ANNUAL REPORT 2001

# THE POWER *of* ENERGY

TransCanada

*In business to deliver* ™

**Energy.** It's not just our business, it's how we do business. Fifty years ago, TransCanada pioneered the development of the first cross-Canada pipeline to transport western gas to eastern markets. Today, our 38,000 kilometre (24,000 mile) natural gas pipeline system is one of the largest and most sophisticated pipeline systems in the world. In the early 1990s, we entered the power business. Over the past five years, we've grown our power assets from two plants generating approximately 260 megawatts (MW) to 16 plants with more than 2,250 MW – enough power to meet the needs of more than 2.2 million households.

**Power.** From our financial strength to the skills and expertise of our people, we have the power to perform in an increasingly competitive environment. Our core businesses of natural gas transmission and power drive our growth. We're focused on seizing new opportunities – offering flexible and competitive solutions to enable our customers to capitalize on new sources of natural gas – taking bold, proactive steps to meet the increasing energy needs of markets across the northern tier of North America.

We see our future in connecting existing and new gas supplies with rapidly growing markets in the northern tier of North America … in generating efficient sources of power to meet growing market needs … in developing supply and market opportunities with our physical and intellectual assets … and in having and retaining talented employees to work together to make all of this happen.

## OVER THE NEXT FIVE YEARS, TRANSCANADA WILL …

- foster the development of a Canadian regulatory framework that enhances profitability and competitiveness and supports new and flexible service choices for our customers;
- capitalize on increasing demand for natural gas and play a key role in bringing northern gas to market;
- become a significant player in power generation;
- draw inspiration from the energy of a winning team, passionate about customer and shareholder satisfaction and the success of our company;
- develop into a role model of operational excellence.

**… STRIVE TO DELIVER SUPERIOR TOTAL SHAREHOLDER RETURNS.**

## TABLE OF CONTENTS

*2001 Annual Report*

## FINANCIAL HIGHLIGHTS

**In 2001, TransCanada delivered on its commitment to provide solid, stable returns to shareholders, underpinned by profitable investments in our core businesses. Through the disciplined execution of our strategy to divest non-core assets, pay down debt and continually reduce operating costs, we further strengthened our balance sheet and increased discretionary cash flow.**

**As a result of our efforts, total shareholder return in 2001 was 21 per cent. In January 2002, the Board of Directors increased the quarterly dividend by 11 per cent, reflecting continued, sustainable growth in cash flow and earnings from continuing operations and significant improvements in their quality and predictability.**

### OPERATING RESULTS

**December 31** (millions of dollars)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| **Income Statement** | | | |
| Net income applicable to common shares from continuing operations | 670 | 650 | 454 |
| Net income/(loss) applicable to common shares | 603 | 711 | (80) |
| EBITDA* from continuing operations | 3,005 | 2,901 | 2,555 |
| **Cash Flow** | | | |
| Funds generated from continuing operations | 1,514 | 1,283 | 1,041 |
| Capital expenditures in continuing operations | 440 | 518 | 1,323 |
| **Balance Sheet** | | | |
| Long-term debt | 9,347 | 9,928 | 11,591 |
| Common shareholders' equity | 5,429 | 5,230 | 4,935 |

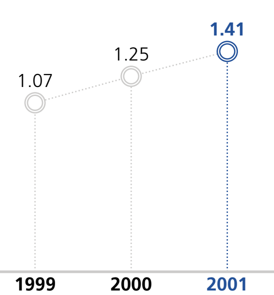
*Earnings before interest expense, income taxes, depreciation and amortization.

### COMMON SHARE STATISTICS

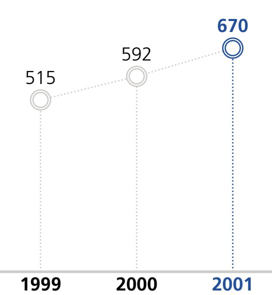
**Year ended December 31**

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| Net income per share from continuing operations | $ 1.41 | $ 1.37 | $ 0.94 |
| Net (loss)/income per share from discontinued operations | $ (0.14) | $ 0.13 | $ (1.13) |
| Net income/(loss) per share – Basic and Diluted | $ 1.27 | $ 1.50 | $ (0.19) |
| Funds generated per share from continuing operations | $ 3.18 | $ 2.70 | $ 2.22 |
| Common shares outstanding (millions) | | | |
| Average for the period | 475.8 | 474.6 | 469.5 |
| End of period | 476.6 | 474.9 | 474.5 |

**Net Earnings Per Share from Continuing Operations before Unusual Items**
(dollars)




**Net Earnings from Continuing Operations before Unusual Items**
(millions of dollars)



**Richard F. Haskayne**
*Chairman of the Board*

**Harold N. Kvisle**
*President and Chief Executive Officer*

# LETTER TO SHAREHOLDERS

*2001 Annual Report*

**2001 was a challenging year for North Americans, in business and in our personal lives. Like others, the people of TransCanada rose to the challenges of September 11th, delivering natural gas and electric power to all our customers in Canada and the United States without disruption. TransCanada also weathered the financial turmoil of late 2001 better than most. We are pleased that the difficult decisions taken in 1999 and 2000 have positioned the company to perform strongly throughout the business cycle.**

**TransCanada exceeded our key performance objectives in 2001, generating strong earnings and cash flow and further strengthening our financial position. Details are provided on the previous page. TransCanada has now completed the restructuring that began in late 1999, and we look forward to growing and prospering in our chosen businesses of natural gas transmission and electric power.**

## DELIVERING STRONG TEAM PERFORMANCE

TransCanada today is about spirit, confidence and focus. Over the past two years our operating, development and corporate teams have achieved significantly higher levels of performance, and further accomplishments will come through continuous improvements in the way we do business. Our leadership team is smaller and more focused and we are proud of the results we have already achieved. The people of TransCanada are second to none, and we take this opportunity to thank them for their dedication and commitment. TransCanada's 2001 achievements are a direct result of their efforts.

TransCanada aspires to be the most profitable, competitive and reliable provider of natural gas transportation and power services across the northern tier of North America. Throughout the company, we are acutely focused on cost control, cost optimization, and safe, reliable operations. We are fully committed to operational excellence in both gas transmission and electric power.

In 2001, we saw excellent results from performance incentive arrangements in our regulated gas transmission business. Under those arrangements, we're motivated to reduce costs and improve performance to the benefit of both TransCanada and our highly valued customers. We believe incentive arrangements will be an important part of our regulated business model in future years.

## SEIZING OPPORTUNITIES FOR GROWTH

We expect the next ten years will be the most exciting period in the history of TransCanada. We are constantly evaluating opportunities with an emphasis on new developments and strategic acquisitions that add significant shareholder value.

Economic forecasts indicate there will be a significant increase in North American natural gas demand over the next decade. Much of the projected increase will come from markets that TransCanada serves today. In the near term, we are focused on connecting new supplies of western Canadian gas and delivering that gas to our northern tier markets. Longer term, Mackenzie Delta and Alaska gas will be attractive incremental sources, and we look forward to connecting those sources within five to ten years.

TransCanada is well positioned to make a strong contribution to the development of northern gas. We have extensive large diameter, cold weather natural gas pipeline experience, and a ten-year track record of bringing large pipeline projects in on budget. Our integrated Alberta to New York pipeline system is one of the most efficient, large volume systems anywhere. We can expand that system and our pipelines to other markets to accommodate incremental volumes at low cost and with considerable flexibility. These are real advantages that underpin our proposals to build and operate northern gas infrastructure.

Our power business continues to grow at an impressive rate and performed particularly well in 2001. While our power assets constitute the smaller portion of our balance sheet, our power business offers significant potential for growth and value creation particularly over the short term. We invested more than $550 million to grow our power business in 2001, notably without having to raise external funds.

**TransCanada today is about spirit, confidence and focus.**

We have established solid credentials as a power developer with a strong focus on cogeneration, and we will continue to pursue development opportunities across Canada and in selected regions of the U.S. Our Alberta and New England deregulation experiences have given us considerable insight when assessing new jurisdictions. We are prepared to pursue development opportunities in both Canada and the U.S. when the fundamentals are right.

## BOARD AND MANAGEMENT

It is with great sadness that we marked the passing in 2001 of J.M. (Jack) MacLeod, an active and valued member of the Board of Directors. Mr. MacLeod joined the board of NOVA Corporation in 1993. He served with distinction on the TransCanada board as Chair of the Health, Safety and Environment Committee and as a member of the Governance Committee.

This year will see the retirement from the board of The Hon. Donald S. Macdonald after ten years of service. Dominic D'Alessandro, elected to the board in 1999, will not be standing for re-election. We would like to thank both gentlemen for their contributions and dedication to TransCanada.

There are two new appointments to the board, Mr. David P. O'Brien, Chairman and CEO of PanCanadian Energy Corporation; and The Hon. Paule Gauthier, P.C., O.C., O.Q., Q.C., Senior Partner, Desjardins Ducharme Stein Monast. We welcome both and look forward to the unique talents each brings to the board.

We take this opportunity to acknowledge the contribution of Mr. Douglas D. Baldwin as President and CEO during the period from July 1999 through April 2001. Mr. Baldwin stepped forward to assume leadership of TransCanada at a difficult time and initiated the re-organization and divestment program that restored TransCanada's financial health and competitive position. Mr. Baldwin continues as a valued member of the board.

In conclusion, TransCanada enjoyed considerable success in 2001, and we look forward to building on that success in 2002 and beyond. We will invest in projects we understand, in regions and markets we know well and in circumstances where we have a clear competitive advantage. Through astute investments and excellent operations, we will continue to add value and deliver growth for our shareholders.

R.F. Haskayne

**RICHARD F. HASKAYNE**
*Chairman of the Board*

**HAROLD N. KVISLE**
*President and Chief Executive Officer*

**Russ Girling**
*EVP and Chief Financial Officer*

**Hal Kvisle**
*President and Chief Executive Officer*

**Ron Turner**
*EVP, Operations and Engineering*

**Dennis McConaghy**
*EVP, Gas Development*

## Q & A

**Q** ***Is there an appropriate level of competition in the natural gas pipeline business in Canada? Is it a good business for TransCanada?***

**A** Regulators, producers and pipeline operators have made major strides in recent years, introducing elements of a competitive structure to the Canadian natural gas pipeline industry. However, we still have some way to go before we achieve a business model that fosters competition without undue risk of over-building.

Rates of return on Canadian regulated pipelines are lower than in the United States. This limits our enthusiasm for further pipeline investments in Canada and that is frustrating – we genuinely want to serve our Canadian customers and we find it difficult to do so when Canadian returns are not competitive. In an increasingly continental energy market, it's in Canada's best interest to have strong Canadian pipeline companies that can move quickly to add capacity as required. To attract TransCanada's capital, our pipeline business needs to earn a fair return. That is the reason for our Fair Return Application before the National Energy Board.

**Q** ***What is TransCanada doing to better serve its customers?***

**A** We envision a responsive pipeline industry that offers a menu of services and pricing, along with the cost-effective reliability our customers have come to expect. TransCanada is taking a leadership role in articulating a new vision for the natural gas pipeline industry in Canada – one that reflects a new regulatory framework and offers real customer choice. We see our Alberta System evolving as the western hub, serving western producers and consumers, and our central Canada system evolving as an eastern hub, serving consumers in Ontario, Quebec and the eastern U.S. The steps to achieve this vision include clarifying the regulatory jurisdiction of our mainlines within Alberta; facilitating a trading hub in central Canada; establishing a new toll regime; and expanding export connections to the U.S. In January 2002, we began to share a discussion paper outlining our vision – over the course of the year we'll be working collaboratively with stakeholders toward these goals.

**Q** ***How is TransCanada positioning itself for a role in the development of northern gas reserves?***

**A** TransCanada is well positioned to play a key role in bringing natural gas from the Mackenzie Delta and Alaska to market. We are working to ensure Arctic natural gas ties into our system, which provides the greatest access to North American markets. Our experience and expertise in building and operating cold weather natural gas pipeline systems is unmatched in North America, as is our track record of bringing major pipeline projects in on time and on budget. TransCanada believes it makes sense to use spare capacity in our existing systems and augment that capacity as needed, giving customers considerable flexibility and minimizing up-front investment.

**Al Bellstedt**
*EVP, Law and General Counsel*

**Alex Pourbaix**
*EVP, Power Development*

**Sarah Raiss**
*EVP, Corporate Services*

## Q & A

**Q** ***When will a northern pipeline become a reality?***

**A** The Alaska Highway and Mackenzie Valley pipelines will proceed when producers are ready to develop the gas reserves and commence production, and when regulatory approvals are in place. Once the pipeline approvals and logistics are in place, each pipeline will take approximately two years to construct. Given this schedule, we expect it will be five to ten years before either pipeline is operating.

We are convinced that gas from both Prudhoe Bay and the Mackenzie Delta will be needed to offset declines from existing basins and meet growing demand. The combined initial volumes from Prudhoe Bay and the Mackenzie Delta will be less than five per cent of North American gas demand. We expect the North American market will absorb those volumes very quickly.

**Q** ***Recently, you've had spare capacity on your pipeline systems. What steps are you taking to fill the pipe?***

**A** First, it's important to understand that spare capacity is not necessarily a bad thing. Through the 1990s, western Canadian producers were plagued by a shortage of pipeline capacity as production grew faster than new pipeline capacity could be approved and constructed. Gas that could have been exported to strong markets in the U.S. was trapped in Canada, resulting in wide price differentials and weak wellhead prices. This was an undesirable outcome that could have been avoided if there had been some mechanism to ensure a reasonable amount of spare capacity. We have committed to producers that we will do everything we can, working with them, to ensure there is never again a shortage of capacity.

Our current spare capacity enables us to quickly and effectively capture new supply opportunities. By maintaining spare capacity in Alberta and on our Canadian Mainline, we are able to accept incremental gas on short notice under short-term contracts – we could not do that when our pipes were running at capacity. Our flexibility and rapid response enabled us to capture the largest share of gas volumes from Ladyfern, one of the most significant gas discoveries in Western Canada in many years. Most of the Ladyfern gas is moving from British Columbia onto our Alberta System, from which it can be transported virtually anywhere in North America.

TransCanada is also working with industry to optimize our rates and service offerings to increase the value of our transportation capacity to customers.

**Q** ***In light of the difficulties faced by many energy companies in the latter half of 2001, what is your outlook for TransCanada?***

**A** We believe it's a good time for TransCanada to grow our core businesses of natural gas transmission and electric power. The longer-term business fundamentals remain strong with increased demand for both natural gas and electricity driven by population and economic growth.

At the same time, in the wake of the uncertainty in the energy sector in late 2001, we've experienced a renewed focus on credit quality, strong capitalization and stable operations. For TransCanada, where we've spent the last several years focusing our efforts on growing our core businesses, divesting non-core assets, reducing our debt and strengthening our balance sheet, this is a positive development. We continue to maintain 'A' category ratings with a stable outlook on our senior unsecured debt. Our credit rating, combined with our financial strength and flexibility, positions us to move quickly to acquire strategic assets. Our approach to growth will be opportunistic but deliberate.

**Q** ***Why is TransCanada – traditionally known as a natural gas pipeline company – moving aggressively into power?***

**A** A natural synergy exists between our pipeline and power businesses. Both businesses are capital intensive and require similar technical expertise. Both are driven by similar fundamentals – 40 to 50 per cent of the projected increase in demand for natural gas comes from power generation projects. In the current environment, with power offering higher returns than our Canadian regulated pipelines, we foresee strong earnings contributions from power developments and acquisitions.

**Q** ***Over the past three years, TransCanada has undergone significant change. How has this affected your workforce?***

**A** The transformation of the NOVA Gas Transmission and TransCanada organizations – two diversified, international companies with long-established corporate cultures – into one North American energy company posed numerous challenges. We had to make many difficult decisions that impacted our employees, yet we were able to successfully face those challenges through the commitment of our talented workforce. With the most significant organizational changes now behind us, we are committed to fostering a working environment that inspires excellence and positions us as one of the top employers in Canada.

We're continually working to evolve a new culture for TransCanada, strengthening the alignment of our human resource practices with our strategy, our company's values and our strong resolve to be competitive and create value for our customers and shareholders.

**Q** ***As a key player in the energy industry, what is TransCanada's position on Climate Change?***

**A** Climate Change is a complex issue that TransCanada takes very seriously. We have made considerable progress reducing our greenhouse gas (GHG) emissions as part of a larger effort to improve the combustion efficiency of our pipeline compression and power generation equipment.

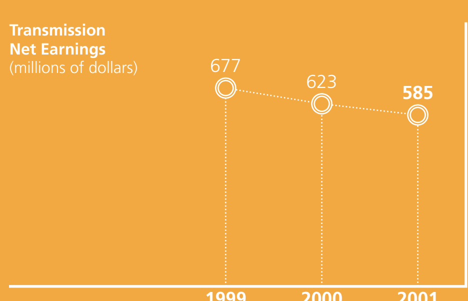
TransCanada supports voluntary efforts to reduce GHG emissions and we've made exceptional progress over the past five years. Our voluntary efforts are focused on technical and operational improvements – we think operating initiatives that reduce GHG at the source are more important than other mechanisms such as international emissions trading and offset credits. We are encouraging the Canadian Government to work closely with our North American Free Trade Agreement partners to develop North American solutions that focus on emission reductions at the source.

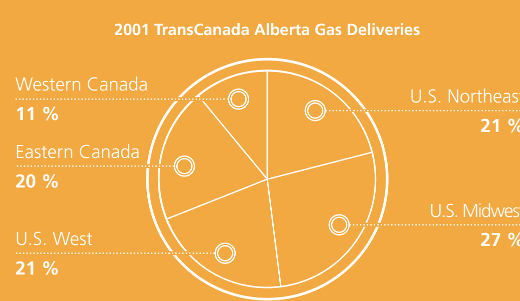
Air quality is an equally important issue, particularly in urban environments. TransCanada is working to minimize emissions of sulphur oxides ($SO_x$), nitrogen oxides ($NO_x$) and other pollutants by monitoring our operations more closely and by installing cleaner-burning equipment where it will make a difference.

Combustion efficiency is our third important issue and a key element of our greenhouse gas and air quality initiatives. More efficient pipeline compressors and power generators consume less fossil fuel, conserving valuable energy resources and reducing greenhouse gas and other emissions. TransCanada is committed to a leadership role in combustion efficiency and we look forward to continuing progress in the near term and over the longer term.

Operating more than 38,000 kilometres (24,000 miles) of pipelines transporting trillions of cubic feet of natural gas each year, we are the largest natural gas pipeline company in Canada and one of the largest in North America. We've been transporting natural gas since 1958. Our pipeline system links the rich natural gas resources of the Western Canada Sedimentary Basin (WCSB) – one of North America's largest, most cost-competitive sources of natural gas – to markets across Canada and the United States. We own, operate and have interests in natural gas pipelines in both Canada and the U.S. We are also the general partner of TC PipeLines, LP, a limited partnership that owns interests in U.S. pipelines. We're well positioned to play a key role in bringing northern gas to the growing North American marketplace.

# TRANSMISSION *of* NATURAL GAS



## TRANSMISSION OF NATURAL GAS

### CORE STRENGTHS

- *Unparalleled Market Access:* We are the leaders in connecting western Canadian natural gas supply with the premier markets of California, Eastern Canada and the northern tier of the U.S. Our extensive infrastructure gives us a strategic position in the continental market, offering producers the connectivity, penetration and flexibility they need to capitalize on growing demand.

- *Experience and Expertise:* After more than 50 years in business, TransCanada continues to be at the forefront of pipeline technology. We are experienced in building and operating natural gas pipelines in extreme climates and all terrains. We are the leading global operator of large gas turbine compressor stations, and the operator of one of the largest, most sophisticated computer-controlled pipeline networks in the world.

**We're focused on making customer needs a top priority.**

- *Customer Focus:* From effectively managing capacity – quickly connecting new supply and responding to market needs – continually driving costs down by utilizing and applying innovation and best practices, we're focused on making customer needs a top priority. Customer satisfaction surveys reinforce our industry leadership in areas critical to our customers including preferred market access and user-friendly transactional systems. Our emphasis is on making it easier to do business with TransCanada by delivering efficient, hassle-free service.

### GROWTH STRATEGY AND OPPORTUNITIES

- *Attract Incremental Western Canadian Supply:* TransCanada is well positioned to take advantage of new and incremental sources of natural gas from all parts of Alberta, northeast British Columbia and the rest of the WCSB. Maintaining unrestricted access, moving quickly to connect new sources, expanding our delivery capacity and investing in strategic extensions to our systems in Western Canada will enable us to increase our throughput and reduce unit costs for all customers.

- *Capitalize on Increased Demand for Natural Gas:* North American demand for natural gas is projected to increase 20 billion cubic feet per day (or 29 per cent) by 2010, with electricity generation driving nearly half of this growth in gas demand. TransCanada already plays a key role connecting western supply with growing demand in major North American markets – we know the markets well. Through expansion of our existing systems, new extensions and strategic growth in our partly owned U.S. pipelines, we intend to capitalize on increased demand, adding value to our bottom line.

- *Bring Northern Natural Gas to Market:* We've placed a strategic priority on the development of two pipelines to connect natural gas from the Northwest Territories and Alaska to our system in Alberta. Our existing infrastructure is uniquely positioned to take Arctic gas and redeliver it to key northern tier markets, at a significantly lower cost and with greater flexibility than a single "bullet" pipeline. TransCanada owns 50 per cent of Foothills Pipe Lines Ltd., which has the existing "southern pre-build" infrastructure in place for the Alaska Highway pipeline project. TransCanada and Foothills are working with eight other pipeline companies to develop a proposal for Alaska producers that will help move Alaska North Slope natural gas to markets in Canada and the lower 48 states.

  TransCanada is also prepared to play a leadership role in the Mackenzie Valley pipeline initiative. We have developed a plan to accommodate Mackenzie Delta gas in our Alberta system and we are prepared to extend that system northward if the Delta producers wish us to do so. Our credentials and track record in big-inch construction, large compressor stations, cold climates, and remote facility control are unequalled in North America. We look forward to applying our expertise to the development and operation of northern gas pipelines.

## TRANSMISSION OF NATURAL GAS

### 2001 ACCOMPLISHMENTS

#### IMPROVING OPERATIONAL EFFICIENCY

In 2001, TransCanada was successful in negotiating a fuel gas incentive program as part of the overall tolls settlement that was ultimately approved by the National Energy Board (NEB) in November. The purpose of this program is to provide TransCanada with an additional incentive to minimize total delivered costs (toll for transportation plus fuel), while achieving an acceptable balance between cost savings and level of service.

