	(3)	–
Other	**–**	(11)	(32)
	414	119	740

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, 2000 and 1999 and the consolidated statements of income, retained earnings and cash flows for each of the years in the three-year period ended December 31, 2000. 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, 2000 and 1999 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2000 in accordance with Canadian generally accepted accounting principles.

Accounting principles generally accepted in Canada vary in certain significant respects from accounting principles generally accepted in the United States. Application of accounting principles generally accepted in the United States would have affected results of operations for each of the years in the three-year period ended December 31, 2000 and shareholders' equity as at December 31, 2000 and 1999, to the extent summarized in Note 21 to the consolidated financial statements.

KPMG LLP

Chartered Accountants

Calgary, Canada

January 29, 2001

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

TransCanada PipeLines Limited (the Company or TransCanada) is one of the largest energy companies and carriers of natural gas in North America. TransCanada operates in three segments representing separately managed strategic business units, 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), the 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 energy transmission facilities in Canada and the United States.

POWER

The Power business builds, owns and operates electrical power plants, markets and trades electricity and provides electricity-managed account services to energy and industrial customers. This business operates in both Canada and the United States.

GAS MARKETING

The Gas Marketing business purchases and sells natural gas on its own behalf and under netback pricing arrangements with Western Canada Sedimentary Basin producers. The Gas Marketing business also provides a selection of supply, storage and transportation services, as well as structured financial products and services, to its customers in Canada and the northern tier of 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 21. 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. Other investments are carried at cost.

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, operations and accounting. The natural gas pipelines in the United States and the Ocean State Power plant 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 are considered to be cash equivalents and are recorded at cost, which approximates market value.

INVENTORIES

Natural gas trading inventory is carried at market value and other 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 using rates approved by the regulators. 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.

Other

Plant, property and equipment are recorded at cost and depreciated on the straight-line basis over estimated service lives at average annual rates generally ranging from three to five per cent. Interest is capitalized on plant under construction and included in the cost.

INCOME TAXES

For tollmaking purposes, the taxes payable method of accounting for income taxes is used for Canadian natural gas transmission operations. 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 recovered in revenues at that time.

The liability method of accounting for income taxes is used for other 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 related to the Alberta System and the Canadian Mainline are deferred until they are recovered in tolls.

PRICE RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Company engages in price risk management activities for both trading and non-trading purposes. Trading activities consist of goods and services provided to the energy sector by the Company's gas and power marketing operations. All energy trading activities are accounted for using the mark-to-market method. Trading activities are conducted through a variety of instruments with third parties, including contracts for physical delivery of an energy commodity, exchange traded futures contracts involving cash settlements, forward contracts involving cash settlement or physical delivery, swap contracts which require payments to (or receipts from) counterparties based on the differential between fixed and variable prices for commodities, exchange-traded and over-the-counter options, and other contractual arrangements.

Under the mark-to-market method of accounting, energy trading contracts are recorded at fair values in the Consolidated Balance Sheet. Changes in the balance sheet accounts result primarily from changes in the valuation of the portfolio of contracts, new transactions and the maturity and settlement of certain contracts. The market prices used to value these transactions reflect Management's best estimate considering various factors including closing exchange and over-the-counter quotations, time value and volatility factors underlying the commitments. The values are adjusted to reflect the potential impact of liquidating the Company's position in an orderly manner over a reasonable period of time under present market conditions and to reflect other types of risk, including credit risk.

Net unrealized gains and losses recognized in a period are included in revenues in the Consolidated Statement of Income. They result primarily from transactions originating within that period, contract restructurings and the impact of price movements. Cash inflows and outflows associated with energy trading contracts are recognized in cash from operations as the settlement of transactions occurs.

The Company also utilizes derivative and other financial instruments in connection with non-trading activities to manage its exposure to changes in foreign currency exchange rates and interest rates. 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 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 both defined benefit and defined contribution 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. 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.

NOTE 2

Accounting Changes

Effective January 1, 2000, the Company adopted the new standards of the Canadian Institute of Chartered Accountants with respect to accounting for income taxes and employee future benefits. Effective December 31, 2000, the Company adopted mark-to-market accounting for all of the Company's energy trading contracts.

FUTURE INCOME TAXES

Under the new standard for future income taxes, the liability method of tax allocation is used. Previously, the Company used the deferral method for its non-regulated businesses. The new standard does not impact the accounting for income taxes in the Company's regulated gas transmission businesses.

This accounting change was applied retroactively, without restatement of prior periods. This resulted in a decrease in each of retained earnings and future income tax assets of $65 million. The impact of this accounting change on earnings for the year ended December 31, 2000 was primarily tax recoveries of $28 million reflecting substantively enacted tax law and income tax rate changes.

EMPLOYEE FUTURE BENEFITS

The new standard for employee future benefits results in a new basis of calculating funding surpluses or deficiencies for pension benefits and the recognition of other post-employment benefits in the financial statements. Previously, the Company recognized other post-employment benefits as paid. This accounting change was applied retroactively, without restatement of prior periods. This resulted in an increase in retained earnings and a decrease in deferred amounts of $28 million. The effect of this change on earnings for the year ended December 31, 2000 was not significant.

PRICE RISK MANAGEMENT

The mark-to-market accounting policy change has been applied retroactively with restatement of the prior year. This change in accounting policy was not applied to the 1998 financial statements because the information was not reasonably determinable. The cumulative effect of this change on retained earnings as at January 1, 1999 was a decrease of $3 million. The net unrealized loss on energy trading contracts in the year ended December 31, 2000 was $87 million, before tax, comprised of a net unrealized gain of $37 million, before tax, in the Power business and a net unrealized loss of $124 million, before tax, in the Gas Marketing business.

The significant impacts of the accounting change on the Consolidated Balance Sheet and Consolidated Statement of Income as at and for the year ended December 31, 1999 are as follows.

(millions of dollars)	Increase/(Decrease)
Consolidated Balance Sheet	
Unrealized gains on energy trading contracts	
Current asset	153
Long-term asset	63
Unrealized losses on energy trading contracts	
Current liability	157
Long-term liability	66
Retained earnings	(13)
Consolidated Income	
Revenues	(17)
Income taxes	(7)

NOTE 3

Segmented Information

NET INCOME/(LOSS)[1]

	Transmission	Power	Gas Marketing	Corporate	Total
Year ended December 31, 2000 (millions of dollars)					
Revenues	**3,830**	**565**	**16,761**	**–**	**21,156**
Cost of sales	**–**	**(288)**	**(16,952)**	**–**	**(17,240)**
Other costs and expenses	**(1,246)**	**(101)**	**(43)**	**(25)**	**(1,415)**
Depreciation	**(697)**	**(35)**	**(7)**	**(1)**	**(740)**
Operating income/(loss)	**1,887**	**141**	**(241)**	**(26)**	**1,761**
Financial and preferred equity charges	**(877)**	**(3)**	**–**	**(158)**	**(1,038)**
Financial charges of joint ventures	**(101)**	**(12)**	**–**	**–**	**(113)**
Other income	**52**	**9**	**7**	**54**	**122**
Gain on sale of assets	**11**	**26**	**–**	**–**	**37**
Income taxes	**(360)**	**(56)**	**105**	**53**	**(258)**
Continuing Operations	**612**	**105**	**(129)**	**(77)**	**511**
Discontinued Operations					**200**
Net Income Applicable to Common Shares					**711**
Year ended December 31, 1999 (millions of dollars)					
Revenues	3,774	450	7,632	–	11,856
Cost of sales	–	(234)	(7,575)	–	(7,809)
Other costs and expenses	(1,299)	(119)	(61)	(30)	(1,509)
Depreciation	(657)	(30)	(2)	(3)	(692)
Restructuring and other costs	–	–	–	(170)	(170)
Operating income/(loss)	1,818	67	(6)	(203)	1,676
Financial and preferred equity charges	(876)	–	(2)	(238)	(1,116)
Financial charges of joint ventures	(107)	(13)	–	–	(120)
Other income	46	9	2	29	86
Gain on sale of assets	91	–	–	–	91
Income taxes	(301)	(23)	1	150	(173)
Continuing Operations	671	40	(5)	(262)	444
Discontinued Operations					(524)
Net Loss Applicable to Common Shares					(80)
Year ended December 31, 1998 (millions of dollars)					
Revenues	3,613	290	7,057	–	10,960
Cost of sales	–	(190)	(6,655)	–	(6,845)
Other costs and expenses	(1,271)	(32)	(349)	(27)	(1,679)
Depreciation	(608)	(24)	(3)	(1)	(636)
Restructuring and other costs	–	–	–	(207)	(207)
Operating income/(loss)	1,734	44	50	(235)	1,593
Financial and preferred equity charges	(857)	(1)	–	(187)	(1,045)
Financial charges of joint ventures	(111)	(10)	–	–	(121)
Other income/(expenses)	94	7	(3)	46	144
Income taxes	(262)	(11)	(23)	117	(179)
Continuing Operations	598	29	24	(259)	392
Discontinued Operations					(31)
Net Income Applicable to Common Shares					361

(1) In determining the net income of each segment, restructuring and other costs as well as certain expenses such as indirect financial charges and related income taxes are not allocated to business segments.

