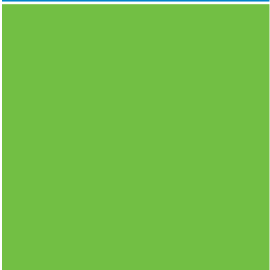




RESTATED 2004 CONSOLIDATED FINANCIAL STATEMENTS



## AUDITORS' REPORT

### To the Shareholders of TransCanada Corporation

We have audited the consolidated balance sheets of TransCanada Corporation as at December 31, 2004 and 2003 and the consolidated statements of income, retained earnings and cash flows for the years in the three-year period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these revised consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2004 in accordance with Canadian generally accepted accounting principles.

Our previous report dated February 28, 2005 has been withdrawn and the financial statements have been revised as explained in note 22 to the revised consolidated financial statements.



**Chartered Accountants**

Calgary, Canada

February 28, 2005, except as to note 22 which is as of July 28, 2005

## CONSOLIDATED INCOME

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

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

## CONSOLIDATED CASH FLOWS

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

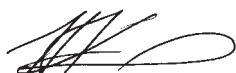
The accompanying notes to the consolidated financial statements are an integral part of these statements.

## CONSOLIDATED BALANCE SHEET

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

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)	2004	2003	2002
Balance at beginning of year	<b>1,185</b>	854	586
Net income	<b>1,032</b>	851	747
Common share dividends	<b>(562)</b>	(520)	(479)
	<b>1,655</b>	1,185	854

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

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

### GAS TRANSMISSION

The Gas Transmission segment owns and operates the following natural gas pipelines:

- a natural gas transmission system extending from the Alberta border east into Québec (the Canadian Mainline);
- a natural gas transmission system in Alberta (the Alberta System);
- a natural gas transmission system extending from the British Columbia/Idaho border to the Oregon/California border, traversing Idaho, Washington and Oregon (the Gas Transmission Northwest System);
- a natural gas transmission system extending from central Alberta to the B.C., Saskatchewan and the United States borders (the Foothills System);
- a natural gas transmission system extending from the Alberta border west into southeastern B.C. (the BC System);
- a natural gas transmission system extending from a point near Ehrenberg, Arizona to the Baja California, Mexico/California border (the North Baja System); and
- natural gas transmission systems in Alberta which supply natural gas to the oil sands region of northern Alberta and to a petrochemical complex at Joffre, Alberta (Ventures LP).

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

### POWER

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

### NOTE 1 Accounting Policies

The consolidated financial statements of the Company have been prepared by Management in accordance with Canadian generally accepted accounting principles (GAAP). These accounting principles are different in some respects from U.S. GAAP and the significant differences are described in Note 22. Amounts are stated in Canadian dollars unless otherwise indicated. Certain comparative figures have been reclassified to conform with the current year's presentation.

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

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

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

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

**Regulation** The Canadian Mainline, the BC System, the Foothills System, and Trans Québec & Maritimes Pipeline Inc. (Trans Québec & Maritimes) are subject to the authority of the National Energy Board (NEB) and the Alberta System is regulated by the Alberta Energy and Utilities Board (EUB). These Canadian natural gas transmission operations are regulated with respect to the determination of revenues, tolls, construction and operations. The NEB approved interim tolls for 2004 for the Canadian Mainline. The tolls will remain interim pending a decision on Phase II of the 2004 Tolls and Tariff Application, which will address capital structure, for the Canadian Mainline. Any adjustments to the interim tolls will be recorded in accordance with the NEB decision. The Gas Transmission Northwest System, the North Baja System and the other natural gas pipelines in the U.S. are subject to the authority of the Federal Energy Regulatory Commission (FERC). In order to appropriately reflect the economic impact of the regulators' decisions regarding the Company's revenues and tolls, and to thereby achieve a proper matching of revenues and expenses, the timing of recognition of certain revenues and expenses in these regulated businesses may differ from that otherwise expected under GAAP.

**Cash and Short-Term Investments** The Company's short-term investments with original maturities of three months or less are considered to be cash equivalents and are recorded at cost, which approximates market value.

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

#### **Plant, Property and Equipment**

**Gas Transmission** Plant, property and equipment of natural gas transmission operations are carried at cost. Depreciation is calculated on a straight-line basis. Pipeline and compression equipment are depreciated at annual rates ranging from two to six per cent and metering and other plant are depreciated at various rates. An allowance for funds used during construction, using the rate of return on rate base approved by the regulators, is capitalized and included in the cost of gas transmission plant.

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

**Corporate** Corporate plant, property and equipment are recorded at cost and depreciated on a straight-line basis over estimated useful lives at average annual rates ranging from three to 20 per cent.