*The agreement reflects alignment of interests between TransCanada and our customers, and sets the stage for all parties to win – TransCanada can improve our earnings while customers benefit from lower cost. Improved operational efficiency also produces environmental benefits, to the extent that combustion-related emissions to the atmosphere are minimized, supporting TransCanada's efforts to reduce our environmental footprint.*

#### LOWEST CAPITAL COST PERFORMANCE

The results from a 2001 benchmark study confirm that TransCanada has been, and continues to be, the lowest cost provider of safe and reliable natural gas pipeline facilities. Out of more than 1,000 of the top quartile (lowest cost) projects in NEB and U.S. Federal Energy Regulatory Commission databases, TransCanada's total installed capital costs were lower than any of the other competitors.

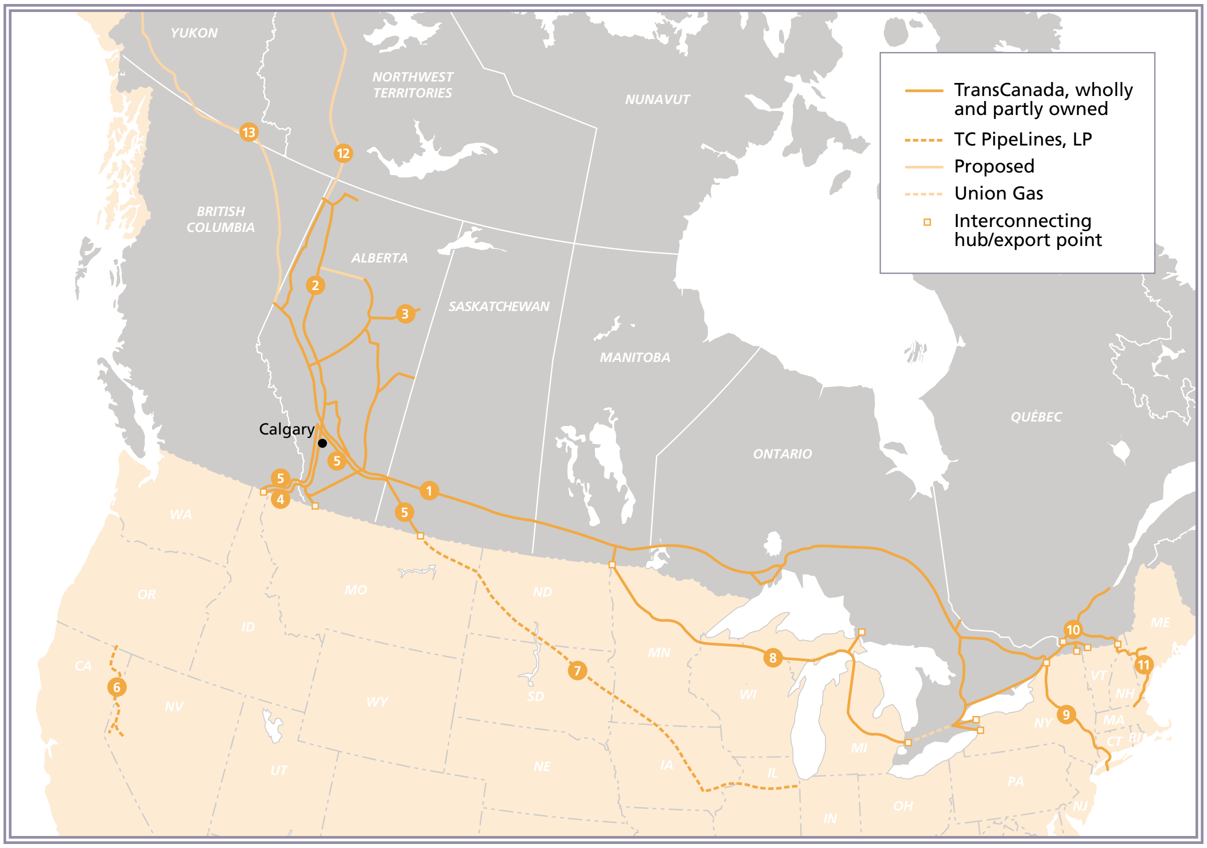
*In addition to installing these facilities at the absolute lowest cost, TransCanada has been consistently on budget and on schedule. During the 1990s, TransCanada's capital program approached $14 billion and was delivered within 0.6 per cent of the budgeted amount. Over 95 per cent of the projects were delivered within two months of the originally scheduled in-service date. Our success can be attributed to our extensive project management experience, our ability to develop effective relationships with key stakeholders and our implementation of leading-edge pipeline technologies such as high-strength steels and mechanized welding.*

#### INDUSTRY LEADING E-COMMERCE INITIATIVES

In 2001, TransCanada introduced new electronic services including e-billing, e-contracting and wireless access to reporting, enabling our customers to streamline their business processes while lowering our costs. TransCanada Freedom is TransCanada's well-received wireless service that allows customers to access important account status reports using a personal digital assistant (PDA). While this information is already available electronically, TransCanada Freedom frees customers from their office computers by offering access at any time and from virtually anywhere. Launched in spring 2001, TransCanada Freedom is the first wireless application of its kind in the pipeline industry in North America.

*While we move forward with our proposal for a new competitive business and regulatory framework that will allow us to meet customer needs more effectively over the long term, we continue to execute continuous improvement initiatives in our customer service and sales processes. TransCanada is an industry leader in utilizing e-commerce to improve customer service and, at the same time, to lower costs.*

## TRANSMISSION OF NATURAL GAS




*Saskatchewan, Manitoba, Ontario, Québec*

**1 Canadian Mainline**
*(100% TransCanada)*
LENGTH: 14,900 km
2001 THROUGHPUT: 6.7 Bcf/d

*Alberta*

**2 Alberta System**
*(100% TransCanada)*
LENGTH: 22,500 km
2001 THROUGHPUT: 11.1 Bcf/d

**3 TransCanada PipeLine Ventures Limited Partnership**
*(100% TransCanada)*
LENGTH: 137 km
2001 THROUGHPUT: 0.2 Bcf/d

*British Columbia*

**4 British Columbia System**
*(100% TransCanada)*
LENGTH: 180 km
2001 THROUGHPUT: 1.1 Bcf/d

*British Columbia, Alberta, Saskatchewan*

**5 Foothills Pipe Lines Ltd.**
*(50% ownership Foothills Pipe Lines Ltd.; TransCanada: 69.5% Saskatchewan segment; 74.5% Alberta segment; 74.5% B.C. segment)*
LENGTH: 1,040 km
2001 THROUGHPUT: 3.1 Bcf/d

*Oregon, California, Nevada*

**6 Tuscarora Gas Transmission Company**
*(1% TransCanada directly; 16.4% indirectly through TC PipeLines, LP)*
LENGTH: 369 km
2001 THROUGHPUT: 0.1 Bcf/d

*Montana, North Dakota, South Dakota, Minnesota, Iowa, Illinois, Indiana*

**7 Northern Border Pipeline Company**
*(10% TransCanada indirectly through TC PipeLines, LP)*
LENGTH: 2,010 km
2001 THROUGHPUT: 2.3 Bcf/d

*Minnesota, Wisconsin, Michigan*

**8 Great Lakes Gas Transmission Limited Partnership**
*(50% TransCanada)*
LENGTH: 3,387 km
2001 THROUGHPUT: 2.2 Bcf/d

*New York, Connecticut*

**9 Iroquois Gas Transmission System**
*(40.96% TransCanada)*
LENGTH: 604 km
2001 THROUGHPUT: 0.9 Bcf/d

*Québec*

**10 Trans Québec and Maritimes Pipeline Inc.**
*(50% TransCanada)*
LENGTH: 572 km
2001 THROUGHPUT: 0.4 Bcf/d

*Maine, New Hampshire*

**11 Portland Natural Gas Transmission System**
*(33.29% TransCanada)*
LENGTH: 471 km
2001 THROUGHPUT: 0.1 Bcf/d

*Alberta, Northwest Territories*

**12 Mackenzie Valley Extension**
*(proposed by producers)*

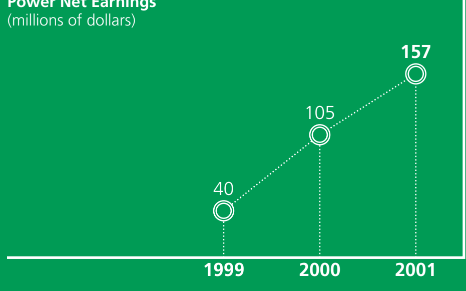
*Alaska, Yukon, British Columbia, Alberta*

**13 Alaska Highway Pipeline**
*(proposed by Foothills Pipe Lines Ltd. which is 50% owned by TransCanada)*

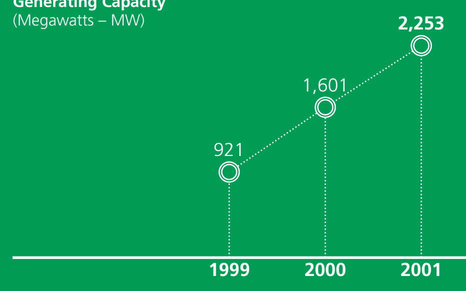
**TransCanada generates the energy that powers hundreds of thousands of businesses, institutions and households throughout Canada and the United States. A rapidly emerging player in the North American power market, we build, own, manage and operate some of the most efficient power plants on the continent. We utilize a diversified range of fuel sources: natural gas, waste heat, waste wood, or hydropower. We own one of the largest natural gas-fired power plants in the northeast U.S. We are the largest unitholder in TransCanada Power, L.P., a publicly-held limited partnership that owns power plants in both countries. We also market electricity across Canada and the northern tier of the U.S. and manage and supply electricity requirements for a wide range of industrial clients.**

# GENERATION *of* POWER

**Power Net Earnings**
(millions of dollars)




**Generating Capacity**
(Megawatts – MW)



## GENERATION OF POWER

### CORE STRENGTHS

- *Broad Understanding of Continental Markets:* We have extensive knowledge of North American energy markets, underscored by an in-depth understanding of our core markets in the northeastern U.S., Ontario and the Pacific Northwest, and excellent relationships with industrial customers. As an active participant in the deregulation of the Alberta power sector, we are now one of the largest power suppliers and marketers of power to industrial customers in the province. Our significant experience with deregulation there and in New England will serve us well in seizing opportunities in newly opening markets.

- *Ability to Structure Deals and Manage Risk:* In today's power markets, the ability to structure deals and manage risk is critical to mitigating volatility and uncertainty for our industrial customers as well as our shareholders. Our deal structuring and risk management skills have been a key element of our success, complemented by marketing and trading operations that enable us to take advantage of market volatility while creating stable and predictable cash flow.

**Power offers TransCanada significant potential for growth over the next five years.**

- *Commitment to Excellence:* TransCanada's power business is characterized by a commitment to industry-leading performance, as evidenced by our highly efficient generating fleet of turbines that operates at average availability exceeding 96 per cent. We have a strong management team with a proven track record in maximizing value from existing assets and in identifying new opportunities that leverage our skills and competitive strengths.

### GROWTH STRATEGY AND OPPORTUNITIES

- *Grow in Markets We Know:* The northern tier is one of the fastest growing areas of North America, with a projected increase in total power generation of approximately ten per cent by 2005. Utilizing our expertise in cogeneration and our experience with diversified fuel sources, TransCanada will continue to build, acquire and invest in competitive facilities and relationships, growing our balanced portfolio of both gas-fired and non gas-fired power plants in regions where we have existing competitive advantages.

- *Optimize Reward Versus Risk:* Our objective is to grow our power business in a manner that contributes to continued earnings growth. That means applying business models that benefit from, and support, our strong balance sheet. It means pursuing projects that fit our desired risk profile – a focus on low-cost supply, low volatility, stable returns and longer-term contracts. Our financial strength allows us to move quickly to act on quality opportunities as they arise.

- *Maximize Returns Through a Broad Suite of Power Products:* Growth of our power business will be fueled by a combination of our physical assets and our trading and marketing capability. By offering our customers value-added power products and services, we maximize their returns while reducing business risk. By proactively managing our own power portfolio, we gain valuable market knowledge, enabling us to optimize the value of our assets and contribute to continued growth and shareholder value.

## GENERATION OF POWER

### 2001 ACCOMPLISHMENTS

#### ADDING VALUE THROUGH TIMELY AND STRATEGIC ACQUISITIONS

In December 2001, TransCanada partnered with AltaGas Services Inc. to purchase the remaining rights and obligations of the 706 megawatt (MW) Sundance B power purchase arrangement (PPA) from Enron Canada Power Corp. The purchase represents a significant and extremely competitive source of power in Alberta. Previously, TransCanada acquired 100 per cent of the generating capacity of the 560 MW Sundance A power plant under similar arrangements.

*Because we're continually evaluating acquisitions in Canada and the U.S., we know what we want and we know what makes sense for TransCanada. The Sundance B PPA purchase demonstrated our ability to act quickly and decisively on the opportunity to acquire new capacity at the low end of the supply cost curve. We were able to put in place immediately the infrastructure to manage our investment and market the facility's output.*

#### BUILDING GEOGRAPHIC AND FUNCTIONAL DIVERSIFICATION

TransCanada's diversified portfolio of managed and owned power assets ranges from its Williams Lake plant, the largest biomass fueled plant in North America, to enhanced combined-cycle plants in Ontario that efficiently utilize waste heat from the company's Canadian Mainline compressor stations to generate power. In the first half of 2001, TransCanada added hydroelectric power through the acquisition of the Curtis Palmer Hydroelectric Company and its two plants in New York.

*The Curtis Palmer acquisition provides us with additional clean, low marginal cost power in the U.S. northeast, adding to our existing facilities in New York and Rhode Island. The entire output of the plants, approximately 60 MW, is sold under a fixed-price, long-term agreement with a remaining term of more than 25 years. As a stable source of income in one of the fastest-growing power markets on the continent, Curtis Palmer fits our objective of growing our power business through strategic, disciplined and profitable investments.*

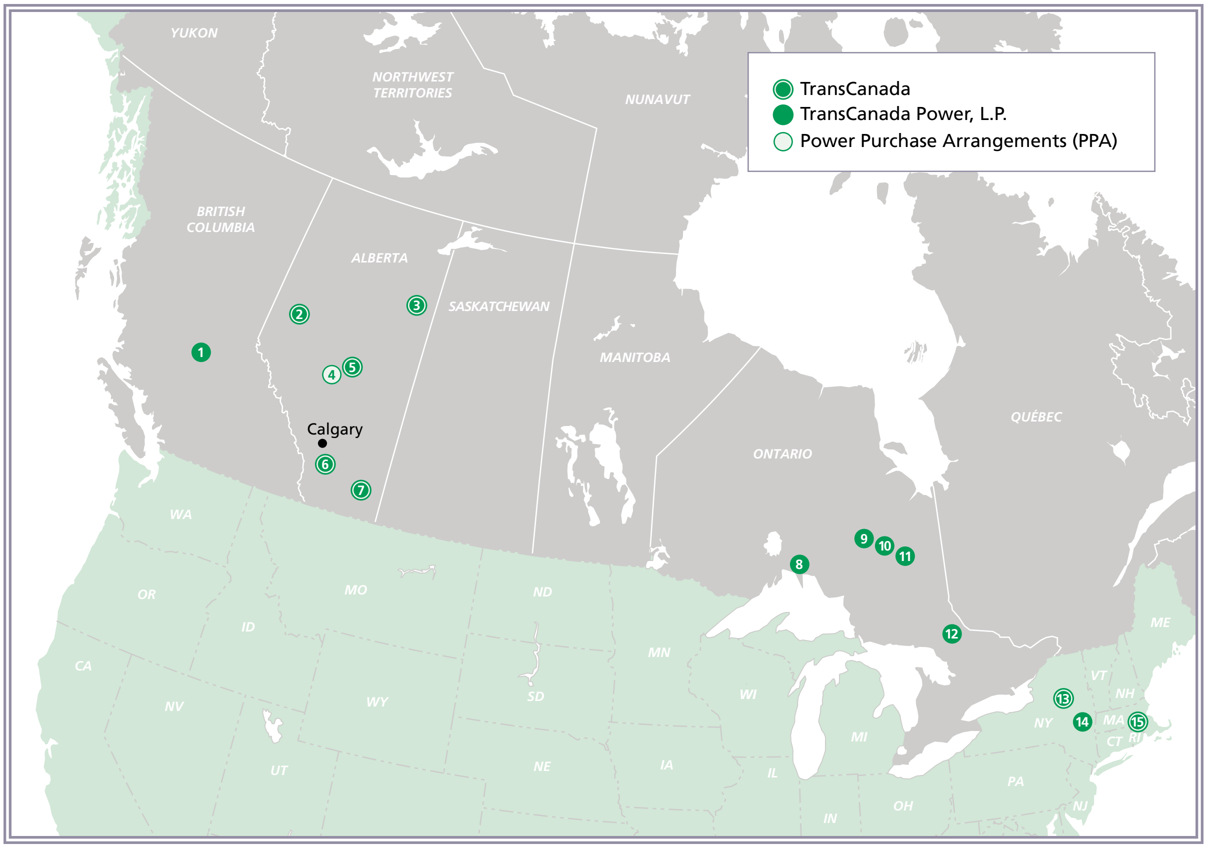
#### BUILDING OUR STRENGTHS IN COGENERATION

Cogeneration is a fuel-efficient, low-cost method of power generation that uses excess heat captured from natural gas-fired electricity production to generate a second energy source. In 2001, TransCanada completed construction of two cogeneration plants near Redwater and Carseland, Alberta, on time and on budget, adding to the company's expanding portfolio of cogeneration plants. TransCanada's experience and reputation in tailoring cogeneration facilities to the specific needs of its commercial customers and partners were instrumental in securing two new major cogeneration projects in Alberta in 2001.

*The 165 MW MacKay River cogeneration plant, located at Petro-Canada's MacKay River in-situ oil sands project, will be the first large-scale cogeneration plant in the Alberta Oil Sands, and will establish the model for future cogeneration plants in the area. The plant will reduce total greenhouse gas emissions by about 50 per cent compared to the equivalent supply of steam and electricity without cogeneration.*

*The Bear Creek cogeneration plant will provide electricity and steam to Weyerhaeuser Company's Grande Prairie Pulp Mill and will use natural gas as well as biomass-derived steam from the adjacent mill to provide power to all eight manufacturing facilities in Weyerhaeuser's Alberta operations. The project will enable Weyerhaeuser to reduce significantly the amount of wood waste sent to landfill.*

## GENERATION OF POWER




*British Columbia*

**1 Williams Lake**
MW: 66
CONFIGURATION: biomass
FUEL: wood waste
IN-SERVICE DATE: April 1993

*Alberta*

**2 Bear Creek**
*(under construction)*
MW: 80
CONFIGURATION: combined cycle cogeneration
FUEL: natural gas and wood waste
IN-SERVICE DATE: Winter 2002

**3 MacKay River**
*(under construction)*
MW: 165
CONFIGURATION: cogeneration
FUEL: natural gas and produced gas
IN-SERVICE DATE: Fall 2003

**4 Sundance A**
MW: 560
ACQUIRED: August 2000
EFFECTIVE DATE: January 2001

**4 Sundance B**
*(50% TransCanada)*
MW: 706
ACQUIRED: December 2001
EFFECTIVE DATE: December 2001

**5 Redwater**
MW: 40
CONFIGURATION: cogeneration
FUEL: natural gas and regeneration gas
IN-SERVICE DATE: December 2001

**6 Carseland**
MW: 80
CONFIGURATION: cogeneration
FUEL: waste heat and natural gas
IN-SERVICE DATE: December 2001

**7 Cancarb**
MW: 27
CONFIGURATION: waste heat recovery
FUEL: waste heat and natural gas
IN-SERVICE DATE: January 2001

*Ontario*

**8 Nipigon**
MW: 40
CONFIGURATION: enhanced combined cycle
FUEL: waste heat and natural gas
IN-SERVICE DATE: May 1992

**9 Calstock**
MW: 35
CONFIGURATION: enhanced biomass
FUEL: waste wood and waste heat
IN-SERVICE DATE: October 2000

**10 Kapuskasing**
MW: 40
CONFIGURATION: enhanced combined cycle
FUEL: waste heat and natural gas
IN-SERVICE DATE: March 1997

**11 Tunis**
MW: 43
CONFIGURATION: enhanced combined cycle
FUEL: waste heat and natural gas
IN-SERVICE DATE: January 1995

**12 North Bay**
MW: 40
CONFIGURATION: enhanced combined cycle
FUEL: waste heat and natural gas
IN-SERVICE DATE: March 1997

*New York*

**13 Curtis Palmer**
MW: 60
CONFIGURATION: hydroelectric
FUEL: water
IN-SERVICE DATE: Curtis – 1910 (restored in 1985), Palmer – 1985

**14 Castleton**
MW: 64
CONFIGURATION: combined cycle cogeneration
FUEL: natural gas and #2 fuel oil
IN-SERVICE DATE: March 1992

*Rhode Island*

**15 Ocean State**
MW: 560
CONFIGURATION: combined cycle
FUEL: natural gas and #2 fuel oil
IN-SERVICE DATE: Unit 1 – 1990, Unit 2 – 1991

(Ownership is 100% unless otherwise stated.)

## MANAGEMENT'S DISCUSSION AND ANALYSIS

*Management's Discussion and Analysis should be read in conjunction with the audited Consolidated Financial Statements of TransCanada PipeLines Limited (TransCanada or the company) and the notes thereto for the year ended December 31, 2001.*

### CONSOLIDATED FINANCIAL REVIEW

#### HIGHLIGHTS

***Earnings Increase:*** TransCanada's net income applicable to common shares from continuing operations (net earnings), before unusual items, increased $78 million or 13 per cent to $670 million or $1.41 per share in 2001 compared to $592 million or $1.25 per share in 2000. There were no unusual items in 2001. In 2000, unusual items included $30 million gains from asset sales from continuing operations and $28 million of positive adjustments related to tax law and income tax rate changes.

***Cash Flow Increase:*** Funds generated from continuing operations increased $231 million or 18 per cent to $1.514 billion in 2001 compared to 2000.

***Balance Sheet Strengthened:*** In 2001, TransCanada continued to strengthen its balance sheet through the realization of proceeds of $1.17 billion from the sale of non-core assets and funds generated from operations. The company reduced debt and redeemed preferred securities by approximately $1.1 billion.

***Dividend Increase:*** On January 29, 2002, the Board of Directors of TransCanada raised the quarterly dividend on the company's outstanding common shares 11 per cent from $0.225 per share to $0.25 per share for the quarter ended March 31, 2002.