TOTAL ASSETS

December 31 (millions of dollars)	**2000**	1999
Transmission	**17,347**	18,269
Power	**1,889**	517
Gas Marketing (primarily current assets)	**3,892**	993
Corporate	**1,083**	786
Continuing Operations	**24,211**	20,565
Discontinued Operations	**1,337**	4,404
	25,548	24,969

GEOGRAPHIC INFORMATION

Year ended December 31 (millions of dollars)	**2000**	1999	1998
Revenues[(2)]			
Canada – domestic	**13,077**	5,479	5,091
Canada – export	**2,888**	3,024	2,013
United States	**5,191**	3,353	3,856
	21,156	11,856	10,960

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

December 31 (millions of dollars)	**2000**	1999
Plant, Property and Equipment		
Canada	**16,089**	16,220
United States	**1,584**	1,518
	17,673	17,738

CAPITAL EXPENDITURES

Year ended December 31 (millions of dollars)	**2000**	1999	1998
Transmission	**354**	1,186	2,369
Power	**104**	117	72
Gas Marketing and Corporate	**60**	20	4
Continuing Operations	**518**	1,323	2,445
Discontinued Operations	**294**	501	1,208
	812	1,824	3,653

NOTE 4

Plant, Property and Equipment

	2000			1999
December 31 (millions of dollars)	**Cost**	**Accumulated Depreciation**	**Net Book Value**	Net Book Value
Transmission				
Alberta System				
Pipeline	**4,612**	**1,420**	**3,192**	3,249
Compression	**1,396**	**327**	**1,069**	1,111
Metering and other	**1,203**	**337**	**866**	853
	7,211	**2,084**	**5,127**	5,213
Under construction	**53**	**–**	**53**	70
	7,264	**2,084**	**5,180**	5,283
Canadian Mainline				
Pipeline	**8,627**	**2,495**	**6,132**	6,288
Compression	**3,374**	**647**	**2,727**	2,690
Metering and other	**427**	**118**	**309**	289
	12,428	**3,260**	**9,168**	9,267
Under construction	**34**	**–**	**34**	119
	12,462	**3,260**	**9,202**	9,386
North American pipelines and other	**3,721**	**1,303**	**2,418**	2,485
	23,447	**6,647**	**16,800**	17,154
Power	**1,045**	**320**	**725**	492
Gas Marketing and Corporate	**206**	**58**	**148**	92
	24,698	**7,025**	**17,673**	17,738

NOTE 5

Joint Venture Investments

		TransCanada's Proportionate Share				
		Income/(Loss) Before Income Tax Year ended December 31			Net Assets December 31	
(millions of dollars)	Ownership Interest	**2000**	1999	1998	**2000**	1999
Great Lakes	50.0%	**84**	85	86	**433**	519
Northern Border	(1)	**–**	21	46	**–**	–
Iroquois	35.0% (2)	**22**	20	23	**88**	113
Tuscarora	17.4% (3)	**4**	5	4	**9**	22
Foothills	50.0 – 74.5%	**33**	29	22	**204**	199
Trans Québec & Maritimes	50.0%	**14**	13	12	**82**	84
Ocean State Power	(4)	**22**	29	26	**–**	184
TransCanada Power, L.P.	41.6% (5)	**21**	17	16	**236**	227
TC PipeLines, LP	33.4% (6)	**5**	–	–	**104**	–
Other	25.0 – 60.0%	**11**	7	(2)	**34**	37
		216	226	233	**1,190**	1,385

(1) The Company's 30.0 per cent investment in Northern Border was sold to TC PipeLines, LP in May 1999 (see Note 6).

(2) During 1999, the Company increased its interest in Iroquois from 29.0 per cent to 35.0 per cent.

(3) During 2000, the Company sold a 49.0 per cent interest in Tuscarora Gas Transmission Company to TC PipeLines, LP, which resulted in the Company retaining a total investment of 17.4 per cent.

(4) During 1998, the Company increased its interest in the Ocean State Power plant from 40.0 per cent to 70.1 per cent. In October 2000, the Company increased its interest to 100 per cent and the investment was consolidated subsequent to that date.

(5) During 1998, the Company decreased its interest in TransCanada Power, L.P. from 50.0 per cent to 39.8 per cent with a further decrease to 32.7 per cent in 1999. During 2000, the Company increased its interest to 41.6 per cent.

(6) In September 2000, the accounting treatment for TC PipeLines, LP changed from consolidation to proportionate consolidation as a result of a change in the control relationship.

Consolidated retained earnings at December 31, 2000 include undistributed earnings from these joint ventures of $267 million (1999 – $383 million).

SUMMARIZED FINANCIAL INFORMATION OF JOINT VENTURES

Year ended December 31 (millions of dollars)	2000	1999	1998
Income			
Revenues	**603**	606	716
Costs and expenses	**(155)**	(139)	(263)
Depreciation	**(132)**	(138)	(137)
Joint venture financial charges and other	**(100)**	(103)	(83)
Proportionate share of income before income taxes of joint ventures	**216**	226	233

Year ended December 31 (millions of dollars)	2000	1999	1998
Cash Flows			
Operations	**321**	298	342
Investing activities	**(80)**	(274)	(999)
Financing activities	**(240)**	(61)	738
Proportionate share of increase/(decrease) in cash and short-term investments of joint ventures	**1**	(37)	81

December 31 (millions of dollars)	2000	1999
Balance Sheet		
Cash and short-term investments	**66**	65
Other current assets	**75**	47
Long-term investments	**123**	–
Plant, property and equipment	**2,492**	2,714
Other assets and deferred amounts	**(33)**	59
Current liabilities	**(167)**	(114)
Non-recourse debt	**(1,296)**	(1,272)
Future income taxes	**(70)**	(114)
Proportionate share of net assets of joint ventures	**1,190**	1,385

NOTE 6

Long-Term Investments

December 31 (millions of dollars)	2000	1999
Equity Investments		
Northern Border	**123**	361
Other	**51**	56
	174	417

The Company holds a 33.4 per cent interest in TC PipeLines, LP, which holds a 30.0 per cent interest in Northern Border Pipeline Company. In September 2000, the accounting treatment for TC PipeLines, LP changed from consolidation to proportionate consolidation as a result of a change in the control relationship.

Consolidated retained earnings at December 31, 2000 include undistributed earnings from these equity investments of $21 million (1999 – $21 million).

NOTE 7

Long-Term Debt

	Maturity Dates	2000 Outstanding December 31[1]	2000 Weighted Average Interest Rate[2]	1999 Outstanding December 31[1]	1999 Weighted Average Interest Rate[2]
Alberta System					
Debentures and Notes					
Canadian dollars	2003 to 2024	**840**	**11.1%**	861	11.1%
U.S. dollars (2000 and 1999 – US$625)	2002 to 2023	**938**	**8.2%**	902	8.2%
Medium-Term Notes					
Canadian dollars	2001 to 2030	**791**	**7.4%**	981	7.4%
U.S. dollars (2000 and 1999 – US$333)	2001 to 2029	**499**	**7.3%**	481	7.3%
Unsecured Loans					
U.S. dollars (2000 – US$107; 1999 – US$182)	2003	**160**	**7.1%**	263	6.4%
		3,228		3,488	
Foreign exchange differential recoverable through the tollmaking process		**(254)**		(218)	
		2,974		3,270	
Canadian Mainline					
First Mortgage Pipe Line Bonds					
Pounds Sterling (2000 and 1999 – £25)	2007	**56**	**16.5%**	58	16.5%
Debentures					
Canadian dollars	2002 to 2020	**1,455**	**10.9%**	1,530	10.9%
U.S. dollars (2000 and 1999 – US$800)	2012 to 2023	**1,200**	**9.2%**	1,155	9.2%
Medium-Term Notes					
Canadian dollars	2001 to 2031	**2,932**	**7.1%**	3,017	7.1%
U.S. dollars (2000 and 1999 – US$120)	2010	**180**	**6.1%**	173	6.1%
		5,823		5,933	
Foreign exchange differential recoverable through the tollmaking process		**(250)**		(200)	
		5,573		5,733	
Other					
Medium-Term Notes					
Canadian dollars	2005 to 2030	**342**	**6.6%**	745	7.0%
U.S. dollars (2000 – US$785; 1999 – US$1,363)	2001 to 2029	**1,178**	**6.8%**	1,967	6.8%
Subordinated Debentures					
U.S. dollars (2000 – US$57; 1999 – US$200)	2006	**86**	**9.1%**	289	9.1%
Long-Term Debt of Subsidiaries					
U.S. dollars (2000 – US$138; 1999 – US$7)	2002 to 2011	**207**	**8.2%**	10	7.4%
Unsecured Loans					
Canadian dollars	2001 to 2003	**180**	**7.6%**	180	7.6%
		1,993		3,191	
		10,540		12,194	
Less: Long-Term Debt Due Within One Year		**612**		603	
		9,928		11,591	