**Power Purchase Arrangements** Power purchase arrangements (PPAs) are long-term contracts to purchase or sell power on a predetermined basis. The initial payments for PPAs acquired by TransCanada are deferred and amortized over the terms of the contracts, from the dates of acquisition, which range from eight to 23 years. Certain PPAs under which TransCanada sells power are accounted for as operating leases and, accordingly, the related plant, property and equipment are accounted for as assets under operating leases.

**Stock Options** TransCanada's Stock Option Plan permits the award of options to purchase the Company's common shares to certain employees, some of whom are officers. The contractual life of options granted prior to 2003 is ten years and for options granted in 2003 and subsequently, the contractual life is seven years. Options may be exercised at a price determined at the time the option is awarded. Generally, for awards granted prior to 2003, 25 per cent of the options vest on the award date and 25 per cent on each of the three following award date anniversaries. For awards granted subsequent to 2002, no options vest on the award date and 33.3 per cent vest on each of the three following award date anniversaries. Effective January 1, 2002, TransCanada adopted the fair value method of accounting for stock options. The Company is recording compensation expense over the three year vesting period. This charge is reflected in the Gas Transmission and Power segments.



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

Canadian income taxes are not provided on the unremitted earnings of foreign investments as the Company does not intend to repatriate these earnings in the foreseeable future.

**Foreign Currency Translation** Most of the Company's foreign operations are self-sustaining and are translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated at period end exchange rates and items included in the statements of consolidated income, consolidated retained earnings and consolidated cash flows are translated at the exchange rates in effect at the time of the transaction. Translation adjustments are reflected in the foreign exchange adjustment in Shareholders' Equity.

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

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

**Derivative Financial Instruments** The Company utilizes derivative and other financial instruments to manage its exposure to changes in foreign currency exchange rates, interest rates and energy commodity prices. Gains or losses relating to derivatives that are hedges are deferred and recognized in the same period and in the same financial statement category as the corresponding hedged transactions. The recognition of gains and losses on derivatives used as hedges for Canadian Mainline, Alberta System, GTN and the Foothills System exposures is determined through the regulatory process.

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

**Employee Benefit and Other Plans** The Company sponsors defined benefit pension plans (DB Plans). The cost of defined benefit pensions and other post-employment benefits earned by employees is actuarially determined using the projected benefit method pro-rated on service and Management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market-related values based on a five-year moving average value for all plan assets. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The excess of the net actuarial gain or loss over 10 per cent of the greater of the benefit obligation and the fair value of plan assets is amortized over the average remaining service period of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. The Company previously sponsored two additional plans, a defined contribution plan and a combination of the defined benefit and defined contribution plans, which were effectively terminated at December 31, 2002.

The Company has broad-based, medium-term employee incentive plans, which grant units to each eligible employee. Under these plans, units vest when certain conditions are met, including the employee's continued employment during a specified period and achievement of specified corporate performance targets. The units under one of these incentive plans vested at the end of 2004 and the Company recorded compensation expense over the three year vesting period. The value of units under this plan, net of income tax, will be paid in cash in 2005.

## NOTE 2 Accounting Changes

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

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

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

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

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

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

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

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

**NOTE 3 Segmented Information****Net Income/(Loss) <sup>(1)</sup>**

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

Year ended December 31, 2003 (millions of dollars)

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

Year ended December 31, 2002 (millions of dollars)

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

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

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

**Total Assets**

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

**Geographic Information**

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

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

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

**Plant, Property and Equipment**

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

**Capital Expenditures**

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

**NOTE 4 Plant, Property and Equipment**

December 31 (millions of dollars)

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

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

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

**NOTE 5 Other Assets**

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

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

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

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

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

**NOTE 6 Joint Venture Investments**

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

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

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

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

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

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

**Summarized Financial Information of Joint Ventures**

Year ended December 31 (millions of dollars)	2004	2003	2002
<b>Income</b>			
Revenues	559	623	680
Other costs and expenses	(238)	(275)	(251)
Depreciation	(88)	(96)	(119)
Financial charges and other	(26)	(43)	(58)
Proportionate share of income before income taxes of joint ventures	207	209	252
<hr/>			
Year ended December 31 (millions of dollars)	2004	2003	2002
<b>Cash Flows</b>			
Operations	269	272	323
Investing activities	(179)	(114)	(124)
Financing activities	(76)	(156)	(210)
Effect of foreign exchange rate changes on cash and short-term investments	(5)	(10)	(1)
Proportionate share of increase/(decrease) in cash and short-term investments of joint ventures	9	(8)	(12)
<hr/>			
December 31 (millions of dollars)	2004	2003	
<b>Balance Sheet</b>			
Cash and short-term investments	64	55	
Other current assets	133	106	
Long-term investments	105	118	
Plant, property and equipment	1,644	1,693	
Other assets and deferred amounts (net)	221	109	
Current liabilities	(153)	(94)	
Non-recourse debt	(779)	(761)	
Future income taxes	(49)	(51)	
Proportionate share of net assets of joint ventures	1,186	1,175	