***Divestitures Substantially Complete:*** At December 31, 2001, TransCanada had sold substantially all of its non-core businesses.

TransCanada's strategic direction to capture North American energy growth opportunities by focusing on its core businesses of Transmission and Power and to divest assets of non-core businesses has resulted in increased profitability and strengthened the company's balance sheet at December 31, 2001. In 2001, proceeds from divestitures and strong internally generated cash flow allowed TransCanada to fund debt maturities of $793 million, redeem preferred securities of $318 million and invest approximately $1.0 billion in its operations. The increases in earnings and cash flow combined with the solid balance sheet provides TransCanada the financial flexibility to continue to grow its core businesses.

**CONSOLIDATED RESULTS-AT-A-GLANCE**

**Year ended December 31** (millions of dollars except per share amounts)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| **Net Income/(Loss) Applicable to Common Shares** | | | |
| Net earnings before unusual items | 670 | 592 | 515 |
| Unusual items | – | 58 | (61) |
| Net earnings from continuing operations | 670 | 650 | 454 |
| Net (loss)/income from discontinued operations | (67) | 61 | (534) |
| | 603 | 711 | (80) |
| **Net Income/(Loss) Per Share – Basic and Diluted** | | | |
| Net earnings per share before unusual items | $ 1.41 | $ 1.25 | $ 1.07 |
| Unusual items per share | – | 0.12 | (0.13) |
| Net earnings per share from continuing operations | 1.41 | 1.37 | 0.94 |
| Net (loss)/income per share from discontinued operations | (0.14) | 0.13 | (1.13) |
| | $ 1.27 | $ 1.50 | $ (0.19) |

Net income applicable to common shares for the year ended December 31, 2001 was $603 million or $1.27 per share after reflecting a net loss from discontinued operations of $67 million or $0.14 per share. This compares to net income of $711 million or $1.50 per share in 2000, which included net income from discontinued operations of $61 million or $0.13 per share, and a net loss of $80 million or $0.19 per share in 1999, which included a net loss from discontinued operations of $534 million or $1.13 per share.

TransCanada's net earnings before unusual items for the year ended December 31, 2001 were $670 million or $1.41 per share compared to $592 million or $1.25 per share for 2000 and $515 million or $1.07 per share in 1999. Higher earnings from the Power business, as well as reduced financial and preferred equity charges due to lower net debt balances and preferred securities and preferred share redemptions were the primary contributors to the increase over 2000 and 1999 results. Lower earnings from the Transmission business in 2001 partially offset the improved results from the other segments. Also reflected in the 2001 results are the benefits from the company's continued commitment to cost reductions. As a result of initiatives undertaken throughout TransCanada's businesses, the company achieved annual pre-tax operating cost savings of approximately $55 million in 2001, $60 million in 2000 and $95 million in 1999. The cost savings were primarily delivered by TransCanada's Transmission business and have been shared between its customers and shareholders.

Net earnings from continuing operations in 2001, after unusual items, were $670 million compared to $650 million and $454 million in 2000 and 1999, respectively. There were no unusual items reported in 2001. The $58 million of unusual items included in the 2000 net earnings from continuing operations consisted of gains on the sale of assets amounting to $30 million, after tax, or $0.06 per share, and tax recoveries of $28 million or $0.06 per share, reflecting the impact of tax law and income tax rate changes in the February 2000 and October 2000 Federal budgets. The $61 million of unusual items included in the 1999 net earnings from continuing operations consisted of restructuring and other costs of $108 million, after tax, or $0.23 per share, partially offset by a $47 million, after tax, or $0.10 per share gain on the sale of a portion of TransCanada's investment in Northern Border Pipeline Company (Northern Border).

TransCanada's results in 2001 reflect the plan approved by the Board of Directors in July 2001 to dispose of the Gas Marketing business which is included in discontinued operations. All prior period comparative results have been restated to reflect Gas Marketing as discontinued operations. The 2001 net loss from discontinued operations of $67 million is comprised of a positive $20 million after-tax adjustment to the provision for loss on discontinued operations originally recorded in 1999 relating to the December 1999 divestiture plan (December Plan) and an $87 million after-tax charge relating to Gas Marketing.

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

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| Transmission | 585 | 623 | 677 |
| Power | 157 | 105 | 40 |
| Corporate | (72) | (78) | (263) |
| Continuing operations | 670 | 650 | 454 |
| Discontinued operations | (67) | 61 | (534) |
| **Net Income Applicable to Common Shares** | 603 | 711 | (80) |

## TRANSMISSION

### HIGHLIGHTS

***Net Earnings:*** Net earnings from the Transmission business in 2001 were $585 million.

***Cost Savings:*** In 2001, TransCanada achieved approximately $65 million of pre-tax operating cost savings on the wholly-owned pipelines.

***Alberta System Settlement:*** The Alberta System settlement provides TransCanada and its customers more operational and contractual flexibility than previously available.

***Canadian Mainline Settlement:*** In 2001, the National Energy Board (NEB) approved TransCanada's 2001 and 2002 Tolls and Tariff Application on its Canadian Mainline system. The settlement resolved all issues other than cost of capital that will be addressed at the Fair Return Application proceedings, with an NEB decision expected in mid-2002.

***North American Pipeline Ventures:*** In 2001, TransCanada purchased an additional 5.96 per cent interest in Iroquois Gas Transmission System (Iroquois) and an additional 11.88 per cent in Portland Natural Gas Transmission System (Portland), increasing TransCanada's total interest to 40.96 per cent and 33.29 per cent, respectively.

***Northern Development:*** The signing of a Memorandum of Understanding with nine other major American and Canadian pipeline companies in November 2001 reinforces TransCanada's commitment to bring Alaska North Slope natural gas to markets in Canada and the lower 48 states.

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

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| **Wholly-Owned Pipelines** | | | |
| Alberta System | 204 | 219 | 219 |
| Canadian Mainline | 274 | 281 | 285 |
| BC System | 5 | 6 | 6 |
| | 483 | 506 | 510 |
| **North American Pipeline Ventures** | | | |
| Great Lakes | 56 | 52 | 55 |
| TC PipeLines, LP | 15 | 11 | 7 |
| Iroquois | 16 | 13 | 12 |
| Portland | (1) | (2) | (1) |
| Foothills | 20 | 22 | 21 |
| Trans Québec & Maritimes | 8 | 8 | 10 |
| Tuscarora | | | |
| – earnings | – | 2 | 3 |
| – gain on sale | – | 7 | – |
| Northern Border | | | |
| – earnings | – | – | 13 |
| – gain on sale | – | – | 47 |
| Northern Development | (9) | (3) | – |
| Other | (3) | 7 | – |
| | 102 | 117 | 167 |
| Net earnings | 585 | 623 | 677 |

TransCanada's Transmission business is strategically positioned for growth within the northern tier of North America, including transmission of northern gas reserves. As the industry and business environment change, TransCanada will seek, through customer negotiations and regulatory proceedings, changes to TransCanada's regulatory business model combined with continued focus on operational excellence to maximize the value TransCanada delivers to its customers and shareholders.

In 2001, net earnings from the Transmission business were $585 million, compared to $623 million and $677 million in 2000 and 1999, respectively. Excluding the impact of the sale of TransCanada's investments in Northern Border in 1999 and Tuscarora Gas Transmission Company (Tuscarora) in 2000, net earnings in 2001 for Transmission are lower than prior years. The decrease is mainly due to the expiry at the end of 2000 of the Cost-efficiency Incentive Settlement (CEIS) on the Alberta System; a decline in the rate of return on common equity and a lower average investment base in 2001 on the Canadian Mainline; as well as higher costs related to the company's northern development activities.

For 1999, 2000, and 2001, certain operating, maintenance and administrative (OM&A) costs were subject to the Merger Costs and Benefits Agreement (MCBA). Under the terms of the MCBA, TransCanada's shippers and its shareholders shared approximately pre-tax $70 million in OM&A cost savings in 2000 relative to a baseline established as of January 1999. In 2001, TransCanada achieved an additional pre-tax $30 million of OM&A cost savings, the benefit of which was shared equally between TransCanada's shippers and shareholders under the MCBA.

A two-year incentive settlement covering 2001 and 2002 for determination of tolls and services was reached between TransCanada and its shippers on the Alberta System. This settlement was approved in May 2001. The Alberta System settlement is a significant step in 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.

On the Canadian Mainline, the NEB approved a two-year incentive settlement covering 2001 and 2002 in November 2001. The settlement addressed all components of the Canadian Mainline's cost of service, with the exception of the cost of capital. This two-year settlement provides the foundation for further discussions to ensure the Canadian Mainline continues to compete effectively for market demand and natural gas supplies. The cost of capital issue is subject to an NEB hearing proceeding.

**WHOLLY-OWNED PIPELINES – FINANCIAL REVIEW**

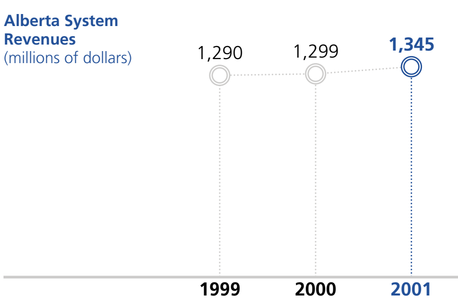
*Alberta System*

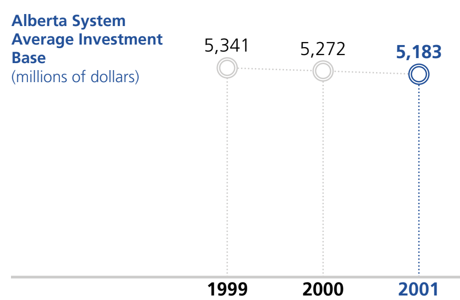
Net earnings of $204 million in 2001 are $15 million lower than in 2000 and 1999. Net earnings in 2001 reflect operating, financing and other cost savings, but are negatively impacted by a significantly lower implicit rate of return on equity in the Alberta System Rate Settlement (ASRS) compared to the CEIS. The CEIS expired at the end of 2000 and provided a fixed dollar equity return on a significant portion of the investment base. Under the ASRS, the majority of the Alberta System's revenue requirement for 2001 and 2002 is fixed at negotiated amounts of $1.390 billion and $1.347 billion, respectively. The MCBA includes a provision for the sharing of savings on most OM&A costs in 2001. As a result, in 2001, the Alberta System shared pre-tax operating cost savings of approximately $20 million equally with its customers.

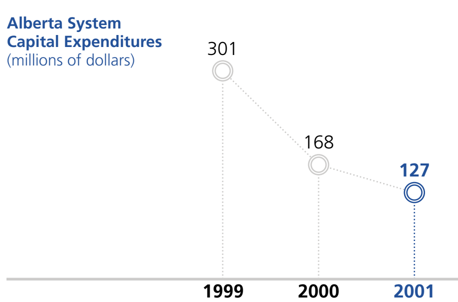
The Alberta System is one of the largest volume carriers of natural gas in North America and delivered 4,059 billion cubic feet (Bcf) of natural gas in 2001, as compared to deliveries of 4,490 Bcf in 2000 and 4,535 Bcf in 1999. The volumes transported by the Alberta System represent approximately 16 per cent of total North American natural gas production and about 65 per cent of the natural gas produced in the WCSB.

**ALBERTA SYSTEM**
TransCanada's 100 per cent owned natural gas transmission system in Alberta gathers natural gas for use within the province and delivers gas to provincial boundary points for connection with the Canadian Mainline, BC System and other pipelines. The 22,500 kilometre system is the largest carrier of natural gas in North America.

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.



**CANADIAN MAINLINE**

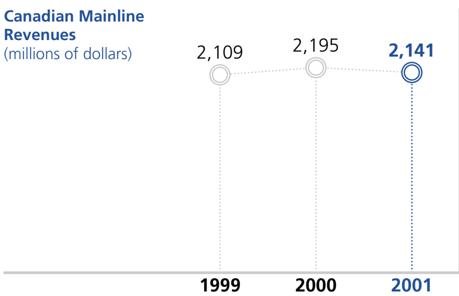
TransCanada's 100 per cent owned natural gas transmission system in Canada extends 14,900 kilometres from the Alberta/Saskatchewan border to the Québec/Vermont border and connects with other natural gas pipelines in Canada and the United States.

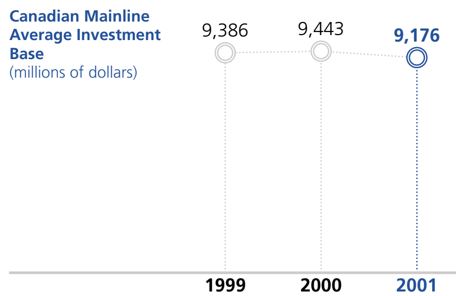
*Canadian Mainline*

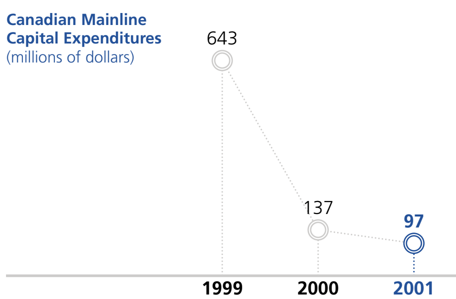
The Canadian Mainline generated net earnings of $274 million in 2001, a decrease of $7 million compared to 2000. The decrease in net earnings in 2001 as compared to 2000 is primarily due to a decline in the NEB approved rate of return on common equity, from 9.90 per cent in 2000 to 9.61 per cent in 2001, combined with a lower average investment base. This decrease is partially offset by the impact of incentive earnings realized in 2001 under the terms of the Mainline Service and Pricing Settlement (S&P Settlement). The 2001 net earnings are based on interim tolls approved by the NEB. Any adjustments to the interim tolls will be recorded in accordance with the NEB decision in the Fair Return Application proceedings.

Annual deliveries of natural gas on the Canadian Mainline totalled 2,450 Bcf in 2001, compared to deliveries of 2,675 Bcf in 2000 and 2,684 Bcf in 1999. In 2001, export deliveries comprised approximately 50 per cent of total deliveries, relatively unchanged from 2000 and 1999.

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, the return on common equity and incentive earnings affect the net earnings of the Canadian Mainline. In 2001, with the exception of incentive items implicit in the S&P Settlement, most of the operating and financing costs of the Canadian Mainline are recovered from customers.




**WHOLLY-OWNED PIPELINES – OUTLOOK**

TransCanada's wholly-owned natural gas pipelines are strategically positioned within the northern tier of North America. The strength of this business is derived from its ability to serve major North American gas markets, operating efficiency, capability to respond to requests for connection to new supply and markets, and the expertise of its people. This puts TransCanada in a unique position as the major transporter of Canadian gas both within the WCSB and across the continent.

In 2002, the Transmission business will continue to focus on achieving additional efficiency improvements in all aspects of the business, by continuing its focus on operational excellence and leveraging on technological advancements to further reduce the costs of operations for both TransCanada and its shippers. Transmission will also focus on continued negotiations for a new competitive business framework and discussions on possible changes in jurisdiction for parts of the Alberta System. A successful outcome of the Fair Return Application, related to cost of capital on the Canadian Mainline, would improve TransCanada's ability to ensure future competitiveness in the financial markets.

**BC SYSTEM**
TransCanada's 100 per cent owned natural gas transmission system extends 180 kilometres from Alberta's western border through British Columbia to the U.S. border, serving markets in British Columbia as well as the Pacific Northwest, California and Nevada.

*Earnings*

Net earnings for the Alberta System in 2002 are expected to be comparable to 2001, as the company continues to benefit from operating cost reductions. In addition, TransCanada's transitional support of pre-tax $6.25 million per quarter for the Alberta System's Products & Pricing Agreement ends in the first quarter of 2002.

Based on the terms of the S&P Settlement and excluding the outcome of the Fair Return Application proceedings which will determine the final tolls, net earnings from the Canadian Mainline are expected to decrease in 2002 compared to 2001. This is due primarily to a decrease in the NEB determined rate of return to 9.53 per cent from 9.61 per cent, combined with an expected decrease in average investment base.

*Capital Expenditures*

Total capital spending for the wholly-owned pipelines business during 2001 was $227 million. Capital spending in 2002 is expected to increase by approximately $150 million from 2001, due to projects required to increase transmission capacity on the Alberta and BC Systems, the largest of which is an expansion to service growing markets in California and the Pacific Northwest. As a result of excess pipeline capacity out of the WCSB, it is anticipated that overall capital expenditures will continue at lower than historical levels.

**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 processing plants in Alberta and then transporting that gas to two large mainline systems for domestic and export deliveries. The Alberta System is now facing competition from the Alliance Pipeline, a natural gas pipeline from northeast British Columbia to the Chicago area, which connects to some of the same gas plants. The maximum receipt capacity of the Alliance Pipeline is approximately 1.6 Bcf per day (Bcf/d) compared to TransCanada's Alberta System average 2001 receipt volumes of 11.4 Bcf/d. In 2001, in southern Alberta, one bypass pipeline was completed, which connects to the Canadian Mainline and has a capacity of 190 million cubic feet per day (MMcf/d).

The Canadian Mainline is TransCanada's cross-continent pipeline serving mid-western and eastern markets in Canada and the U.S. The demand for gas in TransCanada's key eastern markets is expected to continue to increase, particularly to meet the expected growth in gas-fired power generation. TransCanada does, however, face competition for its transportation services to eastern Canadian markets and U.S. export points. The main source of this competition is the combination of the newly constructed Alliance and Vector pipelines. In addition, TransCanada continues to face competition in its northeast U.S. markets where consumers can choose between additional U.S. supplies, offshore liquefied natural gas supplies and gas from the growing supply basin off Canada's east coast. New market growth customers and existing customers with expiring firm contracts may take advantage of these alternatives.

TransCanada's BC System is the link between the Alberta System and the PG&E Gas Transmission-Northwest pipeline to California. With increasing demand for natural gas in California, there are plans to expand this portion of TransCanada's wholly-owned pipeline system.

The Alliance and Vector pipelines went into service in late 2000. As a result of these new pipelines and lower than anticipated production from the WCSB, some firm capacity contracts on both the Alberta System and the Canadian Mainline have expired and not been renewed.

Over the past two years, the Alberta System has seen receipt contract non-renewals of 3.1 Bcf/d, or approximately 25 per cent of its 1998/99 firm contracted capacity. The Canadian Mainline was 100 per cent contracted with one year or longer firm contracts during the contract year 1998/99 and has since had 1.5 Bcf/d, or approximately 23 per cent of its capacity, non-renewed. Confirmed capacity for the 2000/01 contract year was at 77 per cent of total available capacity. As a result of a decrease in flow volumes due to the reduction in firm contracts, tolls on a per unit volume basis have increased on both the Alberta System and the Canadian Mainline, using the currently approved rate making methodologies. The toll increases due to contract non-renewals is somewhat mitigated by volumes flowed under interruptible contracts. As additional gas from the WCSB is transported to markets, utilization of the Alberta System is forecast to increase, which should cause the tolls to decrease. There is limited opportunity to reduce tolls on the Canadian Mainline due to expectations of continued spare capacity. The utilization of the Canadian Mainline is not expected to increase as additional supply from the WCSB is expected to be absorbed by demand growth within Western Canada and higher flows on other pipeline systems.

As a result, TransCanada is now operating in a new business environment that includes significant new risks of competition. During 2001, the Transmission business responded to increased competition by focusing on two main areas. The first area of focus was to further its proposals for a new competitive business and regulatory framework that will allow the business to better meet customer needs over the long term. TransCanada received approval from the EUB for the two-year ASRS incentive agreement between TransCanada and its shippers for the Alberta System. As well, the company completed negotiations and received approval from the NEB for the S&P Settlement between TransCanada and its Canadian Mainline customers. These agreements with industry partners represent a significant step within an evolutionary process to develop a new regulatory framework in Canada.

An application for a new business model will be filed with the NEB in the fall of 2002. This new business model is expected to allow for the continued recovery of capital costs while providing an incentive to reduce costs overall. Regardless of the outcome of the regulatory reform effort, TransCanada will continue to improve its operational excellence program to provide the most efficient pipeline service possible.

The second area of focus has been to work with its customers in ensuring timely connection of new supply areas to TransCanada's facilities and expansion of the facilities to markets where demand warrants. For example, by offering timely access for gas from the Ladyfern area in northwest Alberta, customers were able to take advantage of premium gas price environments. As well, proposed expansions of the Alberta and BC Systems into the Alberta industrial and U.S. Northwest gas markets will offer shippers greater access to market.

***Incentive Agreements***

TransCanada successfully negotiated with its Alberta System customers a two-year incentive agreement, the ASRS, which was approved by the EUB in May 2001. The ASRS provides for a fixed revenue requirement of $1.390 billion and $1.347 billion, to be recovered through tolls for the years 2001 and 2002, respectively. This fixed revenue requirement may be adjusted during the following year to account for:

- variances in firm service volumes;
- non-firm service revenue;
- variances in pipeline integrity spending;
- annual amortization of foreign exchange losses/gains on long-term debt principal; and
- changes in federal and provincial income tax rates.

Other major features of the ASRS include:

- an increase in the composite depreciation rate from 3.5 per cent to 4.0 per cent;
- the introduction of two new services – a point-to-point firm service and a one-year non-renewable receipt firm service;
- amortization of severance costs over four years;
- the introduction of a reserve account to allow for recovery of foreign exchange gains or losses on long-term debt principal; and
- the provision of an incentive to reduce costs through a continued focus on operational excellence.

Further, there is a commitment by parties to the ASRS to engage in future discussions to resolve rate and services issues.

During 2001, TransCanada filed two applications with the NEB requesting (a) approval of the Canadian Mainline S&P Settlement; and (b) approval of a change to the cost of capital for 2001 and 2002.

In May 2001, TransCanada filed its 2001 and 2002 Tolls and Tariff Application based on the terms of the S&P Settlement. The S&P Settlement, which received significant support from shippers, is essentially a cost of service tolling methodology, with the exception of the incentive earnings associated with the Revenue/Asset Management Program and other incentive mechanisms including OM&A costs, Fuel Gas Incentive Program, Foreign Exchange and Interest Rate Management Program, and Severance Program. The term of the S&P Settlement is 2001 and 2002. The S&P Settlement covers all components of the Canadian Mainline's revenue requirement, with the exception of the cost of capital. At the time of approval of the S&P Settlement in November 2001, the NEB also directed TransCanada to continue with its interim tolls pending the NEB's final decision on the cost of capital in the Fair Return Application proceedings.