(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 debentures and notes – 8.2 per cent (1999 – 8.2 per cent); Alberta System Canadian dollar medium-term notes – 7.3 per cent (1999 – 6.9 per cent); Alberta System U.S. dollar unsecured loans – 8.3 per cent (1999 – 7.9 per cent); and Other U.S. dollar subordinated debentures – 8.6 per cent (1999 – 8.9 per cent).

MANDATORY RETIREMENTS

Mandatory retirements resulting from maturities and sinking fund obligations of the long-term debt of the Company approximate: 2001 – $612 million; 2002 – $518 million; 2003 – $536 million; 2004 – $355 million and 2005 – $354 million.

MEDIUM-TERM NOTES

The Company has established medium-term note programs in Canada and the United States. At December 31, 2000, the Company can issue additional medium-term notes of up to $1.5 billion in Canada and US$750 million in the United States under these existing programs.

ALBERTA SYSTEM

Debentures

Debentures amounting to $225 million have retraction provisions which entitle the holders to require redemption of up to 8 per cent of the principal plus accrued and unpaid interest on repayment dates beginning in 1997. No note holders have required redemption.

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 $148 million have retraction provisions which entitle the holders to require redemption of the principal plus accrued and unpaid interest on repayment dates varying from 2001 to 2003. Medium-term notes amounting to $125 million have a provision entitling the holders to extend the maturity of the medium-term notes from the initial repayment date of 2001 to 2008. If extended, the interest rate would increase from 5.6 per cent to 5.9 per cent and the medium-term notes would become redeemable at the option of the Company.

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 U.S. Treasury 30 year bond yield.

FINANCIAL CHARGES

Year ended December 31 (millions of dollars)	**2000**	1999	1998
Interest on long-term debt	**974**	1,026	960
Regulatory deferrals and amortizations	**(13)**	6	12
Short-term interest and other financial charges	**47**	59	67
Interest capitalized	**–**	(1)	(10)
	1,008	1,090	1,029
Financial charges – discontinued operations	**(49)**	(72)	(55)
	959	1,018	974

The Company made interest payments of $1,024 million, $1,062 million and $981 million for the years ended December 31, 2000, 1999 and 1998, respectively.

NOTE 8

Non-Recourse Debt of Joint Ventures

	Maturity Dates	2000 Outstanding December 31[1]	2000 Weighted Average Interest Rate[2]	1999 Outstanding December 31[1]	1999 Weighted Average Interest Rate[2]
Great Lakes					
Senior Unsecured Notes					
(2000 – US$297; 1999 – US$257)	2003 to 2030	**446**	**8.2%**	371	8.2%
Iroquois					
Bank Loan					
(2000 – US$136; 1999 – US$118)	2009 to 2010	**204**	**8.1%**	170	8.7%
Tuscarora					
Senior Secured Notes					
(2000 – US$14; 1999 – US$43)	2010	**21**	**7.2%**	62	7.1%
Foothills					
Senior Unsecured Notes	2005	**343**	**5.6%**	345	4.9%
Senior Secured Notes	2005	**65**	**8.4%**	66	8.4%
Trans Québec & Maritimes					
First Mortgage Bonds	2005 to 2010	**143**	**7.3%**	136	8.6%
Ocean State Power[3]					
Senior Secured Notes					
(1999 – US$91)	2001 to 2011	**–**	**–**	131	7.8%
TransCanada Power, L.P.					
Bank Loan	2014	**66**	**6.4%**	53	5.9%
TC PipeLines, LP					
Senior Unsecured Notes					
(2000 – US$7; 1999 – nil)	2003	**11**	**7.6%**	–	–
Other					
Note	2001	**6**	**6.9%**	2	6.5%
Bank Loan	2001 to 2006	**20**	**7.0%**	–	–
		1,325		1,336	
Less: Non-Recourse Debt of Joint Ventures Due Within One Year		**29**		64	
		1,296		1,272	

(1) Amounts outstanding 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. The effective weighted average interest rates on the bank loans of Iroquois, Foothills and TransCanada Power, L.P. resulting from swap agreements are 7.8 per cent, 6.7 per cent, and 7.5 per cent, respectively, at December 31, 2000. The effective weighted average interest rates on these bank loans resulting from swap agreements were 7.6 per cent, 6.5 per cent and 7.5 per cent, respectively, at December 31, 1999.

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

The debt of joint ventures is non-recourse to TransCanada. The security provided by each joint venture is limited to the rights and assets of that joint venture and does not extend to the rights and assets of TransCanada, except to the extent of TransCanada's investment.

The Company's proportionate share of mandatory retirements resulting from maturities and sinking fund obligations of the non-recourse joint venture debt approximates: 2001 – $29 million; 2002 – $43 million; 2003 – $389 million; 2004 – $36 million and 2005 – $144 million.

FINANCIAL CHARGES OF JOINT VENTURES

Year ended December 31 (millions of dollars)	**2000**	1999	1998
Interest on long-term non-recourse debt	**149**	139	137
Other	**5**	10	10
	154	149	147
Financial charges of joint ventures – discontinued operations	**(41)**	(29)	(26)
	113	120	121

The Company's proportionate share of the interest payments of joint ventures in continuing operations is $99 million, $78 million and $86 million for the years ended December 31, 2000, 1999 and 1998, respectively.

NOTE 9

Junior Subordinated Debentures and Preferred Securities

December 31 (millions of dollars)	Maturity Dates	**2000**	1999
Junior Debentures			
8.75% Issue (2000 and 1999 – US$160 million)	2045	**218**	218
Preferred Securities			
8.25% and 8.50% Issues			
(2000 – US$17 million; 1999 – US$15 million)	2045 to 2047	**25**	23
		243	241

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

JUNIOR DEBENTURES

The Junior Debentures are redeemable at par by the Company at any time on or after July 23, 2001 and, in certain circumstances, prior to that date. The Company may elect to defer interest payments on the Junior Debentures. Interest and deferred interest, if any, are payable in cash.

PREFERRED SECURITIES

The US$200 million 8.50 per cent Preferred Securities are redeemable by the Company at par at any time on or after November 7, 2001 and, in certain circumstances, prior to that date. 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 $969 million at December 31, 2000 (1999 – $960 million).

NOTE 10

Preferred Shares

December 31	Number of Shares (thousands)	Dividend Rate Per Share	Redemption Price Per Share	2000 (millions of dollars)	1999 (millions of dollars)
Cumulative First Preferred Shares					
$2.80 Series	553	$ 2.80	$50.50	–	28
Series R	2,000	$ 2.975	$50.00	–	100
Series S	4,000	$ 2.575	$50.00-$51.00	–	200
Series U	4,000	$ 2.80	$50.00	**195**	195
Series Y	4,000	$ 2.80	$50.00	**194**	194
				389	717

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

On March 5, 1999, the Company issued 4,000,000 Series Y shares for net cash proceeds of $194 million. On June 1, 1999, the Company redeemed all of the outstanding Series O and Series P shares at a price of $52 per share and charged a premium on redemption of $11 million to retained earnings. On December 15, 1999, the Company redeemed all of the outstanding Series Q shares at a price of $50 per share.