**NOTE 7 Long-Term Investments**

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

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

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

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

**NOTE 8 Acquisitions and Dispositions****Acquisitions**

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

**Purchase Price Allocation**

(millions of U.S. dollars)

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

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

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



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

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

**Purchase Price Allocation**

(millions of dollars)

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

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

**Dispositions**

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

At a special meeting held on April 29, 2004, Power LP's unitholders approved an amendment to the terms of the Power LP Partnership Agreement to remove Power LP's obligation to redeem all units not owned by TransCanada at June 30, 2017. TransCanada was required to fund this redemption, thus the removal of Power LP's obligation eliminates this requirement. The removal of the obligation and the reduction in TransCanada's ownership interest in Power LP resulted in a gain of \$172 million. This amount includes the recognition of unamortized gains of \$132 million on previous Power LP transactions.

**NOTE 9 Long-Term Debt**

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

- (1) Amounts outstanding are stated in millions of Canadian dollars; amounts denominated in currencies other than Canadian dollars are stated in millions.
- (2) Weighted average interest rates are stated as at the respective outstanding dates. The effective weighted average interest rates resulting from swap agreements are as follows: Foothills senior unsecured notes in 2003 – 5.8 per cent; Portland senior secured notes in 2003 – 6.2 per cent; Other U.S. dollar subordinated debentures – 9.0 per cent (2003 – 9.0 per cent); and Other U.S. dollar unsecured loans, debentures and notes – 5.2 per cent (2003 – 5.2 per cent).
- (3) Long-term debt of TCPL.
- (4) Long-term debt of NOVA Gas Transmission Ltd. excluding a \$241 million note held by TCPL (2003 – \$258 million).
- (5) Long-term debt of Gas Transmission Northwest Corporation.
- (6) Long-term debt of Portland.
- (7) Long-term debt of TCPL, excluding \$85 million held by OSP Finance Company and \$14 million held by TC Ocean State Corporation.
- (8) See Note 2, Accounting Changes – “Generally Accepted Accounting Principles”.

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

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

## CANADIAN MAINLINE

**First Mortgage Pipe Line Bonds** The Deed of Trust and Mortgage securing the Company's First Mortgage Pipe Line Bonds limits the specific and floating charges to those assets comprising the present and future Canadian Mainline and TCPL's present and future gas transportation contracts.

## ALBERTA SYSTEM

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

**Medium-Term Notes** Medium-term notes amounting to \$50 million have a provision entitling the holders to extend the maturity of the medium-term notes from the initial repayment date of 2007 to 2027. If extended, the interest rate would increase from 6.1 per cent to 7.0 per cent and the medium-term notes would become redeemable at the option of the Company.

## GAS TRANSMISSION NORTHWEST CORPORATION

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

## OTHER

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

## Financial Charges

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

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

**NOTE 10 Non-Recourse Debt of Joint Ventures**

		2004		2003	
	Maturity Dates	Outstanding December 31 <sup>(1)</sup>	Weighted Average Interest Rate <sup>(2)</sup>	Outstanding December 31 <sup>(1)</sup>	Weighted Average Interest Rate <sup>(2)</sup>
<b>Great Lakes</b>					
Senior Unsecured Notes (2004 – US\$235; 2003 – US\$240)	2011 to 2030	283	7.9%	310	7.9%
<b>Iroquois</b>					
Senior Unsecured Notes (2004 and 2003 – US\$151)	2010 to 2027	182	7.5%	196	7.5%
Bank Loan (2004 – US\$36; 2003 – US\$43)	2008	43	2.5%	56	2.3%
<b>Trans Québec &amp; Maritimes</b>					
Bonds	2005 to 2010	143	7.3%	143	7.3%
Term Loan	2006	29	3.2%	34	3.5%
<b>TransCanada Power, L.P.</b>					
Senior Unsecured Notes (2004 – US\$58)	2014	70	5.9%	–	–
Credit Facility	2009	64	3.2%	–	–
Term Loan	2010	2	11.3%	–	–
<b>Other</b>	2005 to 2012	46	4.9%	41	5.4%
		<b>862</b>		<b>780</b>	
Less: Current Portion of Non-Recourse Debt of Joint Ventures		<b>83</b>		<b>19</b>	
		<b>779</b>		<b>761</b>	

(1) Amounts outstanding represent TransCanada's proportionate share and are stated in millions of Canadian dollars; amounts denominated in U.S. dollars are stated in millions.