In June 2001, TransCanada filed its Fair Return Application with the NEB. The application addresses the company's proposed changes to the cost of capital and requests a departure from the NEB's formula for determining the rate of return on common equity that was established in 1995. The company is seeking approval of an after-tax weighted average cost of capital (ATWACC) of 7.5 per cent effective January 1, 2001. This compares to an ATWACC of 5.84 per cent based on the 2001 return on equity under the current NEB formula. Final tolls for 2001 will be established following the NEB's decision which is expected in mid-2002.

***Safety***

TransCanada continues to work closely with its regulators, customers and communities to maintain safe operation of all of its facilities. Pipeline integrity expenditures are anticipated to decline to approximately $80 million in 2002 in response to positive testing results from the 2001 program and application of a rigorous risk management system. In response to recent heightened attention to the security of North American energy transportation infrastructure, TransCanada is working closely with industry associations and government agencies in Canada and the U.S. to maintain high levels of system security across the industry.

***Gas Supply***

Based on year-end 2000 estimates, the WCSB had remaining discovered reserves of 61 trillion cubic feet (Tcf) and a reserves-to-production ratio of approximately 10 years at current levels of production. Additional reserves are continually being discovered to maintain the reserves-to-production ratio at close to 10 years. Gas prices in the future are expected to be higher than historical averages due to a tighter supply/demand balance. TransCanada expects that high gas prices could result in continued modest growth in WCSB supply as producers increase their focus on deeper, more productive areas of the basin.

**GREAT LAKES**

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

**NORTHERN BORDER**

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

**IROQUOIS**

Iroquois connects with the Canadian Mainline and delivers natural gas to customers in the northeastern U.S. TransCanada increased its interest in this 604 kilometre pipeline to 40.96 per cent in 2001.

### NORTH AMERICAN PIPELINE VENTURES – FINANCIAL REVIEW

North American Pipeline Ventures (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.

TransCanada's proportionate share of net income from NAPV was $102 million in 2001, a decrease of $15 million compared to 2000, which included a one-time gain of $7 million from the sale of a 49 per cent interest in Tuscarora to TC PipeLines, LP. Excluding this gain on asset sale in 2000, NAPV's 2001 net earnings decreased $8 million when compared to the prior year. This decrease is primarily due to increased costs related to TransCanada's northern development activities in 2001. In addition, pipeline business development costs were higher in 2001 as a result of increased activity levels.

NAPV's 2000 net earnings of $117 million were relatively unchanged from 1999, excluding the $47 million after-tax gain on the sale of Northern Border to TC PipeLines, LP in 1999.

### NORTH AMERICAN PIPELINE VENTURES – OUTLOOK

TransCanada actively continues to pursue gas pipeline development and acquisition opportunities in Canada and the northern tier of the U.S., where these opportunities are driven by strong customer demand and sound economics.

***TC PipeLines, LP***

TransCanada holds a 33.4 per cent interest in TC PipeLines, LP, a publicly-held limited partnership. It was formed to acquire, own and participate in the management of U.S.-based pipeline investments. It is managed by TransCanada and holds a 30 per cent interest in Northern Border and a 49 per cent interest in Tuscarora. In July 2001, TC PipeLines, LP increased its quarterly distribution from US$0.475 per unit to US$0.50 per unit. This represents the second increase in the partnership's quarterly cash distribution since the commencement of operations in May 1999.

In October 2001, Northern Border completed construction of Project 2000 which consisted of a 55 kilometre pipeline extension providing 545 MMcf/d of incremental transportation capacity to North Hayden, Indiana. In addition, Northern Border's delivery capability into the Chicago area has been expanded by approximately 30 per cent due to Project 2000.

In January 2002, the U.S. Federal Energy Regulatory Commission (FERC) issued a final certificate approving Tuscarora's proposed expansion which would enable the company to meet new service requests. The proposed expansion consists of three compressor stations and a 23 kilometre pipeline extension that will provide approximately 93 MMcf/d of incremental transportation capacity at an estimated cost of US$60 million. The expansion is expected to commence commercial operations in late 2002.

***Iroquois Eastchester Expansion***

In December 2001, Iroquois received final FERC approval to construct the US$210 million Eastchester Expansion project. Construction on this project, which will extend Iroquois' system from Long Island into the New York city market, is scheduled to begin in the spring of 2002. Full service is expected to commence by March 2003 and will provide an additional 230 MMcf/d of new service into this market.

### *Other Iroquois Expansion Projects*

Three applications were filed with the FERC in the fourth quarter of 2001, which if approved would see total capital additions of US$148 million to the pipeline system occurring between 2003 and 2005.

### *Iroquois/Portland Ownership Changes*

In May 2001, TransCanada purchased an additional 5.96 per cent interest in Iroquois, bringing its total interest to 40.96 per cent. In June 2001, TransCanada purchased an additional 11.88 per cent interest in Portland, bringing its total interest to 33.29 per cent. TransCanada holds the largest ownership interest in both Iroquois and Portland.

### *Portland Rate Application*

Portland filed a Rate Application with the FERC in October 2001. Portland will be operating under a FERC approved interim toll commencing April 1, 2002, until a final toll is determined.

### *Northern Development*

TransCanada actively continues to pursue pipeline opportunities to move both Mackenzie Delta and Alaska North Slope natural gas to markets throughout North America. TransCanada worked with key stakeholders in 2001 to promote a stand-alone Mackenzie Valley pipeline project. The Mackenzie Delta producers have indicated they would prefer to use TransCanada's existing Alberta System for gas to be transported to markets.

In November 2001, TransCanada was one of ten companies, known as the ANGTS Group, to sign a Memorandum of Understanding to begin developing an initial commercial transportation proposal relating to northern slope gas production in Alaska. The group is pursuing development of the Alaska Natural Gas Transportation System, also known as the Alaska Highway project. The ANGTS Group completed the initial proposal in 2001 and is discussing details on this complex project and potential commercial arrangements with Alaska North Slope producers.

TransCanada spent considerable time in 2001 gathering input from producers with natural gas reserves in the WCSB and the two Arctic basins on options for moving northern gas once it reaches Alberta. As a result of these discussions, TransCanada has developed a comprehensive plan that provides flexibility and choice for all producers to move their natural gas. This plan ensures costs are effectively managed by using existing infrastructure where possible and by expanding in increments based on the volumes to be shipped. The company continues to refine and discuss this plan.

All costs incurred to date related to northern development have been expensed as incurred.

### *Northwinds Pipeline*

In September 2001, TransCanada and National Fuel Gas Supply Corporation announced the formation of a strategic partnership to evaluate the feasibility of developing a new natural gas pipeline project (Northwinds Pipeline) to provide transportation service from Dawn, Ontario to the Ellisburg-Leidy area in Pennsylvania. The partnership is currently evaluating market support for the project.

**TUSCARORA**

Tuscarora operates a 369 kilometre pipeline system transporting gas from Malin, Oregon to Reno, Nevada with delivery points in north-eastern California. TransCanada owns an aggregate 17.4 per cent interest in Tuscarora, of which 16.4 per cent is held through TransCanada's interest in TC PipeLines, LP.

**PORTLAND**

Portland operates a 471 kilometre pipeline which connects with TQM near Pittsburgh, New Hampshire and has delivery points in Massachusetts. TransCanada increased its interest in Portland to 33.29 per cent in 2001.

**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 50 per cent of Foothills, 69.5 per cent of Foothills (Sask.), 74.5 per cent of Foothills (Alta.) and 74.5 per cent of Foothills (South B.C.). Together, these pipelines systems total 1,040 kilometres in length.

**TQM**

Trans Québec & Maritimes Pipeline Inc. (TQM) is a 572 kilometre natural gas pipeline system which connects with the Canadian Mainline and transports gas from Montreal to Québec City and to the Portland system. TransCanada holds a 50 per cent interest in TQM.

**VENTURES LP**

Ventures LP, 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.

### *Millennium Pipeline*

TransCanada has a 21 per cent interest in the proposed Millennium Pipeline project in the U.S. and 100 per cent of the Canadian portion of the Lake Erie crossing. In August 2001, TransCanada and Westcoast Energy jointly withdrew their respective NEB applications and in December 2001, the Minister of the Environment for Canada terminated the environmental assessment of the Canadian Millennium project.

### *Ventures LP*

In 2001, TransCanada Pipeline Ventures Limited Partnership (Ventures LP) was successful in securing incremental contracts for transportation service on its oilsands pipeline in northeast Alberta. To support this new service, planning and construction activities are underway on a lateral pipeline expansion and a compressor station addition. These projects are expected to be placed in service in 2002 and 2003.

**NATURAL GAS THROUGHPUT VOLUMES**

(Bcf)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| Alberta System | 4,059 | 4,490 | 4,535 |
| Canadian Mainline | 2,450 | 2,675 | 2,684 |
| BC System | 395 | 408 | 398 |
| Great Lakes | 804 | 898 | 937 |
| Northern Border | 821 | 853 | 835 |
| Iroquois | 314 | 344 | 345 |
| Portland* | 44 | 40 | 22 |
| Tuscarora | 23 | 25 | 24 |
| Foothills | 1,117 | 1,186 | 1,132 |
| Trans Québec & Maritimes | 161 | 168 | 147 |
| Ventures LP* | 60 | 36 | – |

*Placed in service in 1999.

## POWER

### HIGHLIGHTS

***Earnings Increase:*** $75 million or 91 per cent increase in net earnings before asset sales in 2001 compared to 2000; $43 million or 79 per cent average increase in annual net earnings over the past three years.

***Plant Growth:*** Added electrical supply totalling more than 650 megawatts (MW) in 2001; added 11 new plants totalling more than 1,500 MW over the past three years.

***Operations Growth:*** 67 per cent increase in volumes sold in 2001 compared to 2000; 37 per cent average increase in annual volumes sold over the past three years.

***Operational Excellence:*** 96 per cent average plant availability in 2001; 96 per cent average plant availability over past three years.

**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.

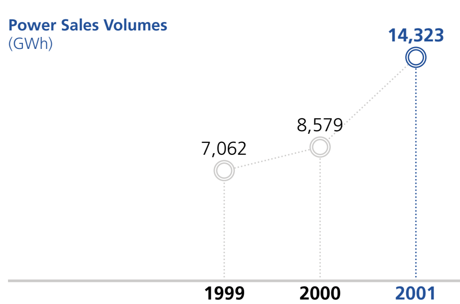
**POWER RESULTS-AT-A-GLANCE**

**Year ended December 31** (millions of dollars)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| Northeastern U.S. operations | 159 | 68 | 53 |
| Western operations | 132 | 71 | 20 |
| Power LP investment | 39 | 33 | 26 |
| General, administrative and support costs | (49) | (21) | (23) |
| Operating and other income | 281 | 151 | 76 |
| Financial charges | (24) | (15) | (13) |
| Income taxes | (100) | (54) | (23) |
| | 157 | 82 | 40 |
| After-tax gain on sale of Hermiston Power Partnership | – | 23 | – |
| Net earnings | 157 | 105 | 40 |

TransCanada's Power business contributed $157 million of net earnings in 2001, representing an increase of $75 million or 91 per cent compared to net earnings before asset sales of $82 million in 2000. This increase is primarily attributable to increased earnings in each of Power's business lines:

- *Northeastern U.S. Operations:* Increased marketing activities; capitalized on price volatility and market opportunities in 2001; increased ownership to 100 per cent in Ocean State Power (OSP) plant in October 2000; and acquisition of the Curtis Palmer facility in July 2001.
- *Western Operations:* Successfully commenced transactions under the Sundance A power purchase arrangement (PPA); and capitalized on high prices and market volatility, especially in the first half of 2001.
- *Power LP Investment:* Higher average ownership in TransCanada Power, L.P. (Power LP) in 2001 compared to 2000 and strong plant performance.



The increase in general, administrative and support costs in 2001 reflects the increased activity in TransCanada's Power business, as well as the company's focus on future growth in this segment.

Power's net earnings of $105 million in 2000 increased by $65 million compared to 1999. This increase included a $23 million after-tax gain on the sale of TransCanada's interest in the Hermiston Power Partnership in 2000, and reflected higher marketing and trading earnings; the acquisition of the remaining 29.9 per cent ownership interest in Ocean State in October 2000; and increased ownership interest and strong plant performance in the Power LP.

Higher revenues and operating expenses in the Power segment reflect higher power prices, the addition of new facilities, and increased commercial activity in 2001 when compared to 2000 and 1999.

**NOMINAL GENERATING CAPACITY OF POWER PLANTS (MW)**

| | |
|---|---|
| TransCanada Power | |
| Ocean State | 560 |
| MacKay River[1] | 165 |
| Carseland | 80 |
| Bear Creek[1] | 80 |
| Curtis Palmer | 60 |
| Redwater | 40 |
| Cancarb | 27 |
| | |
| Power LP[2] | |
| Williams Lake | 66 |
| Castleton | 64 |
| Tunis | 43 |
| Kapuskasing | 40 |
| Nipigon | 40 |
| North Bay | 40 |
| Calstock | 35 |
| | |
| Other[3] | |
| Sundance A | 560 |
| Sundance B | 353 |
| | 2,253 |

[1] Currently under construction.
[2] At December 31, 2001, TransCanada held a 35.6 per cent ownership interest in Power LP.
[3] TransCanada buys 560 MW of the Sundance A and 353 MW of the Sundance B power plant output through long-term PPAs.

**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.

**NORTHEASTERN U.S. OPERATIONS**

Northeastern U.S. Operations includes the 560 MW gas-fired OSP plant, the output from the 64 MW gas-fired Castleton power plant, the 60 MW Curtis Palmer hydroelectric power plant and the Westborough, Massachusetts power marketing office (TCPM). TCPM markets electricity to a variety of customers throughout the northeastern U.S., both directly and through distribution re-sellers.

The Northeastern U.S. Operations' operating income in 2001 increased $91 million or 134 per cent compared to 2000. This was primarily due to the ability to capitalize on unprecedented price volatility throughout 2001 and significantly increased commercial activity of TCPM in 2001. Through prudent use of physical plant to backstop its marketing activities, supplemented with additional contract supplies and markets, TCPM was able to optimize its assets and capture market opportunities through this volatile period. TCPM sells the majority of the output from the northeastern plants under long-term arrangements, although continued supply flexibility is fundamental to Power's growth and success in the deregulated New England and New York markets. In addition, TCPM expanded its marketing efforts and increased its earnings in 2001 by successfully providing electricity supply services to a variety of direct industrial and wholesale customers, which added incremental business to its portfolio without taking significant price risk.

The $15 million or 28 per cent increase in operating income from 1999 to 2000 was primarily due to the acquisition of the remaining 29.9 per cent equity interest in OSP in October 2000. The OSP facility remains under FERC regulation and earns a regulated rate of return.

In July 2001, Power expanded its Northeastern U.S. Operations through the acquisition of the Curtis Palmer Hydroelectric Company, L.P. The purchase of the Curtis Palmer facility near Corinth, New York represents TransCanada's first hydroelectric facility and a further diversification of Power's fuel sources. The plant has a generating capacity of 60 MW, all of which is sold under a fixed-priced, long-term agreement to Niagara Mohawk Power Corporation with a remaining term of more than 25 years. In December 2001, TransCanada completed an upgrade of the water control facilities at Curtis Palmer.

**WESTERN OPERATIONS**

Western Operations has two main components – Western Marketing and Plant Operations. Western Marketing includes the power marketing and trading operations originating out of the Calgary office, including the purchase of electricity under the 560 MW Sundance A PPA, commencing January 1, 2001, and the subsequent resale of this output to industrial and marketing customers. From its Calgary office, TransCanada markets electricity across Canada and throughout the northern tier of the U.S. from Washington to Wisconsin. Plant Operations includes contributions from TransCanada's Alberta power plants as well as fees earned to manage Power LP and operate its seven plants.

Western Operations had a significant increase of $61 million or 86 per cent in operating income in 2001 compared to 2000, primarily due to the acquisition of the 560 MW Sundance A PPA in 2000 and increased commercial activity that capitalized on opportunities created by price volatility in Western Canada and the Pacific Northwest regions.

The increase of $51 million or 255 per cent in operating income from 1999 to 2000 was due to higher marketing earnings from increased sales in Alberta and capitalizing on opportunities created by extreme price volatility in the Western Region.

***Western Marketing***

The deregulation of the Alberta power market provided TransCanada with the opportunity to acquire new long-term and short-term supply sources through the Sundance A PPA and the Market Achievement Plan auction, which occurred in August and December 2000, respectively. Under the Sundance A PPA, TransCanada acquired 560 MW of coal-fired baseload supply in Alberta for a 17-year period. TransCanada commenced transactions under this PPA beginning January 1, 2001. Through a partnership with AltaGas Services Inc., in December 2001, TransCanada effectively acquired 50 per cent of the remaining rights and obligations of the 706 MW Sundance B PPA. TransCanada will use its experience and expertise from Sundance A to optimize the earnings from Sundance B. The Sundance B PPA acquisition will provide TransCanada with an additional 353 MW of supply for the next 19 years and is expected to immediately begin contributing incremental earnings commencing January 2002. TransCanada has sold all of its Sundance A and B power supply in 2002 and 59 per cent of its expected, average combined Sundance A and B power supply for the next five years. TransCanada continues to secure additional long-term sales contracts for the remaining Sundance A and B power supply as well as any uncontracted supply from its Alberta power plants.

In 2001, in addition to the sales of Sundance A output, TransCanada utilized its marketing experience to successfully take advantage of market opportunities created by high market prices, power price volatility and inefficiencies

**WILLIAMS LAKE**

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

**OCEAN STATE**

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

**BEAR CREEK & MACKAY RIVER**

Currently under construction are the 165 MW MacKay River facility near Fort McMurray, Alberta and the 80 MW Bear Creek facility near Grande Prairie, Alberta. The expected completion dates are 2003 for MacKay River and late 2002 for Bear Creek.

**CARSELAND**

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

**REDWATER**

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

**CANCARB**

The 27 MW Cancarb facility began full commercial operation in January 2001. The Cancarb power plant is fuelled by waste heat from the adjacent thermal carbon black facility.

**CURTIS PALMER**

In July 2001, TransCanada acquired the 60 MW Curtis Palmer facility near Corinth, New York, which represents the company's first hydroelectric facility. All output from this facility is sold through a fixed-priced, long-term agreement.

between market regions. The ability to trade electricity in the spot market is critical to capitalizing on market opportunities as they arise and is fundamental to managing a portfolio of power assets and long-term supply contracts efficiently.

***Plant Operations***

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

TransCanada again proved to be a successful power plant operator in 2001 as evidenced by the 96 per cent average plant availability across all operating plants in the year. TransCanada will apply this same commitment to operational excellence at the two new Alberta plants commissioned in late 2001, being the 40 MW Redwater and the 80 MW Carseland power plants. These plants are the result of a strategic power development model that meets the long-term desires of both TransCanada and its customers. Under this model, TransCanada is able to expand its portfolio of power plants while avoiding excessive price risk through the use of long-term sales contracts to industrial customers for a significant portion of the plant output while, at the same time, retaining a certain amount of merchant capacity. In addition, because these plants generate electricity and steam, the industrial customers obtain a long-term, dependable supply of both electricity and steam/heat for use at their adjacent facility or other facilities in the region.

The success of this model led to the announcement of construction of two new Alberta power plants in 2001. The Bear Creek plant, scheduled for completion in late 2002, will be an 80 MW cogeneration facility near Grande Prairie, Alberta and will sell power to Weyerhaeuser at its Grande Prairie Pulp Mill, as well as Weyerhaeuser's other Alberta facilities. The MacKay River plant, which is currently expected to be in commercial operation in 2003, will be a 165 MW cogeneration facility near Fort McMurray, Alberta and will provide electricity and steam to Petro-Canada's adjacent in-situ oil sands operations. Similar to the Redwater and Carseland plants, 100 per cent of the heat/steam output and a significant portion of the electricity output from these plants will be sold to industrial customers on a long-term basis. The Bear Creek project was one of the proposals selected by the Province of Alberta's Transmission Administrator, ESBI Alberta Ltd., under the "Location-Based Credits Standing Offer" process to attract new power generation to the Grande Prairie area to resolve transmission constraints in the area's transmission system. Upon expected completion in 2003, the MacKay River plant will be TransCanada's largest power plant in Alberta, and will increase TransCanada's directly controlled output in the province to more than 1,300 MW.

In 2001, TransCanada successfully began full commercial operation of its Cancarb power plant, which is adjacent to TransCanada's thermal carbon black manufacturing facility. The facility is similar to TransCanada's other Alberta cogeneration facilities, except both the power plant and the industrial host are TransCanada's businesses. The power plant produces electricity, which is sold under a long-term contract to the City of Medicine Hat, and is 100 per cent fuelled by waste heat from the Cancarb facility.

**POWER LP**

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

Operating income from TransCanada's investment in Power LP increased $6 million or 18 per cent compared to 2000 as a result of an increased ownership interest throughout the majority of 2001 compared to 2000. In exchange for construction of the Calstock plant, TransCanada received 4.4 million Power LP units, which became eligible for distribution in October 2000 when the plant was completed and put into service. This increased

TransCanada's ownership interest in Power LP from 32.7 per cent to 41.6 per cent. In October 2001, Power LP issued approximately 5.7 million units in a public offering which decreased TransCanada's ownership interest from 41.6 per cent to 35.6 per cent. At December 31, 2001, the Power LP units closed at $31.75 on The Toronto Stock Exchange and TransCanada owned approximately 14.0 million units.

As noted, TransCanada provides management services to Power LP. This, combined with TransCanada's ownership share, has resulted in Power LP being a key asset in growing TransCanada's overall power business. Power LP has experienced continuous growth since its inception in mid-1997 and will continue with this focus into the future. As a result of this growth and the expectation of sustainable cashflow, Power LP increased its quarterly distributions from $0.60 per unit to $0.63 per unit in June 2001.

*Outlook*

Power represents TransCanada's greatest opportunity for growth in the near term and will continue to be a key growth area over the long term. TransCanada is committed to growing its power business through a continued, combined approach of acquisitions, greenfield developments and further expansions of its existing businesses and footprint in the North American electricity market. This growth will continue to be focused on the company's target markets within Canada and the northern tier of the U.S. It will be undertaken by thoroughly understanding the market fundamentals in the market regions, capitalizing on opportunities as they arise and managing risks in the same manner that resulted in Power's strong success to date.