On January 12, 2000, the Company redeemed all of the outstanding $2.80 Series shares at a price of $50.50 per share. On November 8, 2000, the Company acquired 97 per cent of the outstanding Series S shares, at a price of $50 per share, by way of a substantial issuer bid through the facilities of The Toronto Stock Exchange. On November 22, 2000, the Company purchased the remaining outstanding Series S shares, at a price of $50 per share, under the compulsory acquisition provisions of the Canada Business Corporations Act. On December 15, 2000, the Company redeemed all of the outstanding Series R shares at a price of $50 per share. 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 11

Common Shares

	Number of Shares (thousands)	Amount (millions of dollars)
Outstanding at January 1, 1998	455,849	4,147
Issued for cash or cash equivalent		
Under the dividend reinvestment and share purchase plan	4,960	131
Exercise of options	2,882	52
Other	17	1
Outstanding at December 31, 1998	463,708	4,331
Issued for cash or cash equivalent		
Under the dividend reinvestment and share purchase plan	10,254	195
Exercise of options	569	9
Outstanding at December 31, 1999	474,531	4,535
Issued for cash or cash equivalent		
Exercise of options	**382**	**5**
Outstanding at December 31, 2000	**474,913**	**4,540**

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

Net income per share is calculated by dividing net income applicable to common shares by the weighted average number of common shares outstanding. The weighted average number of shares, in millions, is 474.6, 469.5 and 460.0, respectively, for the years ended December 31, 2000, 1999 and 1998.

STOCK OPTIONS

	Number of Shares *(thousands)*	Weighted Average Exercise Prices	Options Exercisable *(thousands)*
Outstanding at January 1, 1998	12,283	$ 22.62	6,315
Adjustment of options from business combination[1]	(1,296)		
Granted	1,968	$ 29.71	
Exercised	(2,882)	$ 18.10	
Cancelled or expired	(145)	$ 24.22	
Outstanding at December 31, 1998	9,928	$ 19.97	7,400
Granted	3,988	$ 20.57	
Exercised	(569)	$ 15.16	
Cancelled or expired	(476)	$ 22.82	
Outstanding at December 31, 1999	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**

(1) As at July 2, 1998, the stock options previously granted by TransCanada and NOVA were exchanged and adjusted based on the principle that the accrued benefit inherent in such options would be preserved.

The following table summarizes information about stock options outstanding at December 31, 2000.

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Options *(thousands)*	Weighted Average Remaining Contractual Life *(years)*	Weighted Average Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Price
$10.03 to $19.86	8,309	7.5	$ 14.53	6,018	$ 15.96
$20.58 to $24.61	7,082	7.7	$ 22.62	6,084	$ 22.85
	15,391	7.6	$ 18.25	12,102	$ 19.43

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. At December 31, 2000, an additional 8 million common shares have been reserved for future issuance under KESIP.

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 1998 with certain amendments to conform the provisions to similar Canadian public corporation shareholder rights plans.

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, 2000, such terms did not restrict or alter the Company's ability to declare dividends.

NOTE 12

Price Risk Management and Financial Instruments

The Company issues short 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 prices and foreign currency exchange rates. The Company uses derivatives to manage the price or cash flow risk that results from these activities including activities conducted by the Company's discontinued operations. In 2000, the Company disposed of the majority of its discontinued operations. However, the Company will continue to manage the risk related to the activities of the remaining discontinued operations until disposition.

Carrying Values of Derivatives

The carrying amounts of derivatives, which hedge the price risk of the 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 by dealing with creditworthy counterparties in accordance with established credit approval practices. At December 31, 2000, for foreign currency and interest rate derivatives, total credit risk and the largest credit exposure to a single counterparty are $388 million and $232 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, 2000 and 1999, the Company had foreign currency denominated assets and liabilities which create 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 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) December 31 (millions of dollars)	**2000** Carrying Amount	**2000** Fair Value	1999 Carrying Amount	1999 Fair Value
Foreign Exchange Risk				
Cross-currency swaps				
U.S. dollars	**(18)**	**(18)**	(15)	(15)
Euros	**–**	**–**	38	38
Forward Foreign Exchange Contracts				
U.S. dollars	**(1)**	**(1)**	(10)	(10)
Euros	**–**	**–**	8	8

The principal amounts of cross-currency swaps are US$150 million (1999 – US$250 million) and € nil (1999 – €177 million). Principal amounts of forward foreign exchange contracts are US$35 million (1999 – US$380 million) and €28 million (1999 – €110 million).

RECONCILIATION OF FOREIGN EXCHANGE ADJUSTMENT

December 31 (millions of dollars)	**2000**	1999
Balance at beginning of year	**18**	15
Translation losses on foreign currency denominated net assets	**(1)**	(62)
Foreign exchange (losses)/gains on derivatives, net of income taxes	**(4)**	65
	13	18

ENERGY PRICE RISK MANAGEMENT

The Company adopted mark-to-market accounting for all of its energy trading contracts, effective December 31, 2000.

The Company's gas and power marketing operations offer integrated price risk management services to the energy sector. The Company executes energy trading contracts related to these commodities for overall management of its contractual portfolio. The Company's portfolio of energy trading contracts is primarily comprised of forward, futures, swap and option contracts for periods of up to 10 years, with fixed and floating price commitments. The net pre-tax unrealized loss on energy trading contracts included in revenues for 2000 was $87 million (1999 – $11 million).

The fair values of energy trading contracts as at December 31, 2000 and 1999 are shown in the table below.

December 31 (millions of dollars)	**2000**	1999
Assets		
Natural gas	**2,107**	216
Power	**748**	–
Liabilities		
Natural gas	**2,238**	223
Power	**711**	–

Notional volumes are 409 billion cubic feet (Bcf) (1999 – 366 Bcf) for natural gas futures contracts, 1,467 Bcf (1999 – 2,296 Bcf) for natural gas swaps, 1,972 Bcf (1999 – 434 Bcf) for natural gas options and 2,795 gigawatt hours (GWh) (1999 – nil) for power swaps. Volumes are 1,110 Bcf (1999 – 1,417 Bcf) for natural gas forward contracts and 105,800 GWh (1999 – nil) for power forward contracts.

U.S. DOLLAR TRANSACTION HEDGES

The Company purchases and sells energy commodities in U.S. dollars. To reduce risk and protect margins when purchase and sale contracts are denominated in different currencies, the Company enters into forward foreign exchange contracts and cross currency swaps which establish the foreign exchange rate for the cash flows from these purchase and sale transactions.

CANADIAN REGULATORY FOREIGN EXCHANGE AND INTEREST RATE MANAGEMENT ACTIVITY

The Company manages the foreign exchange risk of U.S. dollar debt of the Alberta System and 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. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms.

	2000		1999	
Asset/(Liability) December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Foreign Exchange Risk				
Cross-currency swaps	**65**	**65**	44	44
Interest Rate Risk				
Interest rate swaps				
Canadian dollars	**2**	**12**	8	(8)
U.S. dollars	**(1)**	**(3)**	(1)	(10)

The principal amounts of cross-currency swaps are US$425 million (1999 – US$425 million). Notional principal amounts for interest rate swaps are $780 million (1999 – $896 million) and US$125 million (1999 – US$200 million).

HEDGING ACTIVITIES OF JOINT VENTURES

Certain of the Company's joint ventures use interest rate derivatives to manage interest rate exposures. The Company's proportionate share of the credit exposure related to derivatives of the joint ventures is $26 million at December 31, 2000.

OTHER FAIR VALUES

	2000		1999	
December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Long-Term Debt				
Alberta System	**3,228**	**3,616**	3,488	3,675
Canadian Mainline	**5,823**	**6,445**	5,933	6,283
Other	**1,993**	**2,035**	3,191	2,967
Non-Recourse Debt of Joint Ventures	**1,325**	**1,349**	1,336	1,354
Junior Subordinated Debentures	**265**	**266**	253	228

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

NOTE 13

Income Taxes

The Company changed its method of accounting for income taxes effective January 1, 2000.