(2) Weighted average interest rates are stated as at the respective outstanding dates. At December 31, 2004, the effective weighted average interest rates resulting from swap agreements are as follows: Iroquois bank loan – 4.1 per cent (2003 – 4.5 per cent) and Power LP Credit Facility – 5.2 per cent.

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

The Company's proportionate share of principal repayments resulting from maturities and sinking fund obligations of the non-recourse joint venture debt approximates: 2005 – \$83 million; 2006 – \$49 million; 2007 – \$18 million; 2008 – \$18 million; and 2009 – \$141 million.

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

**NOTE 11 Deferred Amounts**

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

**NOTE 12 Non-Controlling Interests and Preferred Securities**

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

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

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

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

**Preferred Securities of Subsidiary**

The US\$460 million 8.25 per cent preferred securities of TCPL (Preferred Securities) are redeemable by the issuer at par at any time. The issuer may elect to defer interest payments on the Preferred Securities and settle the deferred interest in either cash or common shares.

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

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

**Preferred Shares of Subsidiary**

December 31	Number of Shares (thousands)	Dividend Rate Per Share	Redemption Price Per Share	2004	2003
				(millions of dollars)	
<b>Cumulative First Preferred Shares of Subsidiary</b>					
Series U	4,000	\$2.80	\$50.00	195	195
Series Y	4,000	\$2.80	\$50.00	194	194
				<b>389</b>	<b>389</b>

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

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

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

**NOTE 13 Common Shares**

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

**Common Shares Issued and Outstanding** The Company is authorized to issue an unlimited number of common shares of no par value.

**Net Income Per Share** Basic and diluted earnings per share are calculated based on the weighted average number of common shares outstanding during the year of 484.1 million and 486.7 million (2003 – 481.5 million and 483.9 million; 2002 – 478.3 million and 480.7 million), respectively. The increase in the weighted average number of shares for the diluted earnings per share calculation is due to the options exercisable under TransCanada's Stock Option Plan.

**Stock Options**

	Number of Options	Weighted Average Exercise Prices	Options Exercisable
	(thousands)		(thousands)
Outstanding at January 1, 2002	14,450	\$18.42	11,376
Granted	1,946	\$21.43	
Exercised	(2,871)	\$17.18	
Cancelled or expired	(633)	\$23.16	
Outstanding at December 31, 2002	12,892	\$18.92	10,258
Granted	1,503	\$22.42	
Exercised	(3,698)	\$17.59	
Cancelled or expired	(342)	\$24.07	
Outstanding at December 31, 2003	10,355	\$19.73	7,588
Granted	<b>1,331</b>	<b>\$26.85</b>	
Exercised	<b>(1,714)</b>	<b>\$18.42</b>	
Cancelled or expired	<b>(7)</b>	<b>\$24.25</b>	
<b>Outstanding at December 31, 2004</b>	<b>9,965</b>	<b>\$20.90</b>	<b>7,239</b>

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

Range of Exercise Prices	Options Outstanding			Options Exercisable	
	Number of Options	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
	(thousands)	(years)		(thousands)	
\$10.03 to \$17.08	1,068	5.0	\$11.68	1,068	\$11.68
\$18.01 to \$19.00	1,508	6.0	\$18.15	1,508	\$18.15
\$19.16 to \$20.58	1,477	4.0	\$20.11	1,477	\$20.11
\$20.59 to \$21.86	1,980	7.0	\$21.41	1,550	\$21.41
\$22.33 to \$22.85	1,493	5.1	\$22.35	548	\$22.39
\$24.49 to \$25.53	1,108	3.2	\$24.59	1,080	\$24.56
\$26.85	1,331	6.2	\$26.85	8	\$26.85
	9,965	5.2	\$20.90	7,239	\$19.58

At December 31, 2004, an additional five million common shares have been reserved for future issuance under TransCanada's Stock Option Plan. In 2004, TransCanada issued 1,330,860 options to purchase common shares at an average price of \$26.85 under the Company's Stock Option Plan and the weighted average fair value of each option was determined to be \$2.85. The Company used the Black-Scholes model for these calculations with the weighted average assumptions being four years of expected life, 3.3 per cent interest rate, 18 per cent volatility and 4.3 per cent dividend yield. The amount expensed for stock options, with a corresponding increase in contributed surplus for the year ended December 31, 2004, was \$3 million (2003 and 2002 – \$2 million).