TransCanada will continue the growth of the power business in 2002 and beyond. TransCanada will continue to capitalize on opportunities presented by deregulation and other market forces as well as growth through the addition of new power supplies. Power will continue its pursuit of operational excellence as new plants are added. Expansion of the Northeastern U.S. Operations and Western Operations will continue with a balanced portfolio of short-term trading around existing operations and new opportunities combined with medium- to long-term sales to industrial customers. Power will explore additional acquisition opportunities of various sizes in target markets that are consistent with its strategy. With proven success in the Alberta and New England deregulated markets, TransCanada will be able to build on these experiences and use them to capture opportunities presented by the pending deregulation in the Ontario market expected in the first half of 2002. Power will also pursue new marketing opportunities and seek acquisition opportunities directly or through Power LP.

**BUSINESS RISKS**

*Plant Availability*

Maintaining plant availability is critical to Power's continued success, and this risk is mitigated through a commitment to excellent operating performance at each of its power plants. This same commitment will be applied in 2002 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 and fluctuating supply and demand which are greatly affected by weather, consumer usage and plant availability. These inherent market risks are managed through the use of long-term purchase and sales contracts for both electricity and plant fuels; control over generation output; matching physical plant contracts or PPA supply with customer demand; fee-for-service managed accounts rather than direct commodity exposure; and TransCanada's overall risk management program with respect to general market and counterparty risks. The company's risk management practices are described in the section on Risk Management and in Note 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.

## CORPORATE

### HIGHLIGHTS

***Lower Net Expenses:*** Excluding tax rate changes, net expenses decreased by $34 million or 32 per cent from 2000.

***Reduced Financial Charges:*** The company reduced its long-term debt by $793 million and redeemed preferred securities of $318 million in 2001, resulting in reduced financial charges.

***Cost Reductions:*** In 2001, the company continued to reduce general and administrative costs.

### CORPORATE RESULTS-AT-A-GLANCE

**Year ended December 31** (millions of dollars)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| General and administrative costs related to discontinued operations | 13 | 18 | 19 |
| Indirect financial and preferred equity charges | 67 | 109 | 158 |
| Interest income and other | (13) | (49) | (22) |
| | 67 | 78 | 155 |
| Restructuring and other costs | 5 | – | 108 |
| Net expenses, after tax | 72 | 78 | 263 |

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

- *General and administrative costs relating to services that support discontinued operations:* Corporate overhead costs related to discontinued operations remain in the Corporate segment.
- *Indirect financial and preferred equity charges:* Direct financial charges are reported in their respective business segments and are primarily associated with the debt and preferred securities related to the wholly-owned pipelines.
- *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, rationalization of real estate and other provisions, as well as asset impairments. In 2001, TransCanada recorded a $5 million after-tax adjustment to these costs.

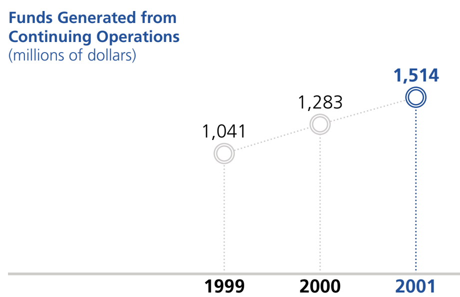
Net expenses, after tax, in the Corporate segment, excluding restructuring and other costs, were $67 million in 2001 compared to $78 million in 2000 and $155 million in 1999. The decrease in 2001 over 2000 is primarily due to lower financial and preferred equity charges as a result of lower net debt balances and the redemption of preferred securities. In addition, tax recoveries of $28 million were recorded in 2000 to reflect the impact of tax law and income tax rate changes. The decrease in 2000 over 1999 is also due to lower financial and preferred equity charges. Financial charges in 2001 reflect a full year's impact of the 2000 debt reductions as well as additional debt reductions in 2001.

## LIQUIDITY AND CAPITAL RESOURCES

### *Funds Generated from Operations*

Funds generated from continuing operations were $1.514 billion for the year ended December 31, 2001 compared with $1.283 billion and $1.041 billion for 2000 and 1999, respectively. The Transmission business was the primary source of funds generated from operations for each of the three years.

The company has decreased long-term debt and preferred securities in 2000 and 2001 and increased funds generated from operations over the same period. TransCanada's ability to generate adequate amounts of cash in the short term and the long term when needed, and to maintain financial capacity and flexibility to provide for future growth, was stronger at December 31, 2001 than in the past few years.




### *Investing Activities*

Capital expenditures, excluding acquisitions, totalled $492 million in 2001, a decrease of $320 million compared to 2000. Expenditures in both 2001 and 2000 relate primarily to maintenance and capacity capital in TransCanada's Transmission business and construction of new power plants in Alberta. The majority of the 1999 capital spending of approximately $1.8 billion related to the expansion of the wholly-owned pipelines and expenditures in discontinued operations.

During 2001, TransCanada acquired the Curtis Palmer Hydroelectric Company, L.P. from International Paper Company for $438 million. TransCanada's 2001 and 2000 investing activities also include proceeds of $1.17 billion and $2.23 billion, respectively, from the sale of non-core assets under the company's divestiture plans. TransCanada's 1999 investing activities also include proceeds of $658 million from the disposition of non-core assets.

### *Financing Activities*

In 2001, TransCanada used a portion of its cash resources to fund repayment of long-term debt of $793 million and to redeem preferred securities of $318 million. In 2000, TransCanada used proceeds on disposition of assets, together with cash flow from operations, to repurchase or redeem approximately $2.5 billion in long-term debt and preferred shares. Dividends and preferred securities charges amounting to $517 million were paid in 2001 compared to $536 million and $664 million in 2000 and 1999, respectively.

In January 2002, TransCanada's Board of Directors approved an increase in the quarterly common share dividend payment from $0.225 per share to $0.25 per share for the quarter ended March 31, 2002; in January 2001, TransCanada's Board of Directors approved an increase from $0.20 per share to $0.225 per share for the quarter ended March 31, 2001.

Net cash used in financing activities includes TransCanada's proportionate share of the net reduction in non-recourse debt of joint ventures amounting to $109 million in 2001, reflecting non-recourse debt repaid during the year offset partially by new debt issued. Net cash provided by non-recourse joint venture debt activities was $122 million in 2000 compared to $13 million in 1999.

### *Credit Activities*

Unused lines of credit of $1.8 billion were available to support TransCanada's commercial paper program and for general corporate purposes at December 31, 2001. At December 31, 2001, the company had used approximately $100 million of its lines of credit for letters of credit utilized to support its ongoing commercial arrangements. At December 31, 2001, US$750 million of medium-term notes could be issued under TransCanada's medium-term note program in the U.S.

### *Obligations and Commitments*

Total long-term debt at December 31, 2001 was $9.830 billion compared to $10.540 billion at December 31, 2000. Total non-recourse debt of joint ventures at December 31, 2001 was $1.339 billion, relatively unchanged from $1.325 billion in the prior year. Total notes payable, including those of joint ventures, at December 31, 2001 were $343 million compared to $200 million at December 31, 2000. The debt and notes payable of joint ventures are non-recourse to TransCanada. The security provided by each joint venture is limited to the rights and assets of that joint venture and does not extend to the rights and assets of TransCanada, except to the extent of TransCanada's investment.

At December 31, 2001, mandatory retirements resulting from maturities and sinking fund obligations related to long-term debt and the company's proportionate share of the non-recourse debt of joint ventures are as follows.

**MANDATORY RETIREMENTS**
**December 31** (millions of dollars)

| | 2002 | 2003 | 2004 | 2005 | 2006 | 2007+ |
|---|---|---|---|---|---|---|
| Long-term debt | 483 | 550 | 370 | 358 | 503 | 7,566 |
| Non-recourse debt of joint ventures | 44 | 231 | 38 | 339 | 26 | 661 |

TransCanada has no significant operating leases at December 31, 2001. The company had no outstanding guarantees related to the long-term debt of unrelated third parties at December 31, 2001. TransCanada and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business.

TransCanada has guaranteed the equity undertaking of a subsidiary which supports the payment of debt obligations of TransGas de Occidente, S.A. (TransGas), in the event a change of law would result in insufficient funds in TransGas to pay the interest and principal on its public US$240 million debt obligations. The company has an indirect 46.5 per cent interest in TransGas. Under the terms of the agreement, the company and another major multinational company, may be required to fund more than their proportionate share of debt obligations of TransGas in the event that the minority shareholders fail to contribute. Any payments made by TransCanada under this agreement convert into shares of TransGas. The potential exposure is contingent on the impact of any change of law on TransGas' ability to service the debt. From the issuance of the debt in 1995 to date, there has been no change in applicable law and thus no exposure to TransCanada. The debt matures in 2010.

At December 31, 2001, TransCanada held a 35.6 per cent interest in Power LP which is a publicly-held limited partnership. On June 30, 2017, the partnership will redeem all units outstanding, not held directly or indirectly by TransCanada, at their then fair market value, being the average of the fair market values assigned thereto by independent valuators, plus all declared and unpaid distributions of distributable cash thereon (the Redemption Price). The Redemption Price will be satisfied by TransCanada in cash or, at the election of TransCanada, in common shares of TransCanada or a combination of cash and common shares.

TransCanada has granted a $50 million operating line of credit to Power LP. As at December 31, 2001, the amount borrowed against this line of credit was $15.9 million compared to $4.0 million at December 31, 2000.

At December 31, 2001, TransCanada held a 33.4 per cent interest in TC PipeLines, LP which is a publicly-held limited partnership. On May 28, 2001, TC PipeLines, LP renewed its $40 million unsecured two-year revolving credit facility (TransCanada Credit Facility) with a subsidiary of TransCanada. At December 31, 2001 and 2000, the partnership had no amount outstanding under the TransCanada Credit Facility.

## RISK MANAGEMENT

TransCanada manages market risk exposures in accordance with its corporate market risk policy and position limits. The company's primary market risks result from volatility in commodity prices, interest rates and foreign currency exchange rates. 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.

### *Power Marketing Price Risk Management*

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

The net asset mark-to-market position of power energy trading contracts at December 31, 2001 was $333 million, comprised of $314 million related to the company's initial payments for the Sundance A and B PPAs and supported by updated discounted cash flow analysis, and $19 million of other trading activities. The net asset mark-to-market position for the other trading activities was determined using prices actively quoted and substantially all of the positions mature by December 31, 2002. The net asset mark-to-market position increased by $84 million in 2001, which includes the Sundance B PPA payment of $110 million.

### *Financial Risk Management*

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

The company's financial risk management practices are described under the Foreign Exchange and Interest Rate Management Activity in Note 12 to the Consolidated Financial Statements.

### *Counterparty Risk Management*

Counterparty risk entails a counterparty's ability to meet its obligations in a timely manner as outlined under the terms and conditions of its contracts. Counterparty risk is mitigated by conducting financial assessments to establish a counterparty's creditworthiness, setting exposure limits and monitoring exposures against these limits, and, where warranted, obtaining financial assurances.

The company's counterparty risk management practices and positions are described under Credit Risk in Note 12 to the Consolidated Financial Statements.

## CRITICAL ACCOUNTING POLICY

The company accounts for the impacts of rate regulation in accordance with generally accepted accounting principles (GAAP) as outlined in Note 1 to the Consolidated Financial Statements. Three criteria must be met to use these accounting principles: the rates for regulated services or activities must be subject to approval by a regulator; the regulated rates must be designed to recover the cost of providing the services or products; and it must be reasonable to assume that rates set at levels to recover the cost can be charged to and will be collected from customers in view of the demand for services or products and the level of direct and indirect competitition. Management believes that all three of these criteria have been met. The most significant impact of the use of these accounting principles is that in order to achieve a proper matching of revenues and expenses, the timing of recognition of certain expenses and revenues may differ from that otherwise expected under GAAP. The two most significant examples of this relate to the recording of income taxes on the taxes payable basis and the deferral of foreign exchange losses as outlined in the Consolidated Financial Statements' Note 13 and Note 7, respectively.

## ACCOUNTING CHANGES

### *Earnings Per Share*

Effective January 1, 2001, the company adopted the new standard of the Canadian Institute of Chartered Accountants (CICA) with respect to earnings per share. The new standard requires a new basis for calculating diluted earnings per share using the treasury stock method instead of the imputed earnings approach to determine the dilutive effects of warrants, options and equivalents. This accounting change was applied retroactively but did not significantly impact previously reported earnings per share.

### *Hedging Relationships*

In November 2001, the Accounting Standards Board of the CICA issued an Accounting Guideline "Hedging Relationships", that establishes standards for the documentation and effectiveness of hedging relationships. These standards are substantially similar to the corresponding requirements under Statement of Financial Accounting Standards (SFAS) No. 133 which was adopted by the company for U.S. GAAP purposes, effective January 1, 2001. The company does not expect the new Canadian requirement to have a significant impact on its financial statements.

### *Foreign Currency Translation*

In November 2001, an amendment to the CICA Handbook Section "Foreign Currency Translation", was issued and will be effective for the company as of January 1, 2002. The amendment eliminates the deferral and amortization of unrealized translation gains and losses on foreign currency denominated monetary items that have a fixed or ascertainable life extending beyond the end of the fiscal year following the current reporting period. The impact on the company's financial statements of implementing this amendment is not expected to be significant due to the company's regulatory accounting policies and hedging practices.

### *Stock-Based Compensation*

In November 2001, the CICA Handbook Section "Stock-Based Compensation and Other Stock-Based Payments", was issued and will be effective for the company as of January 1, 2002. This section is consistent with SFAS No. 123 which was adopted by the company for U.S. GAAP purposes. The impact on the company's financial statements of implementing this amendment is not expected to be significant.

## DISCONTINUED OPERATIONS

TransCanada has realized approximately $3.4 billion of proceeds from asset sales of all discontinued operations.

### FINANCIAL REVIEW

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

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

The company recorded a net loss from discontinued operations in 1999 of $534 million. This amount includes a net gain of $20 million related to the April Plan (which was substantially completed in 1999); and a net loss of $439 million, asset impairments of $159 million and earnings prior to plan approval of $54 million related to the December Plan; and a loss prior to plan approval of $10 million related to Gas Marketing.

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

The company recorded a net loss from discontinued operations in 2001 of $67 million. This amount includes a net loss of $90 million based on management's estimates of proceeds and disposal costs and net earnings of $3 million prior to plan approval, related to the Gas Marketing business. Also included in 2001 is a positive $20 million after-tax adjustment to the December Plan, which was substantially completed at December 31, 2001. 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.

The company's exit from Gas Marketing was substantially completed at December 31, 2001. TransCanada remains contingently liable pursuant to obligations under certain contracts that relate to the divested Gas Marketing business. The company has deferred recognition of after-tax gains on sales in the amount of approximately $100 million and has included this in the December 31, 2001 balance sheet provision for loss on discontinued operations. The gains will be recognized in income from discontinued operations as the underlying exposures reduce. In accordance with the terms of these contracts and in the normal course of business, the underlying volumes related to the contracts are expected to decrease over time, with the majority expected to decrease in 2002. The contingent liability under these obligations, which could be significant, is contingent on certain future events, the occurrence of which is not determinable, and the amount, if any, is dependent upon future prevailing market prices and conditions. The purchasers of the Gas Marketing business have agreed to indemnify TransCanada in the event the company is called upon to perform under the obligations.

## SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

Quarterly consolidated financial data for the years ended December 31, 2001 and 2000 is found under the heading "Selected Quarterly Consolidated Financial Data" on page 67 in the Annual Report and is hereby incorporated by reference.

## FORWARD-LOOKING INFORMATION

Certain information in this Management's Discussion and Analysis is forward-looking and is subject to important risks and uncertainties. The results or events predicted in this information may differ from actual results or events. Factors which could cause actual results or events to differ materially from current expectations include, among other things, the ability of TransCanada to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the availability and price of energy commodities, regulatory decisions, competitive factors in the pipeline and power industry sectors, and the current economic conditions in North America. For additional information on these and other factors, see the reports filed by TransCanada with Canadian securities regulators and with the United States Securities and Exchange Commission. TransCanada disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

## 2001 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) which is based on the Company's financial results prepared in accordance with Canadian GAAP. It compares the Company's financial performance in 2001 to 2000 and should be read in conjunction with the consolidated financial statements and accompanying notes. In addition, significant changes between 2000 and 1999 are highlighted. Note 20 to the consolidated financial statements describes the impact on the consolidated financial statements of significant differences between Canadian and United States GAAP.

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

The Board of Directors has appointed an Audit and Risk Management Committee consisting of unrelated, non-management directors which meets at least four times during the year with Management and independently with each of the internal and external auditors and as a group. 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 Canadian generally accepted accounting principles. The report of KPMG LLP on page 44 outlines the scope of their examination and their opinion on the consolidated financial statements.

| | |
|---|---|
| **HAROLD N. KVISLE** | **RUSSELL K. GIRLING** |
| *President and Chief Executive Officer* | *Executive Vice-President and Chief Financial Officer* |

February 25, 2002

## CONSOLIDATED INCOME

**Year ended December 31** (millions of dollars except per share amounts)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| **Revenues** | 5,249 | 4,421 | 4,239 |
| **Expenses** | | | |
| Operating expenses | 2,313 | 1,672 | 1,689 |
| Depreciation | 793 | 737 | 696 |
| Restructuring and other costs *(Note 18)* | 8 | – | 170 |
| | 3,114 | 2,409 | 2,555 |
| **Operating Income** | 2,135 | 2,012 | 1,684 |
| **Other Expenses/(Income)** | | | |
| Financial charges *(Note 7)* | 895 | 951 | 1,009 |
| Financial charges of joint ventures *(Note 8)* | 107 | 113 | 120 |
| Allowance for funds used during construction | (5) | (8) | (46) |
| Interest and other income | (72) | (107) | (38) |
| Gain on sale of assets | – | (37) | (91) |
| | 925 | 912 | 954 |
| **Income from Continuing Operations before Income Taxes** | 1,210 | 1,100 | 730 |
| **Income Taxes** *(Note 13)* | 473 | 371 | 178 |
| **Net Income from Continuing Operations** | 737 | 729 | 552 |
| **Net (Loss)/Income from Discontinued Operations** *(Note 19)* | (67) | 61 | (534) |
| **Net Income** | 670 | 790 | 18 |
| **Preferred Securities Charges** *(Note 9)* | 45 | 44 | 46 |
| **Preferred Share Dividends** | 22 | 35 | 52 |
| **Net Income/(Loss) Applicable to Common Shares** | 603 | 711 | (80) |
| **Net Income/(Loss) Applicable to Common Shares** | | | |
| Continuing operations | 670 | 650 | 454 |
| Discontinued operations | (67) | 61 | (534) |
| | 603 | 711 | (80) |
| **Net Income/(Loss) Per Share – Basic and Diluted** *(Note 11)* | | | |
| Continuing operations | $ 1.41 | $ 1.37 | $ 0.94 |
| Discontinued operations | (0.14) | 0.13 | (1.13) |
| | $ 1.27 | $ 1.50 | $ (0.19) |

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)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| **Cash Generated from Operations** | | | |
| Net income from continuing operations | 737 | 729 | 552 |
| Depreciation | 793 | 737 | 696 |
| Change in net unrealized position on energy trading contracts *(Note 12)* | 26 | (37) | – |
| Future income taxes | 120 | 91 | (108) |
| Gain on sale of assets | – | (37) | (91) |
| Power purchase arrangement payment | (110) | (212) | – |
| Other | (52) | 12 | (8) |
| Funds generated from continuing operations | 1,514 | 1,283 | 1,041 |
| Decrease/(increase) in operating working capital *(Note 16)* | 170 | (416) | 237 |
| Net cash provided by continuing operating activities | 1,684 | 867 | 1,278 |
| Net cash (used in)/provided by discontinued operating activities | (659) | 853 | 18 |
| | 1,025 | 1,720 | 1,296 |
| **Investing Activities** | | | |
| Capital expenditures | (492) | (812) | (1,824) |
| Acquisitions, net of cash acquired | (475) | (111) | (56) |
| Disposition of assets | 1,170 | 2,233 | 658 |
| Deferred amounts and other | 30 | (31) | 42 |
| Net cash provided by/(used in) investing activities | 233 | 1,279 | (1,180) |
| **Financing Activities** | | | |
| Dividends and preferred securities charges | (517) | (536) | (664) |
| Notes payable issued/(repaid), net | 186 | (25) | (228) |
| Long-term debt issued | – | – | 1,204 |
| Reduction of long-term debt | (793) | (2,139) | (699) |
| Non-recourse debt of joint ventures issued | 23 | 404 | 161 |
| Reduction of non-recourse debt of joint ventures | (132) | (282) | (148) |
| Partnership units of joint ventures issued | 59 | – | 312 |
| Preferred securities redeemed | (318) | – | – |
| Preferred shares issued | – | – | 194 |
| Preferred shares redeemed | – | (328) | (396) |
| Common shares issued | 24 | 5 | 204 |
| Net cash used in financing activities | (1,468) | (2,901) | (60) |
| **(Decrease)/Increase in Cash and Short-Term Investments** | (210) | 98 | 56 |
| **Cash and Short-Term Investments** | | | |
| Beginning of year | 509 | 411 | 355 |
| **Cash and Short-Term Investments** | | | |
| End of year | 299 | 509 | 411 |

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

## CONSOLIDATED BALANCE SHEET

**December 31** (millions of dollars)

| | 2001 | 2000 |
|---|---|---|
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and short-term investments | 299 | 509 |
| Accounts receivable | 551 | 575 |
| Inventories | 169 | 216 |
| Other | 42 | 28 |
| Unrealized gains on energy trading contracts *(Note 12)* | 152 | 582 |
| Current assets of discontinued operations *(Note 19)* | 113 | 3,473 |
| | 1,326 | 5,383 |
| **Unrealized Gains on Energy Trading Contracts** *(Note 12)* | 365 | 379 |
| **Long-Term Investments** *(Note 6)* | 268 | 235 |
| **Plant, Property and Equipment** *(Notes 4, 7 and 8)* | 17,849 | 17,709 |
| **Other Assets** | 71 | 70 |
| **Future Income Taxes** *(Note 13)* | – | 189 |
| **Long-Term Assets of Discontinued Operations** *(Note 19)* | 212 | 1,583 |
| | 20,091 | 25,548 |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current Liabilities** | | |
| Notes payable *(Note 14)* | 343 | 200 |
| Accounts payable | 670 | 594 |
| Accrued interest | 233 | 264 |
| Current portion of long-term debt *(Note 7)* | 483 | 612 |
| Current portion of non-recourse debt of joint ventures *(Note 8)* | 44 | 29 |
| Provision for loss on discontinued operations *(Note 19)* | 264 | 128 |
| Unrealized losses on energy trading contracts *(Note 12)* | 72 | 542 |
| Current liabilities of discontinued operations *(Note 19)* | 116 | 3,882 |
| | 2,225 | 6,251 |
| **Unrealized Losses on Energy Trading Contracts** *(Note 12)* | 112 | 170 |
| **Deferred Amounts** | 326 | 331 |
| **Long-Term Debt** *(Note 7)* | 9,347 | 9,928 |
| **Future Income Taxes** *(Note 13)* | 47 | – |
| **Non-Recourse Debt of Joint Ventures** *(Note 8)* | 1,295 | 1,296 |
| **Junior Subordinated Debentures** *(Note 9)* | 237 | 243 |
| **Long-Term Liabilities of Discontinued Operations** *(Note 19)* | 9 | 741 |
| | 13,598 | 18,960 |
| **Shareholders' Equity** | | |
| Preferred securities *(Note 9)* | 675 | 969 |
| Preferred shares *(Note 10)* | 389 | 389 |
| Common shares *(Note 11)* | 4,564 | 4,540 |
| Contributed surplus | 263 | 263 |
| Retained earnings | 589 | 414 |
| Foreign exchange adjustment *(Note 12)* | 13 | 13 |
| | 6,493 | 6,588 |
| **Commitments and Contingencies** *(Note 17)* | | |
| | 20,091 | 25,548 |

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

On behalf of the Board:

**HAROLD N. KVISLE**
*Director*

**HARRY G. SCHAEFER**
*Director*

## CONSOLIDATED RETAINED EARNINGS

**Year ended December 31** (millions of dollars)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| Balance at beginning of year | 414 | 119 | 740 |
| Net income | 670 | 790 | 18 |
| Preferred securities charges | (45) | (44) | (46) |
| Preferred share dividends | (22) | (35) | (52) |
| Common share dividends | (428) | (379) | (527) |
| Accounting changes | – | (37) | (3) |
| Other | – | – | (11) |
| | 589 | 414 | 119 |

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, 2001 and 2000 and the consolidated statements of income, retained earnings and cash flows for each of the years in the three-year period ended December 31, 2001. 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, 2001 and 2000 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2001 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

**CHARTERED ACCOUNTANTS**
*Calgary, Canada*

February 25, 2002

# NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

## TRANSMISSION

The Transmission business owns and operates a natural gas transmission system in Alberta (the Alberta System), 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 natural gas transmission facilities in Canada and the United States.