PROVISION FOR INCOME TAXES

Year ended December 31 (millions of dollars)	**2000**	1999	1998
Current			
Canada	**177**	172	214
Foreign	**32**	114	27
	209	286	241
Future			
Canada	**16**	(104)	(77)
Foreign	**33**	(9)	15
	49	(113)	(62)
	258	173	179

GEOGRAPHIC COMPONENTS OF INCOME

Year ended December 31 (millions of dollars)	**2000**	1999	1998
Canada	**657**	451	474
Foreign	**191**	264	168
Income from continuing operations before income taxes	**848**	715	642

RECONCILIATION OF INCOME TAX EXPENSE

Year ended December 31 (millions of dollars)	**2000**	1999	1998
Income from continuing operations before income taxes	**848**	715	642
Income from regulated operations not subject to tax currently	**(245)**	(336)	(353)
	603	379	289
Federal and provincial statutory tax rate	**44.6%**	44.6%	44.6%
Expected income tax expense	**269**	169	129
Non-deductible expenses	**3**	15	26
Net difference between the federal and provincial statutory tax rate and rate of foreign authorities	**(7)**	(33)	(20)
Large corporations tax	**32**	32	33
Change in valuation allowance	**(8)**	–	–
Adjustment to future tax assets and liabilities for enacted changes in tax laws and rates	**(28)**	–	–
Other	**(3)**	(10)	11
Actual income tax expense	**258**	173	179

FUTURE INCOME TAX ASSETS AND LIABILITIES

December 31, 2000 (millions of dollars)

Net operating and capital loss carryforwards	**276**
Deferred costs	**100**
Deferred revenue	**56**
Alternative minimum tax credits	**40**
Other	**47**
	519
Less: Valuation allowance	**25**
Future income tax assets, net of valuation allowance	**494**
Accelerated tax depreciation on plant and equipment	**239**
Investments in subsidiaries and partnerships	**49**
Other	**14**
Future income tax liabilities	**302**
Net future income tax assets	**192**

At the direction of the EUB and the NEB, the Company follows the taxes payable method of accounting for income taxes related to the operations of the Canadian natural gas transmission operations. Had the liability method of accounting been prescribed by these regulatory bodies, additional future income tax liabilities in the amount of $1,722 million at December 31, 2000 would have been recorded and recovered in tolls.

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 $41 million at December 31, 2000 (1999 – $33 million; 1998 – $60 million).

INCOME TAX PAYMENTS

Income tax payments of $257 million, $196 million and $332 million were made during the years ended December 31, 2000, 1999, and 1998, respectively.

NOTE 14

Notes Payable

	2000		1999	
	Outstanding December 31 *(millions of dollars)*	**Weighted Average Interest Rate Per Annum at December 31**	Outstanding December 31 *(millions of dollars)*	Weighted Average Interest Rate Per Annum at December 31
Commercial Paper				
Canadian dollars	**35**	**5.9%**	138	4.9%
U.S. dollars	**114**	**6.0%**	14	5.0%
Notes Payable of Joint Ventures				
Canadian dollars	**51**	**6.4%**	60	6.5%
U.S. dollars	**–**	**–**	2	6.8%
	200		214	

The Company has unused lines of credit of $2.1 billion at December 31, 2000, which support the Company's commercial paper program and are available to secure energy commodity purchases and for general corporate purposes. 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 $2 million for the year ended December 31, 2000 (1999 – $3 million).

NOTE 15

Employee Future Benefits

The Company changed its method of accounting for employee future benefits effective January 1, 2000.

The Company sponsors defined benefit and defined contribution pension plans that cover substantially all employees. 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 are based on the participating employees' pensionable earnings. 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.

The total expense for the Company's defined contribution plan is $8 million for the year ended December 31, 2000.

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

Year ended December 31, 2000 (millions of dollars)	Pension Benefit Plans	Other Benefits Plan
Change in Benefit Obligation		
Benefit obligation – beginning of year	626	48
Current service cost	15	2
Interest cost	44	3
Employees' contributions	1	–
Benefits paid	(55)	(3)
Actuarial loss	52	6
Transfers to defined contribution plan	(35)	–
Corporate restructuring giving rise to curtailments	(4)	(1)
Benefit obligation – end of year	644	55
Change in Plan Assets		
Plan assets at fair value – beginning of year	652	–
Actual return on plan assets	34	–
Employer contributions	23	3
Employee contributions	1	–
Benefits paid	(55)	(3)
Transfer to defined contribution plan	(43)	–
Plan assets at fair value – end of year	612	–
Funded status – plan deficit	(32)	(55)
Unamortized net actuarial loss	65	6
Unrecorded transitional obligation related to regulated business	–	31
Accrued benefit asset (liability), net of valuation allowance of nil	33	(18)

December 31, 1999 (millions of dollars)	
Assets available at average market value	644
Actuarial present value of accumulated benefit obligations	574
Surplus on an accounting basis	70

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

December 31, 2000	Pension Benefit Plans	Other Benefits Plan
Discount rate	**6.80%**	**6.90%**
Expected long-term rate of return on plan assets	**7.24%**	**–**
Rate of compensation increase	**3.50%**	**3.50%**

For measurement purposes, an 8.8 per cent annual rate of increase in the per capita cost of covered health care benefits was assumed for 2001. The rate was assumed to decrease gradually to 4.0 per cent for 2005 and remain at that level thereafter.

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

Year ended December 31, 2000 (millions of dollars)	Pension Benefit Plans	Other Benefits Plan(1)
Current service cost	**15**	**2**
Interest cost	**44**	**3**
Expected return on plan assets	**(45)**	**–**
Amortization of unrecorded transitional obligation related to regulated business	**–**	**2**
Corporate restructuring giving rise to curtailments	**(5)**	**–**
	9	**7**
Net benefit plan expense – discontinued operations	**(1)**	**–**
Net benefit plan expense – continuing operations	**8**	**7**

PENSION EXPENSE(2)

Year ended December 31 (millions of dollars)	1999	1998
Continuing operations	12	14
Discontinued operations	2	5
	14	19

(1) Employee termination benefits related to restructuring are included in restructuring and other costs (see Note 18).

(2) Pension expense for the years ended December 31, 1999 and 1998 includes the expense related to both the Company's defined benefit and defined contribution pension plans. Prior to January 1, 2000, the cost of post-employment benefits other than pensions was expensed when paid.

NOTE 16

Operating Working Capital

Year ended December 31 (millions of dollars)	2000	1999	1998
(Increase)/decrease in accounts receivable	**(888)**	76	(48)
Decrease/(increase) in inventories	**47**	(104)	(22)
(Increase)/decrease in other current assets	**(6)**	9	2
Increase in accounts payable	**1,058**	143	215
(Decrease)/increase in accrued interest	**(5)**	9	43
	206	133	190

NOTE 17

Commitments and Contingencies

The Company and its subsidiaries are subject to various legal proceedings and actions arising in the normal course of business. Management considers the aggregate liability, if any, to the Company and its subsidiaries in respect of these actions and proceedings not to be material.

NOTE 18

Restructuring and Other Costs

Year ended December 31 (millions of dollars)	**2000**	1999	1998
Restructuring			
Employee terminations	**5**	51	28
Real estate	**–**	17	34
	5	68	62
Provision for additional Merger Plan terminations	**–**	47	–
	5	115	62
Other			
Asset impairments	**–**	13	109
Costs to exit a business and other	**(5)**	42	36
	(5)	55	145
	–	170	207

In 1999, TransCanada recorded restructuring and other costs of $170 million including $123 million as a result of the Company's strategy (1999 Strategic Plan) of pursuing a more focused set of growth opportunities from its core businesses and achieving greater cost efficiencies.

In 1998, the Company recorded restructuring and other costs totalling $207 million related to the business combination with NOVA Corporation (Merger Plan).

(number of employees)	1999 Strategic Plan	Merger Plan	Total
Original terminations	367	600	967
Additional Merger Plan terminations	–	364	364
	367	964	1,331
Terminations completed			
1998	–	(274)	(274)
1999	(65)	(608)	(673)
2000	**(124)**	**(82)**	**(206)**
Remaining terminations to occur in 2001	178	–	178

RESTRUCTURING COSTS

The 1999 Strategic Plan includes costs of $51 million for the termination of 367 employees, represented by 61 management and 306 non-management positions. The Company also recorded $47 million, net of regulatory recoveries, in 1999 related to the additional Merger Plan employee terminations.

In 1999, other restructuring costs of $17 million (1998 – $34 million) were recorded related to certain real estate costs, including vacant office space resulting from employee reductions.

REMAINING RESTRUCTURING LIABILITY

	1999 Strategic Plan	Merger Plan	Total
December 31, 2000 (millions of dollars)			
Employee terminations	**35**	**26**	**61**
Real estate	**12**	**2**	**14**
	47	**28**	**75**
December 31, 1999 (millions of dollars)			
Employee terminations	47	56	103
Real estate	12	5	17
	59	61	120

Restructuring costs related to the 1999 Strategic Plan of $12 million were paid in the year ended December 31, 2000 (1999 – $4 million). Restructuring costs related to the Merger Plan of $38 million, net of regulatory recoveries, were paid in the year ended December 31, 2000 (1999 – $29 million; 1998 – $10 million).