**Shareholder Rights Plan** The Company's Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Under certain circumstances, each common share is entitled to one right which entitles certain holders to purchase common shares of the Company at 50 per cent of the then market price.

#### NOTE 14 Risk Management and Financial Instruments

The Company issues short-term and long-term debt, including amounts in foreign currencies, purchases and sells energy commodities and invests in foreign operations. These activities result in exposures to interest rates, energy commodity prices and foreign currency exchange rates. The Company uses derivatives to manage the risk that results from these activities.

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

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

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

**Credit Risk** Credit risk results from the possibility that a counterparty to a derivative in which the Company has an unrealized gain fails to perform according to the terms of the contract. Credit exposure is minimized through the use of established credit management techniques, including formal assessment processes, contractual and collateral requirements, master netting arrangements and credit exposure limits. At December 31, 2004, for foreign currency and interest rate derivatives, total credit risk and the largest credit exposure to a single counterparty were \$127 million and \$40 million, respectively. At December 31, 2004, for power, natural gas and heat rate derivatives, total credit risk and the largest credit exposure to a single counterparty were \$19 million and \$7 million, respectively.

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

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

**Net Investment in Foreign Assets**

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

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

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

**Reconciliation of Foreign Exchange Adjustment Gains/(Losses)**

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

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



**Foreign Exchange and Interest Rate Management Activity** The Company manages certain of the foreign exchange risk of U.S. dollar debt, U.S. dollar expenses and the interest rate exposures of the Canadian Mainline, the Alberta System, GTN and the Foothills System through the use of foreign currency and interest rate derivatives. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms. The details of the foreign exchange and interest rate derivatives are shown in the table below.

Asset/(Liability)		2004		2003	
December 31 (millions of dollars)	Accounting Treatment	Fair Value	Notional or Notional Principal Amount	Fair Value	Notional or Notional Principal Amount
<b>Foreign Exchange</b>					
Cross-currency swaps					
(maturing 2010 to 2012)	Hedge	(39)	U.S. 157	(26)	U.S. 282
<b>Interest Rate</b>					
Interest rate swaps					
Canadian dollars					
(maturing 2005 to 2008)	Hedge	7	145	(1)	340
(maturing 2006 to 2009)	Non-hedge	9	374	10	624
		<b>16</b>		<b>9</b>	
U.S. dollars					
(maturing 2010 to 2015)	Hedge	(2)	U.S. 275	11	U.S. 50
(maturing 2007 to 2009)	Non-hedge	7	U.S. 100	(3)	U.S. 50
		<b>5</b>		<b>8</b>	

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

The Company manages the foreign exchange and interest rate exposures of its other businesses through the use of foreign currency and interest rate derivatives. The details of these foreign currency and interest rate derivatives are shown in the table below.

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

In accordance with the Company's accounting policy, each of the above derivatives is recorded on the consolidated balance sheet at its fair value in 2004. At December 31, 2004, the Company also had interest rate swaps associated with the cross-currency swaps with notional principal amounts of \$136 million (2003 – \$136 million) and US\$100 million (2003 – US\$100 million). The carrying amount and fair value of these interest rate swaps was \$(10) million (2003 – nil) and \$(10) million (2003 – \$(7) million), respectively. Certain of the Company's joint ventures use interest rate derivatives to manage interest rate exposures. The Company's proportionate share of the fair value of the outstanding derivatives at December 31, 2004 was \$1 million (2003 – \$(1) million).

**Energy Price Risk Management** The Company executes power, natural gas and heat rate derivatives for overall management of its asset portfolio. Heat rate contracts are contracts for the sale or purchase of power that are priced based on a natural gas index. The fair values and notional volumes of the swap, option, forward and heat rate contracts are shown in the tables below. In accordance with the Company's accounting policy, each of the derivatives in the table below is recorded on the balance sheet at its fair value in 2004 and 2003.

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

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

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

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

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

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

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

**NOTE 15 Income Taxes****Provision for Income Taxes**

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

**Geographic Components of Income**

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

**Reconciliation of Income Tax Expense**

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

**Future Income Tax Assets and Liabilities**

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

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

**Unremitted Earnings of Foreign Investments** Income taxes have not been provided on the unremitted earnings of foreign investments which the Company does not intend to repatriate in the foreseeable future. If provision for these taxes had been made, future income tax liabilities would increase by approximately \$57 million at December 31, 2004 (2003 – \$54 million).