## POWER

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

## NOTE 1 – ACCOUNTING POLICIES

The consolidated financial statements of the Company have been prepared by Management in accordance with Canadian generally accepted accounting principles (Canadian GAAP). These accounting principles are different in some respects from United States generally accepted accounting principles (U.S. GAAP) and the significant differences are described in Note 20. Amounts are stated in Canadian dollars unless otherwise indicated.

The Company's financial statements reflect the plan approved by the Board of Directors in 2001 to dispose of the Gas Marketing business which is included in discontinued operations. All prior period comparative results have been restated to reflect Gas Marketing as discontinued operations. Certain other comparative figures have been reclassified to conform with the current year's presentation.

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

### BASIS OF PRESENTATION

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

### REGULATION

The Alberta System is regulated by the Alberta Energy and Utilities Board (EUB) and the Canadian Mainline and the BC System are subject to the authority of the National Energy Board (NEB). All Canadian natural gas transmission operations are regulated with respect to the determination of tolls, construction and operations. In November 2001, the NEB approved TransCanada's 2001 and 2002 Tolls and Tariff Application for the Canadian Mainline which resolved all issues other than cost of capital. The NEB also determined that interim tolls will remain in place until a final decision is made on cost of capital. Any adjustments to the interim tolls will be recorded in accordance with the final NEB decision. The natural gas pipelines in the United States, the Ocean State Power plant and the Curtis Palmer 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 with maturities of three months or less are considered to be cash equivalents and are recorded at cost, which approximates market value.

### INVENTORIES

Inventories are carried at the lower of average cost or net realizable value.

### PLANT, PROPERTY AND EQUIPMENT

*Transmission*

Plant, property and equipment of natural gas transmission operations are carried at cost. Depreciation is calculated on the straight-line basis. Pipeline and compression equipment are depreciated at annual rates ranging from two to five per cent and metering and other plant are depreciated at various rates. Removal and site restoration costs are not determinable and will be recorded when reasonably estimable and when approved by the regulators. An allowance for funds used during construction, using the rate of return on rate base approved by the regulators, is capitalized and included in the cost of gas transmission plant.

*Power and Other*

Plant, property and equipment in the power business are recorded at cost and depreciated on the straight-line basis over estimated service lives at average annual rates generally ranging from two to five per cent. Other plant, property and equipment are recorded at cost and depreciated on a straight-line basis over estimated useful lives at average annual rates ranging from four to twenty per cent.

**INCOME TAXES**

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

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

**FOREIGN CURRENCY TRANSLATION**

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

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

**PRICE RISK MANAGEMENT AND FINANCIAL INSTRUMENTS**

The Company engages in price risk management practices for both trading and non-trading activities. Trading activities are provided by the Company's power marketing operations and are accounted for using the mark-to-market method. Trading activities may be conducted through a variety of instruments with third parties, including contracts for physical delivery of the 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 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 Statement of Consolidated Income. They result primarily from transactions originating or settling within that period, and the impact of price movements on outstanding contracts. Cash inflows and outflows associated with energy trading contracts are recognized in cash from operations as settlement occurs.

The Company utilizes derivative and other financial instruments to manage price risk exposure to power generation operations and 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 that qualifies as a hedge is settled early, the gain or loss at settlement is deferred and recognized when the gain or loss on the hedged transaction is recognized. Premiums paid or received with respect to derivatives that are hedges are deferred and amortized to income over the term of the hedge.

**EMPLOYEE BENEFIT PLANS**

The Company sponsors 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. The expected return on pension plan assets is determined using market-related values. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The excess of the net actuarial gain or loss over 10 per cent of the greater of the benefit obligation and the fair value of plan assets is amortized over the average remaining service period of the active employees.

## NOTE 2 – ACCOUNTING CHANGES

**EARNINGS PER SHARE**

Effective January 1, 2001, the Company adopted the new standard of the Canadian Institute of Chartered Accountants (CICA) with respect to earnings per share. The new standard requires a new basis for calculating diluted earnings per share using the treasury stock method instead of the imputed earnings approach to determine the dilutive effects of warrants, options and equivalents. This accounting change was applied retroactively but did not significantly impact previously reported earnings per share.

## NOTE 3 – SEGMENTED INFORMATION

**NET INCOME/(LOSS)**[1]

**Year ended December 31** (millions of dollars)

| | Transmission | Power | Corporate | Total |
|---|---|---|---|---|
| **2001** | | | | |
| Revenues | 3,880 | 1,369 | – | 5,249 |
| Operating expenses | (1,226) | (1,064) | (23) | (2,313) |
| Depreciation | (753) | (37) | (3) | (793) |
| Restructuring and other costs | – | – | (8) | (8) |
| Operating income/(loss) | 1,901 | 268 | (34) | 2,135 |
| Financial and preferred equity charges | (856) | (15) | (91) | (962) |
| Financial charges of joint ventures | (98) | (9) | – | (107) |
| Other income | 30 | 13 | 34 | 77 |
| Income taxes | (392) | (100) | 19 | (473) |
| Continuing Operations | 585 | 157 | (72) | 670 |
| Discontinued Operations | | | | (67) |
| Net Income Applicable to Common Shares | | | | 603 |

**Year ended December 31** (millions of dollars)

| | Transmission | Power | Corporate | Total |
|---|---|---|---|---|
| **2000** | | | | |
| Revenues | 3,856 | 565 | – | 4,421 |
| Operating expenses | (1,252) | (389) | (31) | (1,672) |
| Depreciation | (698) | (35) | (4) | (737) |
| Operating income/(loss) | 1,906 | 141 | (35) | 2,012 |
| Financial and preferred equity charges | (877) | (3) | (150) | (1,030) |
| Financial charges of joint ventures | (101) | (12) | – | (113) |
| Other income | 52 | 9 | 54 | 115 |
| Gain on sale of assets | 11 | 26 | – | 37 |
| Income taxes | (368) | (56) | 53 | (371) |
| Continuing Operations | 623 | 105 | (78) | 650 |
| Discontinued Operations | | | | 61 |
| Net Income Applicable to Common Shares | | | | 711 |

**Year ended December 31** (millions of dollars)

| | Transmission | Power | Corporate | Total |
|---|---|---|---|---|
| **1999** | | | | |
| Revenues | 3,789 | 450 | – | 4,239 |
| Operating expenses | (1,302) | (353) | (34) | (1,689) |
| Depreciation | (658) | (30) | (8) | (696) |
| Restructuring and other costs | – | – | (170) | (170) |
| Operating income/(loss) | 1,829 | 67 | (212) | 1,684 |
| Financial and preferred equity charges | (876) | – | (231) | (1,107) |
| Financial charges of joint ventures | (107) | (13) | – | (120) |
| Other income | 46 | 9 | 29 | 84 |
| Gain on sale of assets | 91 | – | – | 91 |
| Income taxes | (306) | (23) | 151 | (178) |
| Continuing Operations | 677 | 40 | (263) | 454 |
| Discontinued Operations | | | | (534) |
| Net Loss Applicable to Common Shares | | | | (80) |

[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)

| | 2001 | 2000 |
|---|---|---|
| Transmission | 17,269 | 17,455 |
| Power | 2,083 | 1,954 |
| Corporate | 414 | 1,083 |
| Continuing Operations | 19,766 | 20,492 |
| Discontinued Operations | 325 | 5,056 |
| | 20,091 | 25,548 |

**GEOGRAPHIC INFORMATION**

**Year ended December 31** (millions of dollars)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| **Revenues**[2] | | | |
| Canada – domestic | 3,277 | 2,802 | 2,694 |
| Canada – export | 1,329 | 1,120 | 1,013 |
| United States | 643 | 499 | 532 |
| | 5,249 | 4,421 | 4,239 |

[2] Revenues are attributed to countries based on country of origin of product or service.

**December 31** (millions of dollars)

| | 2001 | 2000 |
|---|---|---|
| **Plant, Property and Equipment** | | |
| Canada | 15,704 | 16,125 |
| United States | 2,145 | 1,584 |
| | 17,849 | 17,709 |

**CAPITAL EXPENDITURES**

**Year ended December 31** (millions of dollars)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| Transmission | 285 | 354 | 1,186 |
| Power | 121 | 104 | 117 |
| Corporate | 34 | 60 | 20 |
| Continuing Operations | 440 | 518 | 1,323 |
| Discontinued Operations | 52 | 294 | 501 |
| | 492 | 812 | 1,824 |

## NOTE 4 – PLANT, PROPERTY AND EQUIPMENT

**December 31** (millions of dollars)

| | 2001 Cost | 2001 Accumulated Depreciation | 2001 Net Book Value | 2000 Net Book Value |
|---|---|---|---|---|
| **Transmission** | | | | |
| Alberta System | | | | |
| Pipeline | 4,810 | 1,607 | 3,203 | 3,192 |
| Compression | 1,489 | 413 | 1,076 | 1,069 |
| Metering and other | 964 | 258 | 706 | 866 |
| | 7,263 | 2,278 | 4,985 | 5,127 |
| Under construction | 33 | – | 33 | 53 |
| | 7,296 | 2,278 | 5,018 | 5,180 |
| Canadian Mainline | | | | |
| Pipeline | 8,659 | 2,708 | 5,951 | 6,132 |
| Compression | 3,400 | 738 | 2,662 | 2,727 |
| Metering and other | 444 | 124 | 320 | 309 |
| | 12,503 | 3,570 | 8,933 | 9,168 |
| Under construction | 21 | – | 21 | 34 |
| | 12,524 | 3,570 | 8,954 | 9,202 |
| North American pipelines and other | 3,998 | 1,484 | 2,514 | 2,445 |
| | 23,818 | 7,332 | 16,486 | 16,827 |
| **Power** | | | | |
| Power generation facilities | 1,620 | 366 | 1,254 | 725 |
| Other | 77 | 34 | 43 | 46 |
| | 1,697 | 400 | 1,297 | 771 |
| **Corporate** | 124 | 58 | 66 | 111 |
| | 25,639 | 7,790 | 17,849 | 17,709 |

## NOTE 5 – JOINT VENTURE INVESTMENTS

(millions of dollars)

| | | TransCanada's Proportionate Share | | | | |
|---|---|---|---|---|---|---|
| | Ownership Interest | Income Before Income Taxes Year ended December 31 2001 | 2000 | 1999 | Net Assets December 31 2001 | 2000 |
| **Transmission Joint Ventures** | | | | | | |
| Great Lakes | 50.0% | 89 | 84 | 85 | 473 | 433 |
| Iroquois | 41.0%[1] | 27 | 22 | 20 | 132 | 88 |
| Foothills | 50.0 – 74.5% | 26 | 33 | 29 | 215 | 204 |
| Trans Québec & Maritimes | 50.0% | 15 | 14 | 13 | 80 | 82 |
| TC PipeLines, LP | 33.4%[2] | 23 | 5 | – | 136 | 104 |
| Other | Various | 19 | 15 | 33 | 40 | 43 |
| **Power Joint Ventures** | | | | | | |
| TransCanada Power, L.P. | 35.6%[3] | 21 | 21 | 17 | 253 | 236 |
| ASTC Power Partnership | 50.0%[4] | – | – | – | 118 | – |
| Ocean State Power | [5] | – | 22 | 29 | – | – |
| | | 220 | 216 | 226 | 1,447 | 1,190 |

1 During 1999, the Company increased its interest in Iroquois from 29.0 per cent to 35.0 per cent. In May 2001, the Company increased its interest to 41.0 per cent.
2 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.
3 During 1999, the Company decreased its interest in TransCanada Power, L.P. from 39.8 per cent to 32.7 per cent. During 2000, the Company increased its interest to 41.6 per cent and in October 2001, decreased its interest to 35.6 per cent.
4 In December 2001, the Company purchased 50 per cent of ASTC Power Partnership, which is located in Alberta and holds a power purchase arrangement.
5 In October 2000, the Company increased its interest in the Ocean State Power plant from 70.1 per cent to 100 per cent and the investment was consolidated subsequent to that date.

Consolidated retained earnings at December 31, 2001 include undistributed earnings from these joint ventures of $347 million (2000 – $267 million).

**SUMMARIZED FINANCIAL INFORMATION OF JOINT VENTURES**

**Year ended December 31** (millions of dollars)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| **Income** | | | |
| Revenues | 592 | 603 | 606 |
| Operating expenses | (172) | (155) | (139) |
| Depreciation | (119) | (132) | (138) |
| Financial charges and other | (81) | (100) | (103) |
| Proportionate share of income before income taxes of joint ventures | 220 | 216 | 226 |

**Year ended December 31** (millions of dollars)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| **Cash Flows** | | | |
| Operations | 236 | 321 | 298 |
| Investing activities | (39) | (80) | (274) |
| Financing activities | (246) | (240) | (61) |
| Proportionate share of (decrease)/increase in cash and short-term investments of joint ventures | (49) | 1 | (37) |

**December 31** (millions of dollars)

| | 2001 | 2000 |
|---|---|---|
| **Balance Sheet** | | |
| Cash and short-term investments | 75 | 66 |
| Other current assets | 92 | 75 |
| Unrealized gains on energy trading contracts | 110 | – |
| Long-term investments | 132 | 123 |
| Plant, property and equipment | 2,490 | 2,492 |
| Other assets and deferred amounts | 25 | (33) |
| Current liabilities | (118) | (167) |
| Non-recourse debt | (1,295) | (1,296) |
| Future income taxes | (64) | (70) |
| Proportionate share of net assets of joint ventures | 1,447 | 1,190 |

## NOTE 6 – LONG-TERM INVESTMENTS

**December 31** (millions of dollars)

| | 2001 | 2000 |
|---|---|---|
| **Equity Investments** | | |
| Northern Border | 132 | 123 |
| Portland | 66 | 51 |
| Other | 70 | 61 |
| | 268 | 235 |

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. At December 31, 2001, the Company holds a 33.3 per cent interest (2000 – 21.4 per cent) in Portland Natural Gas Transmission System Partnership. Consolidated retained earnings at December 31, 2001 include undistributed earnings from these equity investments of $40 million (2000 – $37 million).

## NOTE 7 – LONG-TERM DEBT

| | Maturity Dates | 2001 Outstanding December 31[1] | 2001 Weighted Average Interest Rate[2] | 2000 Outstanding December 31[1] | 2000 Weighted Average Interest Rate[2] |
|---|---|---|---|---|---|
| **Alberta System** | | | | | |
| Debentures and Notes | | | | | |
| Canadian dollars | 2003 to 2024 | 819 | 11.0% | 840 | 11.1% |
| U.S. dollars (2001 and 2000 – US$625) | 2002 to 2023 | 995 | 8.2% | 938 | 8.2% |
| Medium-Term Notes | | | | | |
| Canadian dollars | 2002 to 2030 | 774 | 7.4% | 791 | 7.4% |
| U.S. dollars (2001 – US$233; 2000 – US$333) | 2026 to 2029 | 371 | 7.7% | 499 | 7.3% |
| Unsecured Loans | | | | | |
| U.S. dollars (2001 and 2000 – US$107) | 2003 | 170 | 2.3% | 160 | 7.1% |
| | | 3,129 | | 3,228 | |
| Foreign exchange differential recoverable through the tollmaking process | | (322) | | (254) | |
| | | 2,807 | | 2,974 | |
| **Canadian Mainline** | | | | | |
| First Mortgage Pipe Line Bonds | | | | | |
| Pounds Sterling (2001 and 2000 – £25) | 2007 | 58 | 16.5% | 56 | 16.5% |
| Debentures | | | | | |
| Canadian dollars | 2002 to 2020 | 1,455 | 10.9% | 1,455 | 10.9% |
| U.S. dollars (2001 and 2000 – US$800) | 2012 to 2023 | 1,274 | 9.2% | 1,200 | 9.2% |
| Medium-Term Notes | | | | | |
| Canadian dollars | 2002 to 2031 | 2,585 | 7.1% | 2,932 | 7.1% |
| U.S. dollars (2001 and 2000 – US$120) | 2010 | 191 | 6.1% | 180 | 6.1% |
| | | 5,563 | | 5,823 | |
| Foreign exchange differential recoverable through the tollmaking process | | (337) | | (250) | |
| | | 5,226 | | 5,573 | |
| **Other** | | | | | |
| Medium-Term Notes | | | | | |
| Canadian dollars | 2005 to 2030 | 342 | 6.6% | 342 | 6.6% |
| U.S. dollars (2001 – US$665; 2000 – US$785) | 2006 to 2029 | 1,059 | 6.8% | 1,178 | 6.8% |
| Subordinated Debentures | | | | | |
| U.S. dollars (2001 and 2000 – US$57) | 2006 | 91 | 9.1% | 86 | 9.1% |
| Long-Term Debt of Subsidiaries | | | | | |
| U.S. dollars (2001 – US$123; 2000 – US$138) | 2002 to 2011 | 195 | 8.3% | 207 | 8.2% |
| Unsecured Loan | | | | | |
| Canadian dollars | 2003 | 110 | 8.4% | 180 | 7.6% |
| | | 1,797 | | 1,993 | |
| | | 9,830 | | 10,540 | |
| Less: Current Portion of Long-Term Debt | | 483 | | 612 | |
| | | 9,347 | | 9,928 | |

[1] Amounts outstanding are stated in millions of Canadian dollars; amounts denominated in currencies other than Canadian dollars are stated in millions.
[2] Weighted average interest rates are stated as at the respective outstanding dates. The effective weighted average interest rates resulting from swap agreements are as follows: Alberta System U.S. dollar unsecured loans – 8.3 per cent (2000 – 8.3 per cent); and Other U.S. dollar subordinated debentures – 8.9 per cent (2000 – 8.9 per cent).

**MANDATORY RETIREMENTS**

Mandatory retirements resulting from maturities and sinking fund obligations of the long-term debt of the Company approximate: 2002 – $483 million; 2003 – $550 million; 2004 – $370 million; 2005 – $358 million and 2006 – $503 million.

**MEDIUM-TERM NOTES**

The Company has established a medium-term note program in the United States. At December 31, 2001, the Company can issue medium-term notes of up to US$750 million under this program.

**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. No redemptions have been made to December 31, 2001.

**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 in 2002 and 2003.

**OTHER**

*Medium-Term Notes*

Medium-term notes amounting to $150 million and US$145 million have retraction provisions which entitle the holders to require redemption of the principal plus accrued and unpaid interest in 2005 and 2004, respectively. The Company also has the option to redeem the US$145 million medium-term notes in 2004. If the U.S. dollar medium-term notes remain outstanding, the interest rate will change in 2004 from 6.4 per cent to a rate based on the then U.S. Treasury 30 year bond yield plus a market-based corporate credit spread.

**FINANCIAL CHARGES**

**Year ended December 31** (millions of dollars)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| Interest on long-term debt | 890 | 974 | 1,026 |
| Regulatory deferrals and amortizations | (24) | (13) | 6 |
| Short-term interest and other financial charges | 38 | 47 | 58 |
| | 904 | 1,008 | 1,090 |
| Financial charges – discontinued operations | (9) | (57) | (81) |
| | 895 | 951 | 1,009 |

The Company made interest payments of $936 million, $1,024 million and $1,062 million for the years ended December 31, 2001, 2000 and 1999, respectively.

## NOTE 8 – NON-RECOURSE DEBT OF JOINT VENTURES

| | Maturity Dates | 2001 Outstanding December 31[1] | 2001 Weighted Average Interest Rate[2] | 2000 Outstanding December 31[1] | 2000 Weighted Average Interest Rate[2] |
|---|---|---|---|---|---|
| **Great Lakes** | | | | | |
| Senior Unsecured Notes | | | | | |
| (2001 – US$284; 2000 – US$297) | 2003 to 2030 | 452 | 8.1% | 446 | 8.2% |
| **Iroquois** | | | | | |
| Bank Loan | | | | | |
| (2001 – US$153; 2000 – US$136) | 2009 to 2010 | 244 | 7.3% | 204 | 8.1% |
| **Foothills** | | | | | |
| Senior Unsecured Notes | 2005 | 336 | 3.1% | 343 | 5.6% |
| Senior Secured Notes | 2005 | 63 | 6.3% | 65 | 8.4% |
| **Trans Québec & Maritimes** | | | | | |
| First Mortgage Bonds | 2005 to 2010 | 143 | 7.3% | 143 | 7.3% |
| Term Loan | 2003 | 42 | 4.6% | – | – |
| **TransCanada Power, L.P.** | | | | | |
| Bank Loan[3] | | – | – | 66 | 6.4% |
| **TC PipeLines, LP** | | | | | |
| Senior Unsecured Notes | | | | | |
| (2001 and 2000 – US$7) | 2003 | 11 | 5.3% | 11 | 7.6% |
| **Other** | 2002 to 2010 | 48 | 6.5% | 47 | 7.1% |
| | | 1,339 | | 1,325 | |
| Less: Current Portion of Non-Recourse Debt of Joint Ventures | | 44 | | 29 | |
| | | 1,295 | | 1,296 | |

[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. At December 31, 2001, the effective weighted average interest rates on the bank loan of Iroquois and notes of Foothills resulting from swap agreements are 7.6 per cent (2000 – 7.8 per cent) and 5.9 per cent (2000 – 6.7 per cent), respectively.
[3] In October 2001, TransCanada Power, L.P. issued 5,660,000 new Partnership units and used the net proceeds to fully repay the bank loan.