The restructuring provisions were determined based on estimates prepared at the time the plans were approved by Management and the Board of Directors. The remaining accruals are considered adequate to cover committed restructuring actions.

OTHER COSTS

The Company recorded $13 million in 1999 (1998 – $109 million) for asset impairments. The amount of asset impairments was determined by comparing the net carrying value of assets to the undiscounted future cash flows of the related assets and market appraisals. Other included costs related to the restructuring of the Netback Pool and the exit costs related to the sale of a gas marketing subsidiary.

NOTE 19

Discontinued Operations

In April 1999, the Board of Directors approved a plan (April Plan) to dispose of ANGUS Chemical Company, a specialty chemicals business that manufactured and marketed nitroparaffins and their derivatives; TransCanada's U.S. midstream business, which had ownership interests in and operated plants that separate natural gas liquids from natural gas; and the U.S. refined products and natural gas liquids marketing business. The Company recorded a net gain of $20 million, after tax, in 1999, related to these discontinued operations. The Company substantially completed the disposals under the April Plan in 1999.

In December 1999, the Board of Directors approved a plan (December Plan) to dispose of the Company's International business, its investment in the Express Pipeline System, the Canadian midstream business, Cancarb Limited and the petroleum and products marketing business. The International business included investments in energy-related projects outside of Canada and the United States. The Express Pipeline System transported and marketed crude oil from Alberta to the United States. The Canadian midstream business included various interests in gathering and processing plants, natural gas liquids extraction plants and a fractionator plant in western Canada. Cancarb Limited manufactured thermal carbon black. The petroleum and products marketing business purchased and sold crude oil, refined products and natural gas liquids under short-term contracts with producers, customers and marketers in Canada and the United States.

The Company recorded a net loss of $439 million, after tax, in 1999, related to the December Plan reflecting Management's best estimates. The disposal plan has been substantially completed in 2000 and as a result of actual results and revised estimates a positive $200 million after-tax adjustment was recorded. This adjustment is primarily due to proceeds in excess of the Company's original estimate. Further adjustments to the estimate of the net loss on disposal will be recognized as a gain or loss on discontinued operations in the period such changes are determined.

Realized net income related to discontinued operations was $70 million in 2000 compared to the original estimate of $54 million. Realized proceeds from disposals of discontinued operations were $2.1 billion in 2000, compared to the original estimate of $1.9 billion. In January 2001, additional proceeds of US$435 million were received upon closing of one of the sales compared to originally estimated proceeds of US$358 million.

REVENUES AND NET INCOME/(LOSS) FROM DISCONTINUED OPERATIONS

Year ended December 31 (millions of dollars)	**2000**	1999	1998
Revenues from Discontinued Operations			
April Plan	**119**	2,786	2,911
December Plan	**2,867**	3,721	3,346
	2,986	6,507	6,257
Net Income/(Loss) from Discontinued Operations[1]			
April Plan	–	(7)	(35)
December Plan	–	40	26
Asset impairments[2]	–	(285)	(91)
	–	(252)	(100)
Income taxes	–	147	63
Results of operations prior to plan approval	–	(105)	(37)
Net Gain/(Loss) from Discontinued Operations			
April Plan[1]	–	(19)	–
Income taxes	–	39	–
	–	20	–
December Plan[1]	**295**	(442)	–
Income taxes	**(95)**	3	–
	200	(439)	–
Split off of commodity chemicals business	–	–	6
	200	(524)	(31)

(1) The net loss on disposal in 1999 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 gain in 2000 represents an adjustment to the 1999 provision resulting from transactions completed and revisions to estimates.

(2) Amounts reflect the impairment of certain of the Company's midstream assets. Asset impairments were determined by comparing estimated future undiscounted net cash flows with the net carrying value of the related asset.

As at December 31, 2000, remaining discontinued businesses are primarily certain of the Company's International investments. Management continues its efforts to dispose of these remaining assets.

OTHER FINANCIAL INFORMATION

December 31 (millions of dollars)	**2000**	1999
Current assets	**154**	873
Long-term investments	**731**	1,274
Plant, property and equipment	**372**	2,027
Other non-current assets	**80**	230
	1,337	4,404
Current liabilities	**98**	579
Long-term and non-recourse debt	**213**	662
Other non-current liabilities	**75**	126
	386	1,367
Net assets of discontinued operations	**951**	3,037

PROVISION FOR LOSS ON DISCONTINUED OPERATIONS

(millions of dollars)	
Balance at January 1, 2000	**464**
Adjustment to original provision	**(200)**
Results and net loss on sales of discontinued operations in 2000	**(98)**
Impact of tax law and income tax rate changes	**(38)**
Balance at December 31, 2000	**128**

NOTE 20

Business Combination with NOVA

Effective July 2, 1998, TransCanada entered into a business combination with NOVA Corporation (NOVA). NOVA's businesses included gathering, processing, transmission and marketing of natural gas and natural gas liquids, and production and marketing of commodity chemicals. Under the terms of a Plan of Arrangement (the Arrangement), the companies merged and then split off the commodity chemicals business carried on by NOVA into a separate public company. The nature of the business combination was such that neither of the combining companies could be identified as the acquirer. The business combination was accounted for using the pooling of interests method. Third party fees, costs and expenses related to the business combination totalled approximately $182 million after income taxes. The transaction costs were charged to retained earnings in 1998.

The commodity chemicals business, which was split off on July 2, 1998 under the terms of the Arrangement, has been accounted for as discontinued operations. The split off was accounted for by removing the book values of the assets and liabilities of the commodity chemicals business from the Company's consolidated financial statements as at July 2, 1998. In 1998, consolidated retained earnings and the foreign exchange adjustment were reduced by $1,708 million and $51 million, respectively.

NOTE 21

Significant Differences Between Canadian and U.S. GAAP

NET INCOME RECONCILIATION

Year ended December 31 (millions of dollars except per share amounts)	**2000**	1999	1998
Net income from continuing operations as reported in accordance with Canadian GAAP	**590**	542	463
U.S. GAAP adjustments			
Preferred securities charges[1]	**(78)**	(82)	(40)
Tax impact of preferred securities charges	**34**	36	19
Income taxes[2]	**–**	(15)	–
Tax recoveries from substantively enacted tax rates[3]	**(28)**	–	–
Gain on early retirement of long-term debt[4]	**(15)**	–	–
Tax impact on gain on early retirement of long-term debt	**2**	–	–
Transaction costs of business combination[5]	**–**	–	(182)
Income from continuing operations in accordance with U.S. GAAP	**505**	481	260
Net income/(loss) from discontinued operations in accordance with U.S. GAAP[6]	**200**	(476)	(143)
Income before extraordinary item in accordance with U.S. GAAP	**705**	5	117
Extraordinary item:			
Gain on early retirement of long-term debt, net of tax	**13**	–	–
Net income in accordance with U.S. GAAP	**718**	5	117
Basic and diluted net income/(loss) per share in accordance with U.S. GAAP			
Continuing operations	**$ 0.99**	$ 0.91	$ 0.45
Discontinued operations	**0.42**	(1.01)	(0.31)
Extraordinary item	**0.03**	–	–
	$ 1.44	$ (0.10)	$ 0.14

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

(2) Under U.S. GAAP, the liability method is used to calculate deferred income taxes and deferred income tax expense is calculated as the net change in the deferred tax asset or liability in the year. Prior to 2000, the deferral method was used under Canadian GAAP.

(3) 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 and accordingly the related tax recoveries are not recognized.

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

(5) Under U.S. GAAP, the transaction costs related to the business combination with NOVA are recognized as an expense, rather than a charge to retained earnings.

(6) Net income/(loss) from discontinued operations reconciliation

Year ended December 31 (millions of dollars)	**2000**	1999	1998
Net income/(loss) from discontinued operations in accordance with Canadian GAAP			
U.S. GAAP adjustments	**200**	(524)	(31)
Asset impairments [a]	**–**	(97)	(50)
Provision for loss on disposal [b]	**–**	147	–
Income taxes	**–**	(2)	(11)
Commodity chemicals business [c]	**–**	–	(51)
Net income/(loss) from discontinued operations in accordance with U.S. GAAP	**200**	(476)	(143)

(a) Under U.S. GAAP, the amount of an impairment is determined by comparing the net carrying value of an asset to its discounted future net cash flows. Under Canadian GAAP, the net carrying amount is compared to undiscounted future net cash flows.