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

#### NOTE 16 Notes Payable

	2004		2003	
	Outstanding December 31 <small>(millions of dollars)</small>	Weighted Average Interest Rate Per Annum at December 31	Outstanding December 31 <small>(millions of dollars)</small>	Weighted Average Interest Rate Per Annum at December 31
<b>Commercial Paper</b>				
Canadian dollars	546	2.6%	367	2.7%

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

At December 31, 2004, the Company had used approximately \$61 million of its total lines of credit for letters of credit and to support its ongoing commercial arrangements. If drawn, interest on the lines of credit would be charged at prime rates of Canadian chartered and U.S. banks and at other negotiated financial bases. The cost to maintain the unused portion of the lines of credit is approximately \$2 million for the year ended December 31, 2004 (2003 – \$2 million).

#### NOTE 17 Asset Retirement Obligations

At December 31, 2004, the estimated undiscounted cash flows required to settle the asset retirement obligation with respect to Gas Transmission were \$48 million, calculated using an inflation rate of 3 per cent per annum, and the estimated fair value of this liability was \$12 million (2003 – \$2 million). The estimated cash flows have been discounted at rates ranging from 6.0 per cent to 6.6 per cent. At December 31, 2004, the expected timing of payment for settlement of the obligations ranges from 13 to 25 years. No amount has been recorded for asset retirement obligations relating to the regulated natural gas transmission operation assets as it is not possible to make a reasonable estimate of the fair value of the liability due to the indeterminate timing and scope of the asset retirements. Management believes it is reasonable to assume that all retirement costs associated with the regulated pipelines will be recovered through tolls in future periods.

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

**Reconciliation of Asset Retirement Obligations**

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

**NOTE 18 Employee Future Benefits**

The Company sponsors DB Plans that cover substantially all employees and sponsored a defined contribution pension plan (DC Plan) which was effectively terminated at December 31, 2002. Benefits provided under the DB Plans are based on years of service and highest average earnings over three consecutive years of employment, and increase annually by a portion of the increase in the Consumer Products Index. Under the DC Plan, Company contributions were based on the participating employees' pensionable earnings. As a result of the termination of the DC Plan, members of this plan were awarded retroactive service credit under the DB Plans for all years of service. In exchange for past service credit, members surrendered the accumulated assets in their DC Plan accounts to the DB Plans as at December 31, 2002. This plan amendment resulted in unamortized past service costs of \$44 million. Past service costs are amortized over the expected average remaining service life of employees, which is approximately 11 years.

The Company also provides its employees with other post-employment benefits other than pensions, including termination benefits and defined life insurance and medical benefits beyond those provided by government-sponsored plans. Effective January 1, 2003, the Company combined its previously existing other post-employment benefit plans into one plan for active employees and provided existing retirees the option of adopting the provisions of the new plan. This plan amendment resulted in unamortized past service costs of \$7 million. Past service costs are amortized over the expected average remaining life expectancy of former employees, which is approximately 19 years.

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

Total cash payments for employee future benefits for 2004, consisting of cash contributed by the Company to the DB Plans and other benefit plans was \$88 million (2003 – \$114 million).

The Company measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuation of the pension plans for funding purposes was as of January 1, 2005, and the next required valuation will be as of January 1, 2006.

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

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

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

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

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

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

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

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

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

	Pension Benefit Plans		Other Benefit Plans	
	2004	2003	2004	2003
Discount rate	<b>5.75%</b>	6.00%	<b>6.00%</b>	6.25%
Rate of compensation increase	<b>3.50%</b>	3.50%		

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

	Pension Benefit Plans			Other Benefit Plans		
	2004	2003	2002	2004	2003	2002
Discount rate	<b>6.00%</b>	6.25%	6.75%	<b>6.25%</b>	6.50%	6.85%
Expected long-term rate of return on plan assets	<b>6.90%</b>	7.25%	7.52%			
Rate of compensation increase	<b>3.50%</b>	3.75%	3.50%			

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

For measurement purposes, a 9.0 per cent annual rate of increase in the per capita cost of covered health care benefits was assumed for 2005. The rate was assumed to decrease gradually to 5.0 per cent for 2014 and remain at that level thereafter. A one percentage point increase or decrease in assumed health care cost trend rates would have the following effects.

(millions of dollars)	Increase	Decrease
Effect on total of service and interest cost components	2	(1)
Effect on post-employment benefit obligation	12	(11)

The Company's net benefit cost is as follows.

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



The Company's pension plan weighted average asset allocation at December 31, by asset category, and weighted average target allocation at December 31, by asset category, is as follows.