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: 2002 – $44 million; 2003 – $231 million; 2004 – $38 million; 2005 – $339 million and 2006 – $26 million.

### FINANCIAL CHARGES OF JOINT VENTURES

**Year ended December 31** (millions of dollars)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| Interest on long-term non-recourse debt | 107 | 149 | 139 |
| Other | – | 5 | 10 |
| | 107 | 154 | 149 |
| Financial charges of joint ventures – discontinued operations | – | (41) | (29) |
| | 107 | 113 | 120 |

The Company's proportionate share of the interest payments of joint ventures in continuing operations was $100 million, $99 million and $78 million for the years ended December 31, 2001, 2000 and 1999, respectively.

## NOTE 9 – JUNIOR SUBORDINATED DEBENTURES AND PREFERRED SECURITIES

**December 31** (millions of dollars)

| | Maturity Dates | 2001 | 2000 |
|---|---|---|---|
| **Junior Subordinated Debentures** | | | |
| 8.75% Issue | | | |
| (2001 and 2000 – US$160 million) | 2045 | 218 | 218 |
| **Preferred Securities** | | | |
| 8.25% and 8.50% Issues | | | |
| (2001 – US$12 million; 2000 – US$17 million) | 2047 | 19 | 25 |
| | | 237 | 243 |

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

*Junior Subordinated Debentures*

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

*Preferred Securities*

The US$460 million 8.25 per cent Preferred Securities are redeemable by the Company at par at any time on or after October 8, 2003, and in certain circumstances, prior to that date. The Company may elect to defer interest payments on the Preferred Securities and settle the deferred interest in either cash or common shares.

Since the deferred interest may be settled through the issuance of common shares at the option of the Company, the Preferred Securities are classified into their respective debt and equity components. The equity component of the Preferred Securities is $675 million at December 31, 2001 (2000 – $969 million).

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

## NOTE 10 – PREFERRED SHARES

**December 31**

| | Number of Shares (thousands) | Dividend Rate Per Share | Redemption Price Per Share | 2001 (millions of dollars) | 2000 (millions of dollars) |
|---|---|---|---|---|---|
| **CUMULATIVE FIRST PREFERRED SHARES** | | | | | |
| Series U | 4,000 | $2.80 | $50.00 | 195 | 195 |
| Series Y | 4,000 | $2.80 | $50.00 | 194 | 194 |
| | | | | 389 | 389 |

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

During 2000, the Company redeemed $328 million of preferred shares. 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, 1999** | 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 |
| Issued for cash or cash equivalent | | |
| Exercise of options | 1,718 | 24 |
| **Outstanding at December 31, 2001** | 476,631 | 4,564 |

**COMMON SHARES ISSUED AND OUTSTANDING**

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

**NET INCOME PER SHARE**

Basic and diluted earnings per share is calculated based on the weighted average number of common shares outstanding during the year of 475.8 million and 476.6 million (2000 - 474.6 million and 475.2 million; 1999 - 469.5 million and 470.0 million) respectively.

**STOCK OPTIONS**

| | *Number of Shares (thousands)* | *Weighted Average Exercise Prices* | *Options Exercisable (thousands)* |
|---|---|---|---|
| **Outstanding at January 1, 1999** | 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 |
| Granted | 2,142 | $ 18.07 | |
| Exercised | (1,718) | $ 14.08 | |
| Cancelled or expired | (1,365) | $ 21.45 | |
| **Outstanding at December 31, 2001** | 14,450 | $ 18.42 | 11,376 |

The following table summarizes information about stock options outstanding at December 31, 2001:

| | **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 $13.91 | 3,006 | 7.9 | $ 10.88 | 1,668 | $ 11.10 |
| $14.21 to $18.89 | 3,817 | 7.7 | $ 17.38 | 2,482 | $ 17.05 |
| $19.00 to $20.59 | 4,340 | 6.7 | $ 20.15 | 3,981 | $ 20.14 |
| $21.00 to $24.61 | 3,287 | 6.2 | $ 24.23 | 3,245 | $ 24.26 |
| | 14,450 | 7.1 | $ 18.42 | 11,376 | $ 19.32 |

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, 2001, an additional seven 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 2001 with certain amendments.

***Restriction on Dividends***

Certain terms of the Company's preferred shares, preferred securities, junior subordinated debentures and debt instruments could restrict the Company's ability to declare dividends on preferred and common shares. At December 31, 2001, 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 power 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.

***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, 2001, for foreign currency and interest rate derivatives, total credit risk and the largest credit exposure to a single counterparty are $398 million and $107 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, 2001 and 2000, 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.

**Liability at December 31** (millions of dollars)

| | 2001 | | 2000 | |
|---|---|---|---|---|
| | *Carrying Amount* | *Fair Value* | *Carrying Amount* | *Fair Value* |
| **Foreign Exchange Risk** | | | | |
| Cross-currency swaps | | | | |
| U.S. Dollars | 5 | 5 | 18 | 18 |
| Forward foreign exchange contracts | | | | |
| U.S. Dollars | 6 | 6 | 1 | 1 |

The principal amounts of cross-currency swaps are US$150 million (2000 - US$150 million). Principal amounts of forward foreign exchange contracts are US$375 million (2000 – US$35 million).

### RECONCILIATION OF FOREIGN EXCHANGE ADJUSTMENT

**December 31** (millions of dollars)

| | 2001 | 2000 |
|---|---|---|
| Balance at beginning of year | 13 | 18 |
| Translation gains/(losses) on foreign currency denominated net assets | 11 | (1) |
| Foreign exchange losses on derivatives, and other | (11) | (4) |
| | 13 | 13 |

**ENERGY PRICE RISK MANAGEMENT**

The Company's power marketing operations offer integrated price risk management services to the power energy sector. The Company executes energy trading contracts related to these commodities for overall management of its contractual portfolio. The Company's portfolio of power energy trading contracts is primarily comprised of forward, swap and option contracts for periods of up to 19 years, with fixed and floating price commitments. The net pre-tax unrealized (loss)/gain on power energy trading contracts included in revenues for 2001 was $(26) million (2000 – $37 million).

The fair value of power energy trading contracts as at December 31, 2001 and 2000 is shown in the table below.

**Year ended December 31** (millions of dollars)

| | 2001 | 2000 |
|---|---|---|
| Assets | 517 | 961 |
| Liabilities | 184 | 712 |

Notional volumes are 6,013 gigawatt hours (GWh) (2000 - 2,795 GWh) for power swaps. Volumes are 149,516 GWh (2000 – 105,800 GWh) for power forward contracts, including volumes which are held through a joint venture.

**U.S. DOLLAR TRANSACTION HEDGES**

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

**FOREIGN EXCHANGE AND INTEREST RATE MANAGEMENT ACTIVITY**

The Company manages the foreign exchange risk of U.S. dollar debt 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.

**Asset/(Liability) at December 31** (millions of dollars)

| | 2001 | | 2000 | |
|---|---|---|---|---|
| | *Carrying Amount* | *Fair Value* | *Carrying Amount* | *Fair Value* |
| **Foreign Exchange Risk** | | | | |
| Cross-currency swaps | 88 | 88 | 65 | 65 |
| **Interest Rate Risk** | | | | |
| Interest rate swaps | | | | |
| Canadian dollars | 4 | 26 | 2 | 12 |
| U.S. dollars | – | (3) | (1) | (3) |

The principal amounts of cross-currency swaps are US$407 million (2000 – US$425 million). Notional principal amounts for interest rate swaps are $780 million (2000 – $780 million) and US$125 million (2000 – US$125 million).

The Company manages the foreign exchange risk of its other U.S. dollar debt through the use of interest rate derivatives. The carrying amount and fair value of U.S. dollar interest rate swaps at December 31, 2001 is $2 million (2000 – nil) and $30 million (2000 – $(4) million), respectively. Notional principal amounts are US$200 million (2000 – 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 fair value of the outstanding derivatives is $(2) million and there is no related credit exposure at December 31, 2001.

**OTHER FAIR VALUES**

**December 31** (millions of dollars)

| | 2001 | | 2000 | |
|---|---|---|---|---|
| | *Carrying Amount* | *Fair Value* | *Carrying Amount* | *Fair Value* |
| **Long-Term Debt** | | | | |
| Alberta System | 3,129 | 3,611 | 3,228 | 3,616 |
| Canadian Mainline | 5,563 | 6,245 | 5,823 | 6,445 |
| Other | 1,797 | 1,837 | 1,993 | 2,035 |
| **Non-Recourse Debt of Joint Ventures** | 1,339 | 1,408 | 1,325 | 1,349 |
| **Junior Subordinated Debentures** | 274 | 276 | 265 | 266 |

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

## NOTE 13 – INCOME TAXES

### PROVISION FOR INCOME TAXES

**Year ended December 31** (millions of dollars)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| **Current** | | | |
| Canada | 307 | 246 | 177 |
| Foreign | 46 | 34 | 109 |
| | 353 | 280 | 286 |
| **Future** | | | |
| Canada | 63 | 58 | (99) |
| Foreign | 57 | 33 | (9) |
| | 120 | 91 | (108) |
| | 473 | 371 | 178 |

### GEOGRAPHIC COMPONENTS OF INCOME

**Year ended December 31** (millions of dollars)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| Canada | 910 | 897 | 473 |
| Foreign | 300 | 203 | 257 |
| Income from continuing operations before income taxes | 1,210 | 1,100 | 730 |

### RECONCILIATION OF INCOME TAX EXPENSE

**Year ended December 31** (millions of dollars)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| Income from continuing operations before income taxes | 1,210 | 1,100 | 730 |
| Income from regulated operations not subject to tax currently | (130) | (245) | (336) |
| | 1,080 | 855 | 394 |
| Federal and provincial statutory tax rate | 42.1% | 44.6% | 44.6% |
| Expected income tax expense | 455 | 381 | 176 |
| Non-deductible expenses | 3 | 3 | 15 |
| Net difference between the federal and provincial statutory tax rate and rate of foreign authorities | (13) | (8) | (33) |
| Large corporations tax | 31 | 32 | 32 |
| Change in valuation allowance | – | (8) | – |
| Adjustment to future tax assets and liabilities for enacted changes in tax laws and rates | – | (28) | – |
| Other | (3) | (1) | (12) |
| Actual income tax expense | 473 | 371 | 178 |

**FUTURE INCOME TAX ASSETS AND LIABILITIES**

**December 31** (millions of dollars)

| | 2001 | 2000 |
|---|---|---|
| Net operating and capital loss carryforwards | 180 | 276 |
| Deferred costs | 91 | 100 |
| Deferred revenue | 49 | 56 |
| Alternative minimum tax credits | 40 | 40 |
| Other | 19 | 47 |
| | 379 | 519 |
| Less: Valuation allowance | 25 | 25 |
| Future income tax assets, net of valuation allowance | 354 | 494 |
| Accelerated tax depreciation on plant and equipment | 318 | 242 |
| Investments in subsidiaries and partnerships | 80 | 49 |
| Other | 3 | 14 |
| Future income tax liabilities | 401 | 305 |
| Net future income tax (liabilities)/assets | (47) | 189 |

The Company follows the taxes payable method of accounting for income taxes related to the operations of the Canadian natural gas transmission operations. If the liability method of accounting had been used, additional future income tax liabilities in the amount of $1,716 million at December 31, 2001 (2000 – $1,722 million) would have been recorded and would be recoverable from future revenues.

**UNREMITTED EARNINGS OF FOREIGN INVESTMENTS**

Income taxes have not been provided on the unremitted earnings of foreign investments which the Company intends to indefinitely reinvest in foreign operations. If provision for these taxes had been made, future income tax liabilities would increase by approximately $54 million at December 31, 2001 (2000 – $41 million).

**INCOME TAX PAYMENTS**

Income tax payments of $310 million, $257 million and $196 million were made during the years ended December 31, 2001, 2000 and 1999, respectively.

## NOTE 14 – NOTES PAYABLE

| | 2001 | | 2000 | |
|---|---|---|---|---|
| | *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 | 340 | 2.3% | 35 | 5.9% |
| U.S. dollars | – | – | 114 | 6.0% |
| **Notes Payable of Joint Ventures** | | | | |
| Canadian dollars | 3 | 4.7% | 51 | 6.4% |
| | 343 | | 200 | |

The Company has unused lines of credit of $1.8 billion at December 31, 2001, 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 $1 million for the year ended December 31, 2001 (2000 – $2 million).

## NOTE 15 – EMPLOYEE FUTURE BENEFITS

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 $7 million for the year ended December 31, 2001 (2000 – $8 million). Information about the Company's defined benefit plans, is as follows.

| (millions of dollars) | *Pension Benefit Plans* 2001 | 2000 | *Other Benefit Plans* 2001 | 2000 |
|---|---|---|---|---|
| **Change in Benefit Obligation** | | | | |
| Benefit obligation – beginning of year | 644 | 626 | 55 | 48 |
| Current service cost | 12 | 15 | 2 | 2 |
| Interest cost | 41 | 44 | 4 | 3 |
| Employees' contributions | 1 | 1 | – | – |
| Benefits paid | (59) | (55) | (3) | (3) |
| Actuarial loss | 20 | 52 | 2 | 6 |
| Transfers to defined contribution plan | – | (35) | – | – |
| Corporate restructuring giving rise to curtailments | – | (4) | – | (1) |
| Benefit obligation – end of year | 659 | 644 | 60 | 55 |
| **Change in Plan Assets** | | | | |
| Plan assets at fair value – beginning of year | 612 | 652 | – | – |
| Actual return on plan assets | (8) | 34 | – | – |
| Employer contributions | 27 | 23 | 3 | 3 |
| Employee contributions | 1 | 1 | – | – |
| Benefits paid | (59) | (55) | (3) | (3) |
| Transfer to defined contribution plan | – | (43) | – | – |
| Plan assets at fair value – end of year | 573 | 612 | – | – |
| Funded status – plan deficit | (86) | (32) | (60) | (55) |
| Unamortized net actuarial loss | 123 | 65 | 7 | 6 |
| Unamortized transitional obligation related to regulated business | – | – | 29 | 31 |
| Accrued benefit asset/(liability), net of valuation allowance of nil | 37 | 33 | (24) | (18) |

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

| | *Pension Benefit Plans* 2001 | 2000 | *Other Benefit Plans* 2001 | 2000 |
|---|---|---|---|---|
| Discount rate | 6.75% | 6.80% | 6.85% | 6.90% |
| Expected long-term rate of return on plan assets | 7.10% | 7.24% | – | – |
| Rate of compensation increase | 3.50% | 3.50% | 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 2002. 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** (millions of dollars) | *Pension Benefit Plans* 2001 | 2000 | *Other Benefit Plans*[1] 2001 | 2000 |
|---|---|---|---|---|
| Current service cost | 12 | 15 | 2 | 2 |
| Interest cost | 41 | 44 | 4 | 3 |
| Expected return on plan assets | (41) | (45) | – | – |
| Amortization of transitional obligation related to regulated business | – | – | 2 | 2 |
| Corporate restructuring giving rise to curtailments | – | (5) | – | – |
| | 12 | 9 | 8 | 7 |
| Net benefit plan expense – discontinued operations | (2) | (2) | – | – |
| Net benefit plan expense – continuing operations | 10 | 7 | 8 | 7 |

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

Prior to January 1, 2000, the cost of post-employment benefits other than pensions was expensed when paid. Pension expense of $14 million for the year ended December 31, 1999 includes the expense related to both the Company's defined benefit and defined contribution pension plans.

## NOTE 16 – CHANGES IN OPERATING WORKING CAPITAL

**Year ended December 31** (millions of dollars)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| Decrease/(increase) in accounts receivable | 38 | (92) | 122 |
| Decrease/(increase) in inventories | 52 | 5 | (21) |
| (Increase)/decrease in other current assets | (12) | (6) | 5 |
| Increase/(decrease) in accounts payable | 105 | (318) | 122 |
| (Decrease)/increase in accrued interest | (13) | (5) | 9 |
| | 170 | (416) | 237 |

## 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)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| **Restructuring** | | | |
| Employee terminations | 8 | 5 | 98 |
| Real estate | – | – | 17 |
| | 8 | 5 | 115 |
| **Other** | | | |
| Asset impairments | – | – | 13 |
| Costs to exit a business and other | – | (5) | 42 |
| | – | (5) | 55 |
| | 8 | – | 170 |

In 1999, TransCanada recorded restructuring and other costs of $170 million including $47 million for terminations under its 1998 Merger Plan and $123 million as a result of the Company's 1999 Strategic Plan.

The 1999 Strategic Plan included costs of $51 million for the termination of 367 employees, represented by 61 management and 306 non-management positions. This plan is substantially complete. The remaining liability at December 31, 2001 is $8 million (2000 – $47 million).

In 1998, the Company recorded restructuring costs related to the business combination with NOVA Corporation (Merger Plan). The remaining restructuring liability related to the Merger Plan was $28 million at December 31, 2000. As at December 31, 2001, the Merger Plan is complete.

## NOTE 19 – DISCONTINUED OPERATIONS

In July 2001, the Board of Directors approved a plan to dispose of the Company's Gas Marketing business. The Gas Marketing business provided supply, transportation and asset management services, as well as structured financial products and services, to its customers in Canada and the northern tier of the United States. In 2001, the Company recorded a net loss of $87 million, after tax, related to Gas Marketing based on Management's estimates of proceeds and disposal costs. The Company's exit from Gas Marketing was substantially completed at December 31, 2001.

TransCanada remains contingently liable pursuant to obligations under certain energy trading contracts that relate to the divested Gas Marketing business. The Company has deferred recognition of after-tax gains on sales in the amount of approximately $100 million and has included this in the December 31, 2001 balance sheet provision. The gains will be recognized in income from discontinued operations as the underlying exposures reduce. The contingent liability under these obligations, which could be significant, is contingent on certain future events, the occurrence of which is not determinable, and the amount, if any, is dependent upon future prevailing market prices and conditions. The purchasers of the Gas Marketing business have agreed to indemnify TransCanada in the event the Company is called upon to perform under the obligations.

In December 1999, the Board of Directors approved a plan (December Plan) to dispose of the Company's International, Canadian midstream and certain other businesses. The Company recorded a net loss of $439 million, after tax, in 1999, related to the December Plan reflecting Management's best estimates. As a result of actual results and revised estimates, a positive $20 million after-tax adjustment was recorded in 2001 (2000 – $200 million). The disposals under the December Plan were substantially completed at December 31, 2001.

In April 1999, the Board of Directors approved a plan (April Plan) to dispose of ANGUS Chemical Company, TransCanada's U.S. midstream business, 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 disposals under the April Plan were completed at December 31, 2001.

Realized proceeds from disposals of discontinued operations were $1.2 billion in 2001, compared to the original estimate of $0.9 billion.

**REVENUES AND NET INCOME/(LOSS)**

**Year ended December 31** (millions of dollars)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| **Revenues** | | | |
| April Plan | – | 119 | 2,786 |
| December Plan | 21 | 2,827 | 3,685 |
| Gas Marketing | 12,874 | 12,266 | 7,617 |
| | 12,895 | 15,212 | 14,088 |
| **Net Income/(Loss)**[1] | | | |
| April Plan | – | – | (7) |
| December Plan | – | – | 40 |
| Asset impairments[2] | – | – | (285) |
| Gas Marketing | 5 | (252) | (15) |
| | 5 | (252) | (267) |
| Income taxes | (2) | 113 | 152 |
| Results of operations prior to plan approval | 3 | (139) | (115) |
| Net Gain/(Loss) from Discontinued Operations | | | |
| April Plan[1] | – | – | (19) |
| Income taxes | – | – | 39 |
| | – | – | 20 |
| December Plan[1] | 34 | 295 | (442) |
| Income taxes | (14) | (95) | 3 |
| | 20 | 200 | (439) |
| Gas Marketing[1] | (139) | – | – |
| Incomes taxes | 49 | – | – |
| | (90) | – | – |
| | (67) | 61 | (534) |

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

[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.

**OTHER FINANCIAL INFORMATION**

**December 31** (millions of dollars)

| | 2001 | 2000 |
|---|---|---|
| **Current Assets** | | |
| Accounts receivable | 104 | 1,586 |
| Unrealized gains on energy trading contracts | – | 1,752 |
| Other current assets | 9 | 135 |
| | 113 | 3,473 |
| **Unrealized Gains on Energy Trading Contracts** | – | 355 |
| **Long-Term Investments** | – | 535 |
| **Plant, Property and Equipment** | 14 | 336 |
| **Other Non-Current Assets** | 198 | 357 |
| | 325 | 5,056 |
| **Current Liabilities** | | |
| Accounts payable | 116 | 2,083 |
| Unrealized losses on energy trading contracts | – | 1,799 |
| | 116 | 3,882 |
| **Unrealized Losses on Energy Trading Contracts** | – | 438 |
| **Long-Term and Non-Recourse Debt** | – | 213 |
| **Other Non-Current Liabilities** | 9 | 90 |
| | 125 | 4,623 |
| **Net Assets of Discontinued Operations** | 200 | 433 |

The provision for loss on discontinued operations at December 31, 2001 was $264 million (December 31, 2000 – $128 million). This was comprised of $129 million relating to Gas Marketing and $135 million relating to the December Plan.