(b) Under U.S. GAAP, the provision for loss on disposal is reduced by an amount equal to the difference in asset carrying values measured under Canadian and U.S. GAAP.

(c) The differences relate primarily to foreign exchange losses in the commodity chemicals business of NOVA which was split off effective July 2, 1998.

CONDENSED STATEMENT OF INCOME(7)

Year ended December 31 (millions of dollars)	**2000**	1999	1998
Revenues	**20,799**	11,475	10,478
Cost of sales	**17,317**	7,890	7,002
Other costs and expenses	**1,417**	1,517	1,504
Depreciation	**610**	552	498
Restructuring and other costs	**–**	170	207
Transaction costs of business combination	**–**	–	182
	19,344	10,129	9,393
Operating income	**1,455**	1,346	1,085
Other (income)/expenses			
Equity income	**(236)**	(240)	(234)
Other expenses	**936**	961	906
Income taxes	**250**	144	153
	950	865	825
Income from continuing operations in accordance with U.S. GAAP	**505**	481	260
Net income/(loss) from discontinued operations in accordance with U.S. GAAP	**200**	(476)	(143)
Income before extraordinary item in accordance with U.S. GAAP	**705**	5	117
Extraordinary item:			
Gain on early retirement of long-term debt, net of tax	**13**	–	–
Net income in accordance with U.S. GAAP	**718**	5	117

COMPREHENSIVE INCOME IN ACCORDANCE WITH U.S. GAAP

Year ended December 31 (millions of dollars)	**2000**	1999	1998
Net income in accordance with U.S. GAAP	**718**	5	117
Adjustments affecting comprehensive income under U.S. GAAP			
Foreign currency translation adjustment	**(5)**	3	(18)
Adjustments related to the business combination with NOVA	**–**	–	(51)
Comprehensive income in accordance with U.S. GAAP	**713**	8	48

CONDENSED BALANCE SHEET(7)

December 31 (millions of dollars)	**2000**	1999
Current assets	**5,081**	1,900
Current assets of discontinued operations	**153**	795
Unrealized gains on energy trading contracts	**521**	63
Long-term investments	**1,284**	1,796
Plant, property and equipment	**15,212**	15,034
Regulatory asset(8)	**3,670**	3,508
Other assets	**455**	202
Long-term assets of discontinued operations	**805**	2,926
	27,181	26,224
Current liabilities	**5,885**	2,663
Provision for loss on discontinued operations	**76**	376
Current liabilities of discontinued operations	**94**	475
Unrealized losses on energy trading contracts	**608**	66
Deferred amounts	**344**	379
Long-term debt	**9,928**	11,588
Deferred income taxes(8)	**3,409**	3,305
Preferred securities(9)	**994**	983
Trust originated preferred securities	**218**	218
Long-term liabilities of discontinued operations	**72**	314
Non-controlling interests	**2**	243
Shareholders' equity	**5,551**	5,614
	27,181	26,224

(7) In accordance with U.S. GAAP, the condensed Statement of 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.

(8) 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.

(9) Under U.S. GAAP, the Preferred Securities are classified as a liability. The fair value of the Preferred Securities at December 31, 2000 is $974 million (1999 – $828 million).

INCOME TAXES

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

December 31 (millions of dollars)	**2000**	1999
Deferred Tax Liabilities		
Accelerated tax depreciation on plant and equipment	**2,027**	1,910
Taxes on future revenue requirement	**1,610**	1,524
Undistributed earnings of subsidiaries and joint ventures	**250**	114
Other	**38**	24
	3,925	3,572
Deferred Tax Assets		
Net operating and capital loss carryforwards	**292**	186
Deferred amounts	**155**	77
Other	**94**	20
	541	283
Less: Valuation allowance	**25**	16
	516	267
Net deferred tax liabilities	**3,409**	3,305

STOCK BASED COMPENSATION

The Company uses the measurement rules of APB Opinion No. 25 to account for employee stock options. The use of the fair value method of Statement of Financial Accounting Standards No. 123 "Accounting for Stock-Based Compensation", would have resulted in net income/(loss) of $714 million in 2000 (1999 – $(13) million; 1998 – $109 million) and net income/(loss) per share of $1.43 in 2000 (1999 – $(0.14); 1998 – $0.13).

OTHER

The Financial Accounting Standards Board issued a new standard, Statement of Financial Accounting Standards No. 133 (SFAS 133) "Accounting for Derivative Instruments and Hedging Activities", which for the Company will be effective January 1, 2001. The impact of SFAS 133 on financial statements prepared under U.S. GAAP is not expected to be significant.

SUPPLEMENTARY INFORMATION

Selected Quarterly Consolidated Financial Data

The following sets forth selected quarterly financial data for the four quarters of 2000 and 1999 in millions of dollars except for per share amounts.

Three months ended (unaudited)	March 31	June 30	September 30	December 31
2000				
Revenues	**3,618**	**4,295**	**5,050**	**8,193**
Net income applicable to common shares from continuing operations before unusual items	**155**	**132**	**156**	**162**
Net income per share from continuing operations before unusual items	**$0.33**	**$0.28**	**$0.33**	**$0.34**
1999				
Revenues	2,567	2,666	3,124	3,499
Net income applicable to common shares from continuing operations before unusual items	139	130	133	103
Net income per share from continuing operations before unusual items	$0.30	$0.28	$0.28	$0.22

Consolidated Ratio of Earnings to Fixed Charges

The following table sets forth the company's consolidated ratio of earnings to fixed charges for the periods indicated.

Year ended December 31	**2000**	1999	1998	1997	1996
Ratio of earnings to fixed charges(1)	**1.8**	1.6	1.6	1.8	1.9

(1) 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 following table sets forth the company's consolidated ratio of earnings to fixed charges for the periods indicated, determined in the manner described in (1) above, but utilizing similar information determined in accordance with U.S. GAAP.

Year ended December 31	**2000**	1999	1998	1997	1996
Ratio of earnings to fixed charges	**1.7**	1.5	1.3	1.8	1.9

Differences are described in Note 21 "Significant Differences Between Canadian and U.S. GAAP", to the Consolidated Financial Statements.

FIVE-YEAR FINANCIAL HIGHLIGHTS

(millions of dollars except where indicated)	**2000**	1999	1998	1997	1996
Operating Results					
Revenues	**21,156**	11,856	10,960	9,880	8,197
Net income/(loss)					
Continuing operations before unusual items	**684**	603	629	648	597
Continuing operations after unusual items	**590**	542	463	550	597
Discontinued operations	**200**	(524)	(31)	198	259
Assets					
Plant, property and equipment					
Alberta System	**5,180**	5,283	5,210	4,997	4,795
Canadian Mainline	**9,202**	9,386	9,053	8,058	7,233
North American pipelines and other transmission	**2,418**	2,485	3,228	2,518	2,407
Other	**873**	584	561	462	430
Total assets					
Continuing operations	**24,211**	20,565	20,217	18,162	16,590
Discontinued operations	**1,337**	4,404	5,115	5,132	4,237
Capitalization					
Long-term debt	**9,928**	11,591	11,333	9,083	7,883
Non-recourse debt of joint ventures	**1,296**	1,272	1,666	1,203	1,200
Junior subordinated debentures	**243**	241	239	224	223
Preferred securities	**969**	960	978	280	261
Preferred shares	**389**	717	908	713	513
Common shareholders' equity	**5,230**	4,935	5,349	7,285	7,094
Cash Flow Data					
Funds generated from continuing operations	**1,226**	1,033	1,100	1,229	973
Capital expenditures					
Continuing operations	**518**	1,323	2,445	1,648	958
Discontinued operations	**294**	501	1,208	1,108	1,122
Share Statistics					
Net income/(loss) per share					
Continuing operations before unusual items	**$ 1.28**	$ 1.08	$ 1.21	$ 1.30	$ 1.22
Continuing operations after unusual items	**$ 1.08**	$ 0.95	$ 0.85	$ 1.08	$ 1.22
Discontinued operations	**$ 0.42**	$ (1.12)	$ (0.07)	$ 0.43	$ 0.57
Funds generated from continuing operations per share	**$ 2.58**	$ 2.20	$ 2.39	$ 2.69	$ 2.14
Registered Common Shareholders, December 31	**30,758**	32,328	33,346	N/A	N/A
U.S. GAAP Information					
Net income/(loss)					
Continuing operations before unusual and extraordinary items	**599**	542	608	640	589
Continuing operations before extraordinary item	**505**	481	260	542	589
Discontinued operations	**200**	(476)	(143)	53	251
Extraordinary item	**13**	–	–	–	–
Net income/(loss) per share					
Continuing operations before unusual and extraordinary items	**$ 1.19**	$ 1.04	$ 1.21	$ 1.30	$ 1.21
Continuing operations before extraordinary item	**$ 0.99**	$ 0.91	$ 0.45	$ 1.09	$ 1.21
Discontinued operations	**$ 0.42**	$ (1.01)	$ (0.31)	$ 0.11	$ 0.55
Extraordinary item	**$ 0.03**	–	–	–	–
Common shareholders' equity	**5,162**	4,897	5,277	7,100	7,068

INVESTOR INFORMATION

Stock Exchanges and Symbols

Common shares are listed on the New York and Toronto 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
- 8.50% Canadian Originated Preferred Securities[SM] (COPrS[SM]): TRP.Pr.C
- 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.