Asset Category	Percentage of Plan Assets		Target Allocation
	2004	2003	2004
Debt securities	44%	47%	35% to 60%
Equity securities	56%	53%	40% to 65%
	100%	100%	

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

#### NOTE 19 Changes in Operating Working Capital

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

#### NOTE 20 Commitments, Contingencies and Guarantees

**Commitments** Future annual payments, net of sub-lease receipts, under the Company's operating leases for various premises and a natural gas storage facility are approximately as follows.

Year ended December 31 (millions of dollars)	Minimum Lease Payments	Amounts Recoverable under Sub-Leases	Net Payments
2005	37	(9)	28
2006	45	(10)	35
2007	51	(9)	42
2008	53	(9)	44
2009	53	(9)	44

The operating lease agreements for premises expire at various dates through 2011, with an option to renew certain lease agreements for five years. The operating lease agreement for the natural gas storage facility expires in 2030 with lessee termination rights every fifth anniversary commencing in 2010 and with the lessor having the right to terminate the agreement every five years commencing in 2015. Net rental expense on operating leases for the year ended December 31, 2004 was \$7 million (2003 – \$2 million; 2002 – \$7 million).

On June 18, 2003, the Mackenzie Delta gas producers, the Aboriginal Pipeline Group (APG) and TransCanada reached an agreement which governs TransCanada's role in the Mackenzie Gas Pipeline Project. The project would result in a natural gas pipeline being constructed from Inuvik, Northwest Territories, to the northern border of Alberta, where it would connect with the Alberta System. Under the agreement, TransCanada agreed to finance the APG for its one-third share of project development costs. This share is currently estimated to be approximately \$90 million. As at December 31, 2004, TransCanada had funded \$60 million of this loan (2003 – \$34 million) which is included in other assets. The ability to recover this investment is dependent upon the outcome of the project.

**Contingencies** The Canadian Alliance of Pipeline Landowners' Associations and two individual landowners commenced an action in 2003 under Ontario's Class Proceedings Act, 1992, against TransCanada and Enbridge Inc. for damages of \$500 million alleged to arise from the creation of a control zone within 30 metres of the pipeline pursuant to Section 112 of the NEB Act. The Company believes the claim is without merit and will vigorously defend the action. The Company has made no provision for any potential liability. A liability, if any, would be dealt with through the regulatory process.

The Company and its subsidiaries are subject to various other legal proceedings and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of Management that the resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

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

TransCanada has guaranteed the equity undertaking of a subsidiary which supports the payment, under certain conditions, of principal and interest on US\$161 million of public debt obligations of TransGas de Occidente, S.A. (TransGas). The Company has a 46.5 per cent interest in TransGas. Under the terms of the agreement, the Company severally with another major multinational company may be required to fund more than their proportionate share of debt obligations of TransGas in the event that the minority shareholders fail to contribute. Any payments made by TransCanada under this agreement convert into share capital of TransGas. The potential exposure is contingent on the impact of any change of law on TransGas' ability to service the debt. From the issuance of the debt in 1995 to date, there has been no change in applicable law and thus no exposure to TransCanada. The debt matures in 2010. The Company has made no provision related to this guarantee.

In connection with the acquisition of GTN, US\$241 million of the purchase price was deposited into an escrow account. The escrowed funds represent the full face amount of the potential liability under certain GTN guarantees and are to be used to satisfy the liability under these designated guarantees.