## NOTE 20 – SIGNIFICANT DIFFERENCES BETWEEN CANADIAN AND U.S. GAAP

### NET INCOME RECONCILIATION

**Year ended December 31** (millions of dollars except per share amounts)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| Net income from continuing operations as reported in accordance with Canadian GAAP | 737 | 729 | 552 |
| U.S. GAAP adjustments | | | |
| Preferred securities charges[1] | (77) | (78) | (82) |
| Tax impact of preferred securities charges | 32 | 34 | 36 |
| Unrealized loss on derivatives[2] | (14) | – | – |
| Tax impact of loss on derivatives | 6 | – | – |
| Gain on early retirement of long-term debt[3] | – | (15) | – |
| Tax impact on gain on early retirement of long-term debt | – | 2 | – |
| Income taxes from substantively enacted tax rates[4] | 28 | (28) | – |
| Income taxes[5] | – | – | (15) |
| Income from continuing operations in accordance with U.S. GAAP | 712 | 644 | 491 |
| Net (loss)/income from discontinued operations in accordance with U.S. GAAP[6] | (67) | 61 | (486) |
| Income before cumulative effect of the application SFAS No. 133 in accordance with U.S. GAAP[2] | 645 | 705 | 5 |
| Cumulative effect of the application of SFAS No. 133, net of tax | (2) | – | – |
| Extraordinary item: | | | |
| Gain on early retirement of long-term debt, net of tax | – | 13 | – |
| Net income in accordance with U.S. GAAP | 643 | 718 | 5 |
| Basic and diluted net income/(loss) per share in accordance with U.S. GAAP | | | |
| Continuing operations | $ 1.45 | $ 1.28 | $ 0.91 |
| Discontinued operations | (0.14) | 0.13 | (1.03) |
| Extraordinary item | – | 0.03 | – |
| | $ 1.31 | $ 1.44 | $ (0.12) |

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

2 Effective January 1, 2001, the Company adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 133 "Accounting for Derivatives and Hedging Activities". SFAS No. 133 requires that all derivatives be recognized as assets and liabilities on the balance sheet and measured at fair value.

For derivatives designated as fair value hedges, changes in the fair value are recognized in earnings together with an equal or lesser amount of changes in the fair value of the hedged item attributable to the hedged risk. For derivatives designated as cash flow hedges, changes in the fair value of the derivative that are effective in offsetting the hedged risk are recognized in other comprehensive income until the hedged item is recognized in earnings. Any ineffective portion of the change in fair value is recognized in earnings each period.

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

During 2001, net gains of $36 million from the hedges of changes in the fair value of long-term debt, and offsetting net losses of $44 million in the fair value of the hedged item were included in earnings as an adjustment to interest expense and foreign exchange losses. The difference of the change in the fair value of the derivative as compared to the change in the fair value of the hedged item of $(8) million, after tax, is included in earnings for U.S. GAAP purposes. During 2001, no amounts of the derivatives' gains or losses were excluded from the assessment of hedge effectiveness in fair value hedging relationships.

No amounts were included in income in 2001 with respect to cash flow hedges. For amounts included in other comprehensive income as at December 31, 2001, $3 million relates to the hedge of interest rate risk and $2 million relates to the hedge of foreign exchange rate risk. Of these amounts, none are expected to be recorded in earnings during 2002.

As at December 31, 2001, additional assets of $162 million and liabilities of $187 million were recorded for U.S. GAAP purposes to reflect the fair value of derivatives designated as hedges and the corresponding change in the fair value of items designated as hedges.

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

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

5 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.

6 In 1999, the loss from discontinued operations was $48 million lower than the amount recorded under Canadian GAAP as a result of differences in previously recorded asset impairment provisions.

### CONDENSED STATEMENT OF CONSOLIDATED INCOME[8]

**Year ended December 31** (millions of dollars)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| Revenues | 4,855 | 4,019 | 3,858 |
| Operating expenses | 2,320 | 1,704 | 1,777 |
| Depreciation | 676 | 609 | 556 |
| Restructuring and other costs | 8 | – | 170 |
| | 3,004 | 2,313 | 2,503 |
| Operating income | 1,851 | 1,706 | 1,355 |
| Other (income)/expenses | | | |
| Equity income | (203) | (236) | (240) |
| Other expenses | 936 | 935 | 954 |
| Income taxes | 406 | 363 | 150 |
| | 1,139 | 1,062 | 864 |
| Income from continuing operations in accordance with U.S. GAAP | 712 | 644 | 491 |
| Net (loss)/income from discontinued operations in accordance with U.S. GAAP | (67) | 61 | (486) |
| Income before cumulative effect of the application of SFAS No. 133 in accordance with U.S. GAAP | 645 | 705 | 5 |
| Cumulative effect of the application of SFAS No. 133, net of tax | (2) | – | – |
| Extraordinary item: | | | |
| Gain on early retirement of long-term debt, net of tax | – | 13 | – |
| Net income in accordance with U.S. GAAP | 643 | 718 | 5 |

### COMPREHENSIVE INCOME IN ACCORDANCE WITH U.S. GAAP

**Year ended December 31** (millions of dollars)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| Net income in accordance with U.S. GAAP | 643 | 718 | 5 |
| Adjustments affecting comprehensive income under U.S. GAAP | | | |
| Foreign currency translation adjustment | – | (5) | 3 |
| Additional minimum liability for employee future benefits (SFAS No. 87), net of tax[7] | (56) | – | – |
| Unrealized loss on derivatives, net of tax[2] | (5) | – | – |
| Comprehensive income before cumulative effect of the application of SFAS No. 133 in accordance with U.S. GAAP | 582 | 713 | 8 |
| Cumulative effect of the application of SFAS No. 133, net of tax[2] | (4) | – | – |
| Comprehensive income in accordance with U.S. GAAP | 578 | 713 | 8 |

**CONDENSED BALANCE SHEET**[8]

**December 31** (millions of dollars)

| | 2001 | 2000 |
|---|---|---|
| Current assets | 1,053 | 1,767 |
| Current assets of discontinued operations | 113 | 3,466 |
| Unrealized gains on energy trading contracts | 365 | 379 |
| Long-term investments | 1,434 | 1,354 |
| Plant, property and equipment | 15,391 | 15,248 |
| Regulatory asset[9] | 2,613 | 3,670 |
| Other assets | 210 | 103 |
| Long-term assets of discontinued operations | 212 | 1,197 |
| | 21,391 | 27,184 |
| Current liabilities[10] | 1,731 | 2,102 |
| Provision for loss on discontinued operations | 264 | 76 |
| Current liabilities of discontinued operations | 116 | 3,877 |
| Unrealized losses on energy trading contracts | 112 | 170 |
| Deferred amounts | 437 | 328 |
| Long-term debt | 9,512 | 9,928 |
| Deferred income taxes[9] | 2,555 | 3,412 |
| Preferred securities[11] | 694 | 994 |
| Trust originated preferred securities | 218 | 218 |
| Long-term liabilities of discontinued operations | 9 | 528 |
| Shareholders' equity | 5,743 | 5,551 |
| | 21,391 | 27,184 |

7 Under U.S. GAAP, a net loss recognized pursuant to SFAS No. 87 "Employers' Accounting for Pensions" as an additional pension liability not yet recognized as net period pension cost, must be recorded as a component of comprehensive income.
8 In accordance with U.S. GAAP, the condensed Statement of Consolidated Income and Balance Sheet are prepared using the equity method of accounting for joint ventures. Excluding the impact of other U.S. GAAP adjustments, the use of the proportionate consolidation method of accounting for joint ventures, as required under Canadian GAAP, results in the same net income and Shareholders' Equity.
9 Under U.S. GAAP, the Company is required to record a deferred income tax liability for its cost-of-service regulated businesses. As these deferred income taxes are recoverable through future revenues, a corresponding regulatory asset is recorded for U.S. GAAP purposes.
10 Current liabilities include dividends payable of $114 million (2000 – $103 million) and current taxes payable of $149 million (2000 – $169 million).
11 Under U.S. GAAP, the Preferred Securities are classified as a liability. The fair value of the Preferred Securities at December 31, 2001 is $740 million (2000 – $974 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)

| | 2001 | 2000 |
|---|---|---|
| **Deferred Tax Liabilities** | | |
| Accelerated tax depreciation on plant and equipment | 1,722 | 2,030 |
| Taxes on future revenue requirement | 897 | 1,610 |
| Undistributed earnings of subsidiaries and joint ventures | 318 | 250 |
| Other | 14 | 38 |
| | 2,951 | 3,928 |
| **Deferred Tax Assets** | | |
| Net operating and capital loss carryforwards | 180 | 292 |
| Deferred amounts | 140 | 155 |
| Other | 101 | 94 |
| | 421 | 541 |
| Less: Valuation allowance | 25 | 25 |
| | 396 | 516 |
| Net deferred tax liabilities | 2,555 | 3,412 |

**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 SFAS No. 123 "Accounting for Stock-Based Compensation" would have resulted in net income/(loss) of $638 million in 2001 (2000 – $714 million; 1999 – $(13) million) and net income/(loss) per share of $1.29 in 2001 (2000 – $1.43; 1999 – $(0.14)).

**OTHER**

In July 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141 "Business Combinations", and SFAS No. 142 "Goodwill and Other Intangible Assets". The CICA has issued standards that are substantially similar to SFAS No. 141 and No. 142. These standards require that the purchase method of accounting be used for all future business combinations. Goodwill resulting from business combinations will not be amortized but will be tested for impairment on at least an annual basis. The initial adoption of the new standard on January 1, 2002 is not expected to have a significant impact on any amounts recorded in the Company's financial statements.

In June 2001, the FASB issued SFAS No. 143 "Accounting for Asset Retirement Obligations", which addresses financial accounting and reporting for obligations associated with asset retirement costs. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset. The liability is accreted at the end of each period through charges to operating expenses. The Company is required and plans to adopt the provisions of SFAS No. 143 for the quarter ending March 31, 2003. The Company has not yet estimated the impact of adopting this standard.

In October 2001, the FASB issued SFAS No. 144 "Accounting for the Impairment or Disposal of Long-term Assets", which addresses the financial accounting and reporting for the impairment or disposal of long-lived assets. SFAS No. 144 supercedes but retains the basic principles of SFAS No. 121 for the impairment of assets to be held and used. Assets classified as held for sale will be measured at the lower of their carrying amount or fair value less cost to sell, and depreciation will cease when the asset or group is classified as held for sale. SFAS No. 144 broadens the definition of disposals to be presented as discontinued operations. The Company will be required to adopt the provisions of SFAS No. 144 on a prospective basis for the period beginning January 1, 2002 and will not result in the restatement of income for 2001 or prior periods.

# SUPPLEMENTARY INFORMATION

## SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

The following sets forth selected quarterly financial data for the four quarters of 2001 and 2000 in millions of dollars except for per share amounts.

**Three months ended** (unaudited)

| | March 31 | June 30 | September 30 | December 31 |
|---|---|---|---|---|
| **2001** | | | | |
| **OPERATING RESULTS** | | | | |
| Revenues | 1,356 | 1,319 | 1,297 | 1,277 |
| Net income | | | | |
| Continuing operations before unusual items | 174 | 166 | 163 | 167 |
| Continuing operations | 174 | 166 | 163 | 167 |
| Net income applicable to common shares | 166 | 87 | 163 | 187 |
| **SHARE STATISTICS** | | | | |
| Net income per share | | | | |
| Continuing operations before unusual items | $ 0.37 | $ 0.35 | $ 0.34 | $ 0.35 |
| Continuing operations | $ 0.37 | $ 0.35 | $ 0.34 | $ 0.35 |
| Net income applicable to common shares – Basic and Diluted | $ 0.35 | $ 0.18 | $ 0.34 | $ 0.40 |
| **2000** | | | | |
| **OPERATING RESULTS** | | | | |
| Revenues | 1,132 | 1,075 | 1,120 | 1,094 |
| Net income | | | | |
| Continuing operations before unusual items | 136 | 129 | 151 | 176 |
| Continuing operations | 172 | 129 | 158 | 191 |
| Net income applicable to common shares | 178 | 132 | 239 | 162 |
| **SHARE STATISTICS** | | | | |
| Net income per share | | | | |
| Continuing operations before unusual items | $ 0.29 | $ 0.27 | $ 0.32 | $ 0.37 |
| Continuing operations | $ 0.37 | $ 0.27 | $ 0.33 | $ 0.40 |
| Net income applicable to common shares – Basic and Diluted | $ 0.38 | $ 0.28 | $ 0.50 | $ 0.34 |

## 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**

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| Ratio of earnings to fixed charges[1] | 2.2 | 2.0 | 1.6 |

[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**

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| Ratio of earnings to fixed charges | 2.0 | 2.0 | 1.5 |

Differences are described in Note 20 "Significant Differences Between Canadian and U.S. GAAP", to the Consolidated Financial Statements.

# SUPPLEMENTARY INFORMATION

## THREE-YEAR FINANCIAL HIGHLIGHTS

(millions of dollars, except where indicated)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| **Operating results** | | | |
| Revenues | 5,249 | 4,421 | 4,239 |
| Net income/(loss) | | | |
| Continuing operations before unusual items | 737 | 671 | 613 |
| Continuing operations after unusual items | 737 | 729 | 552 |
| Discontinued operations | (67) | 61 | (534) |
| Net income | 670 | 790 | 18 |
| Net income/(loss) applicable to common shares | 603 | 711 | (80) |
| **Assets** | | | |
| Plant, property and equipment | | | |
| Alberta System | 5,018 | 5,180 | 5,283 |
| Canadian Mainline | 8,954 | 9,202 | 9,386 |
| North American pipelines and other transmission | 2,514 | 2,445 | 2,513 |
| Power | 1,297 | 771 | 492 |
| Other | 66 | 111 | 52 |
| Total assets | | | |
| Continuing operations | 19,766 | 20,492 | 19,520 |
| Discontinued operations | 325 | 5,056 | 5,449 |
| **Capitalization** | | | |
| Long-term debt | 9,347 | 9,928 | 11,591 |
| Non-recourse debt of joint ventures | 1,295 | 1,296 | 1,272 |
| Junior subordinated debentures | 237 | 243 | 241 |
| Preferred securities | 675 | 969 | 960 |
| Preferred shares | 389 | 389 | 717 |
| Common shareholders' equity | 5,429 | 5,230 | 4,935 |
| **Cash flow data** | | | |
| Funds generated from continuing operations | 1,514 | 1,283 | 1,041 |
| Capital expenditures | | | |
| Continuing operations | 440 | 518 | 1,323 |
| Discontinued operations | 52 | 294 | 501 |
| **Share statistics** | | | |
| Net income/(loss) per share | | | |
| Continuing operations before unusual items | $ 1.41 | $ 1.25 | $ 1.07 |
| Continuing operations after unusual items | $ 1.41 | $ 1.37 | $ 0.94 |
| Discontinued operations | $ (0.14) | $ 0.13 | $ (1.13) |
| Net income/(loss) applicable to common shares – Basic and Diluted | $ 1.27 | $ 1.50 | $ (0.19) |
| Funds generated from continuing operations per share | $ 3.18 | $ 2.70 | $ 2.22 |
| **Registered common shareholders, December 31** | 36,350 | 30,758 | 32,328 |
| | | | |
| **U.S. GAAP information** | | | |
| Net income/(loss) | | | |
| Continuing operations before unusual and extraordinary items | 682 | 614 | 552 |
| Continuing operations before extraordinary item | 710 | 644 | 491 |
| Discontinued operations | (67) | 61 | (486) |
| Extraordinary item | – | 13 | – |
| Net income applicable to common shares | 643 | 718 | 5 |
| Net income/(loss) per share | | | |
| Continuing operations before unusual and extraordinary items | $ 1.39 | $ 1.22 | $ 1.04 |
| Continuing operations before extraordinary item | $ 1.45 | $ 1.28 | $ 0.91 |
| Discontinued operations | $ (0.14) | $ 0.13 | $ (1.03) |
| Extraordinary item | $ – | $ 0.03 | $ – |
| Net income/(loss) applicable to common shares – Basic and Diluted | $ 1.31 | $ 1.44 | $ (0.12) |
| Common shareholders' equity | 5,354 | 5,162 | 4,897 |

# INVESTOR INFORMATION

#### STOCK EXCHANGES AND SYMBOLS

Common shares are listed on the Toronto and New York stock exchanges under the symbol: TRP

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

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

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

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

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

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

#### ANNUAL MEETING

The annual meeting of shareholders is scheduled for April 26, 2002 at 10:30 AM (Mountain Daylight Time) at the RoundUp Centre, Calgary, Alberta.

#### IMPORTANT DATES

Scheduled common share dividend payment dates in 2002 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.

A registered holder will become a participant in the plan as of the first dividend record date following receipt by our Plan Agent, Computershare Trust Company of Canada, of a properly executed authorization form. Dividend record dates for common and preferred shares are generally the last business day of each March, June, September and December.

Participants may also make optional cash payments to buy additional shares of up to $10,000 (US$7,000) per quarter. Participants wishing to make such optional cash payments must ensure that their optional cash payment is received by our Plan Agent, on or prior to the common share dividend payment date. Our common share dividend payment dates are noted above under "Important Dates".

#### 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. Commencing January 1, 2001, the U.S. Internal Revenue Service (IRS) has required 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).

#### 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.)
- 8.25% Preferred Securities

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

## INVESTOR INFORMATION

#### 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%: The Bank of New York (New York).

#### 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: The Bank of New York (New York) (unsubordinated notes).

#### NGTL U.S. MEDIUM TERM NOTES

Trustee: U.S. Bank Trust National Association

### CORPORATE GOVERNANCE

Please refer to TransCanada's Notice of 2002 Annual Meeting of Common Shareholders and Management Proxy Circular for the Company's report on Corporate Governance.

### INFORMATION RESOURCES

#### ANNUAL INFORMATION FORM

TransCanada's 2001 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.

## INVESTOR INFORMATION

**SHAREHOLDER ASSISTANCE**

If you are currently a registered shareholder and would like to:

- change your address
- eliminate multiple mailings
- request information regarding cheques, share certificates, stock transfers or dividend reinvestment plan account updates

Please contact our transfer agent in writing, by phone or e-mail at:

**Computershare Trust Company of Canada**
Equity Transfer Services
600, 530 – 8 Avenue SW
Calgary, Alberta, Canada T2P 3S8
Telephone: (403) 267-6555
Toll-free: 1-888-267-6555
E-mail: caregistryinfo@computershare.com

If you are a beneficial shareholder (your shares are held by your broker in the name of the brokerage house), questions should be directed to your broker on all administrative matters. If you would like to receive quarterly reports, please write, call or e-mail Computershare Trust Company of Canada with your name and address.

**WWW.TRANSCANADA.COM**

To access TransCanada's corporate and financial information, including quarterly reports, real-time conference call webcasts, and news releases, visit our Internet site at www.transcanada.com.

**TRP PERFORMANCE**

**COMMON SHARE PRICE RANGE**

| Toronto Stock Exchange | High | Low |
|---|---|---|
| First Quarter 2001 | 19.52 | 14.85 |
| Second Quarter 2001 | 19.35 | 17.50 |
| Third Quarter 2001 | 21.13 | 18.45 |
| Fourth Quarter 2001 | 20.95 | 18.71 |
| **New York Stock Exchange (US dollars)** | | |
| First Quarter 2001 | 12.48 | 9.88 |
| Second Quarter 2001 | 12.68 | 11.32 |
| Third Quarter 2001 | 13.41 | 12.17 |
| Fourth Quarter 2001 | 13.40 | 11.91 |

**METRIC CONVERSION TABLE**

| Metric | Imperial | Factor |
|---|---|---|
| kilometres | miles | 0.62 |
| millimetres | inches | 0.04 |
| gigajoules | million British thermal units | 0.95 |
| cubic metres* | cubic feet | 35.3 |
| degrees Celsius | degrees Fahrenheit | (i) multiply by 1.8, then add 32 degrees (ii) 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

(as at February 26, 2002)

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

**Harold (Hal) Kvisle**
President and CEO
TransCanada PipeLines Limited
Calgary, Alberta

**Douglas D. Baldwin,** P.ENG.
Corporate Director
Calgary, Alberta

**Ronald B. Coleman**
President, R. B. Coleman Consulting Co. Ltd.
Calgary, Alberta

**Wendy Dobson**
Professor, Rotman School of Management and
Director, Institute for International Business,
University of Toronto
Toronto, Ontario

**The Hon. Paule Gauthier,** P.C., O.C., O.Q., Q.C.*
Senior Partner, Desjardins Ducharme Stein Monast
Québec, Québec

**Kerry L. Hawkins**
President, Cargill Limited
Winnipeg, Manitoba

**The Hon. Donald S. Macdonald,** P.C., C.C.**
Corporate Director
Toronto, Ontario

**David P. O'Brien*****
Chairman and Chief Executive Officer,
PanCanadian Energy Corporation
Calgary, Alberta

**James R. Paul**
Chairman, James and Associates
Kingwood, Texas

**Harry G. Schaefer,** F.C.A.
President, Schaefer & Associates Ltd. and
Vice Chairman, TransCanada PipeLines Limited
Calgary, Alberta

**W. Thomas Stephens**
Corporate Director
Greenwood Village, Colorado

**Joseph D. Thompson,** P. ENG.
Chairman, PCL Construction Group Inc.
Edmonton, Alberta

*Appointed January 29, 2002
**Not standing for re-election
***Appointed October 31, 2001

# CORPORATE INFORMATION

## EXECUTIVE OFFICERS

(as at February 26, 2002)

**Harold N. Kvisle**
President and Chief Executive Officer

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

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

**Dennis J. McConaghy**
Executive Vice-President, Gas Development

**Alexander J. Pourbaix**
Executive Vice-President, Power Development

**Sarah E. Raiss**
Executive Vice-President, Corporate Services

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

There were three senior appointments in 2001. Harold N. Kvisle was named President and Chief Executive Officer and a member of the Board of Directors in April 2001. Mr. Kvisle joined the company in 1999 as Executive Vice-President, Trading and Business Development, and led the company's divestiture program. Dennis J. McConaghy was appointed Executive Vice-President, Gas Development; and Alexander J. Pourbaix was appointed Executive Vice-President, Power Development.

We would also like to take this opportunity to thank Walentin (Val) Mirosh, who retired from TransCanada at the end of 2001. Mr. Mirosh was instrumental in moving TransCanada forward on many fronts, including corporate strategy, northern development and the evolution of our regulatory framework.

## TRANSCANADA IN THE COMMUNITY

TransCanada also publishes annual reports on its Community Investment; Health, Safety and Environment; and greenhouse gas emissions programs. Copies of the following reports are available at **www.transcanada.com:**

***Community Investment, Year in Review***
***Health, Safety and Environment Annual Report***
***Submission to the Climate Change Voluntary Challenge and Registry***

If you would like to receive a copy of any of these reports by mail, please contact

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

Designed and produced by **Sutton Javelin Corporate Communications,** Calgary. Printed by **Sundog Printing Limited,** Calgary. Printed on recycled paper.

TransCanada

*In business to deliver* ™


TransCanada PipeLines Limited
TransCanada Tower
450 – 1st Street SW
Calgary, Alberta T2P 5H1
(403) 920-2000


TransCanada welcomes questions
from shareholders and 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