Important Dates

Scheduled common share dividend payment dates in 2001 are January 31, April 30, July 31 and October 31.

Dividend Reinvestment and Share Purchase Plan

TransCanada's dividend reinvestment and share purchase plan allows common and preferred shareholders to purchase additional common shares by reinvesting their cash dividend without incurring brokerage or administrative fees. Participants in the plan may make optional cash payments to buy additional shares of up to $10,000 (US$7,000) per quarter. Optional cash payments must be received by our Plan Agent, Computershare Trust Company of Canada on or prior to the common share record dates which are scheduled in 2001 to be March 30, June 29, September 28 and December 31.

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, changes to the U.S. Internal Revenue Service (IRS) regulations require 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.

Common Shares

Transfer agents and Registrars: Computershare Trust Company of Canada (Montréal, Toronto, Winnipeg, Calgary and Vancouver) and Computershare Trust Company (New York).

[*SM]Service marks of Merrill Lynch & Co., Inc.

Preferred Shares

Transfer agent and Registrar for the preferred shares listed below: Computershare Trust Company of Canada (Montréal, Toronto, Winnipeg, Calgary and Vancouver).

- Cumulative redeemable first preferred shares, Series U, and Series Y

Preferred Securities

Trustee for the preferred securities listed below: The Bank of New York (New York).

- 8.75% TOPrS SM*
  (TOPrS are obligations of TransCanada Capital, an unaffiliated business trust.)
- 8.50% COPrS SM
- 8.25% Preferred Securities

First Mortgage Pipe Line Bonds

Trustee and Registrar: 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).

TransCanada Debentures

Trustee and Registrar for Canadian series listed below: CIBC Mellon Trust Company (Halifax, Montréal, Toronto, Winnipeg, Regina, Calgary and Vancouver).

10.80% series L	11.90% series S
11.10% series N	11.80% series U
10.50% series O	9.80% series V
10.50% series P	9.45% series W
10.625% series Q	8.40% series A
11.85% series R	

Trustee and Registrar for U.S. series 9.875%, 8.625% and 8.50%: Bank of New York (New York).

* SM Service marks of Merrill Lynch & Co., Inc.

NGTL Debentures

Trustee and Registrar for Canadian series listed below: CIBC Mellon Trust Company (Halifax, Montréal, Toronto, Winnipeg, Regina, Calgary and Vancouver).

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

Trustee and Registrar for U.S. Debentures series 8.50% and 7.875%; and for U.S. Notes series 7.875% and 8.50%: U.S. Bank Trust National Association.

Subordinated Debentures

Trustee and Registrar for U.S. series 9.125%: The Bank of Nova Scotia Trust Company of New York.

TransCanada Canadian Medium Term Notes and NGTL Canadian Medium Term Notes

Trustee: CIBC Mellon Trust Company (Halifax, Montréal, Toronto, Winnipeg, Regina, Calgary and Vancouver).

TransCanada U.S. Medium Term Notes

Trustee: Bank of New York (New York) (unsubordinated notes).

NGTL U.S. Medium Term Notes

Trustee: U.S. Bank Trust National Association.

Please refer to TransCanada's Notice of 2001 Annual and Special Meeting of Common Shareholders and Notice of 2001 Special Meeting of First Preferred Shareholders and Management Proxy Circular for the Company's report on Corporate Governance.

TRP PERFORMANCE

COMMON SHARE PRICE RANGE

Toronto Stock Exchange	**High**	**Low**
First Quarter 2000	**$ 13.00**	**$ 9.80**
Second Quarter 2000	**$ 12.20**	**$ 10.10**
Third Quarter 2000	**$ 14.65**	**$ 11.20**
Fourth Quarter 2000	**$ 17.25**	**$ 13.10**
New York Stock Exchange *(US dollars)*		
First Quarter 2000	**$ 8.88**	**$ 6.81**
Second Quarter 2000	**$ 8.13**	**$ 6.75**
Third Quarter 2000	**$ 9.94**	**$ 7.56**
Fourth Quarter 2000	**$ 11.50**	**$ 8.69**

ADDITIONAL INFORMATION

To access TransCanada's corporate and financial information, including quarterly reports and news releases, visit our Internet site at **www.transcanada.com**

Annual Information Form

TransCanada's 2000 Annual Information Form, as filed with Canadian securities commissions and as filed under Form 40-F with the U.S. Securities and Exchange Commission, may be obtained from:

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

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

Updates

If you would like to receive quarterly reports but are not a registered shareholder, please write, call or email Computershare Trust Company of Canada with your name and address.

You can also change your address, eliminate multiple mailings, request information regarding cheques, share certificates, stock transfers or dividend reinvestment plan account updates, by contacting our transfer agent:

Computershare Trust Company of Canada
Equity Transfer Services
600, 530 – 8th Avenue S.W.
Calgary, Alberta, Canada T2P 3S8
Telephone: (403) 267-6555 or toll-free: 1-888-267-6555
Email enquiries can be sent to careregistry@computershare.com

Metric Conversion Table

The conversion factors set out below provide only approximate conversions. To convert from Metric to Imperial, multiply by the factor indicated. To convert from Imperial to Metric, divide by the factor indicated.

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.

Board of Directors

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Calgary, Alberta

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R. B. Coleman Consulting Co. Ltd.
Calgary, Alberta

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Greenwood Village, Colorado

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Chairman
PCL Construction Group Inc.
Edmonton, Alberta

*Not standing for re-election.

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Albrecht W.A. Bellstedt, *Q.C.*
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Law and General Counsel

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

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Walentin (Val) Mirosh
Executive Vice-President
Regulatory Strategy and Northern Development

Sarah E. Raiss
Executive Vice-President
Human Resources and Public Sector Relations

Ronald J. Turner
Executive Vice-President
Operations and Engineering

Annual Meeting

The annual and special meeting of shareholders is scheduled for April 27, 2001 at 10:30 a.m. at the RoundUp Centre, Calgary, Alberta.

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Better: We know and understand our skill set and talents, and we've identified those we need to continue to succeed. Our expertise is in pipeline and power operations, financial management, natural gas and power marketing and trading, deal structuring and constructing large capital pipeline and power projects. We're improving our abilities and strengths in managing organizational processes to be more effective and efficient in everything we do and to be customer and market focused in identifying what it is we need to do—*we're getting better.*

Faster: We enjoy an enviable talent pool of expertise and experience within TransCanada and while we've implemented measures in the last year to reduce the numbers and layers of management that previously existed—starting with our executive team—we're mindful that we need to attract and retain the right mix of talents to deliver on TransCanada's plans. We will continue to develop the leadership abilities of our management teams to operate strategically, proactively and responsively in an increasingly competitive environment—*we're getting faster.*

Cheaper: We need to improve our ability to provide best value for best price. Cost of service is critical to our customers. We understand that. We're identifying areas where we can become more cost efficient—cheaper—but cheaper where it makes sense in order for us to provide customers with best total cost for the best products and solutions they expect to meet their needs. It's being effective and efficient. *Effective*—doing the right things. *Efficient*—doing things right.

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TransCanada welcomes questions from shareholders and potential investors.

Please telephone
David Moneta
Director, Investor Relations
at 1-800-361-6522
(Canada and U.S. Mainland)

Visit TransCanada's Internet site at:
www.TransCanada.com

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