#### **NOTE 21 Discontinued Operations**

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

**NOTE 22 U.S. GAAP (Restated <sup>(13)</sup>)**

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

**Condensed Statement of Consolidated Income and Comprehensive Income in Accordance with U.S. GAAP <sup>(1)</sup>**

Year ended December 31 (millions of dollars except per share amounts)	Restated 2004	Restated 2003	Restated 2002
Revenues	4,700	4,919	4,565
Cost of sales	440	592	441
Other costs and expenses	1,638	1,663	1,532
Depreciation	857	819	729
	2,935	3,074	2,702
Operating income	1,765	1,845	1,863
Other (income)/expenses			
Equity income <sup>(1)</sup>	(353)	(334)	(260)
Other expenses <sup>(2)(12)(13)</sup>	826	873	882
Dilution gain <sup>(12)</sup>	(40)	–	–
Income taxes	490	515	499
	923	1,054	1,121
Income from continuing operations – U.S. GAAP	842	791	742
Net income from discontinued operations – U.S. GAAP	52	50	–
Income before cumulative effect of the application of accounting changes in accordance with U.S. GAAP	894	841	742
Cumulative effect of the application of accounting changes, net of tax <sup>(3)</sup>	–	(13)	–
<b>Net Income in Accordance with U.S. GAAP</b>	<b>894</b>	<b>828</b>	<b>742</b>
Adjustments affecting comprehensive income under U.S. GAAP			
Foreign currency translation adjustment, net of tax	(31)	(54)	1
Changes in minimum pension liability, net of tax <sup>(4)</sup>	72	(2)	(40)
Unrealized gain/(loss) on derivatives, net of tax <sup>(5)</sup>	1	8	(4)
<b>Comprehensive Income in Accordance with U.S. GAAP</b>	<b>936</b>	<b>780</b>	<b>699</b>
<b>Net Income Per Share in Accordance with U.S. GAAP</b>			
Continuing operations	\$ 1.74	\$ 1.65	\$ 1.55
Discontinued operations	0.11	0.10	–
Income before cumulative effect of the application of accounting changes in accordance with U.S. GAAP	\$ 1.85	\$ 1.75	\$ 1.55
Cumulative effect of the application of accounting changes, net of tax <sup>(3)</sup>	–	(0.03)	–
Basic	\$ 1.85	\$ 1.72	\$ 1.55
Diluted <sup>(6)</sup>	\$ 1.84	\$ 1.71	\$ 1.54
<b>Net Income Per Share in Accordance with Canadian GAAP</b>			
Basic	\$ 2.13	\$ 1.76	\$ 1.56
Diluted	\$ 2.12	\$ 1.76	\$ 1.55
Dividends per common share	\$ 1.16	\$ 1.08	\$ 1.00

**Reconciliation of Income from Continuing Operations**

Year ended December 31 (millions of dollars)	Restated 2004	Restated 2003	Restated 2002
<b>Net Income from Continuing Operations in Accordance with Canadian GAAP</b>	<b>980</b>	801	747
U.S. GAAP adjustments			
Unrealized (loss)/gain on foreign exchange and interest rate derivatives <sup>(5)</sup>	(12)	(9)	30
Tax impact of (loss)/gain on foreign exchange and interest rate derivatives	4	3	(12)
Unrealized gain/(loss) on energy marketing contracts <sup>(3)</sup>	10	28	(21)
Tax impact of unrealized gain/(loss) on energy marketing contracts	(3)	(10)	8
Equity loss <sup>(7)</sup>	(2)	(18)	–
Tax impact of equity loss	–	6	–
Amortization of deferred gains related to Power LP <sup>(12)(13)</sup>	(3)	(10)	(10)
Deferred gains related to Power LP <sup>(12)(13)</sup>	(132)	–	–
<b>Income from Continuing Operations in Accordance with U.S. GAAP</b>	<b>842</b>	791	742

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

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

**Condensed Balance Sheet in Accordance with U.S. GAAP <sup>(1)</sup>**

December 31 (millions of dollars)	2004	Restated 2003
Current assets	908	1,020
Long-term investments <sup>(7)(8)</sup>	1,887	1,760
Plant, property and equipment	17,083	15,753
Regulatory asset <sup>(9)</sup>	2,606	2,721
Other assets	1,235	1,385
	23,719	22,639
Current liabilities <sup>(10)</sup>	2,573	2,135
Deferred amounts <sup>(3)(5)(8)(12)(13)</sup>	803	692
Long-term debt <sup>(5)</sup>	9,753	9,494
Deferred income taxes <sup>(9)</sup>	3,048	3,039
Preferred securities <sup>(11)</sup>	554	694
Non-controlling interests	465	471
Shareholders' equity <sup>(12)(13)</sup>	6,523	6,114
	23,719	22,639

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

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

- (1) In accordance with U.S. GAAP, the Condensed Statement of Consolidated Income and Balance Sheet are prepared using the equity method of accounting for joint ventures. Excluding the impact of other U.S. GAAP adjustments, the use of the proportionate consolidation method of accounting for joint ventures, as required under Canadian GAAP, results in the same net income and shareholders' equity.
- (2) Other expenses included an allowance for funds used during construction of \$3 million for the year ended December 31, 2004 (2003 – \$2 million; 2002 – \$4 million).
- (3) Subsequent to October 1, 2003, the energy contracts that were accounted for as hedges under the provisions of Statement of Financial Accounting Standards (SFAS) No. 133 qualified as hedges. Substantially all derivative energy contracts are now accounted for as hedges under both U.S. and Canadian GAAP. All gains or losses on the contracts that did not qualify as hedges under SFAS No. 133, and the amounts of any ineffectiveness on the hedging contracts, are included in income each period. Substantially all of the amounts recorded in 2004 and 2003 as differences between U.S. and Canadian GAAP relate to gains and losses on contracts for periods before they were documented as hedges for purposes of U.S. GAAP and to differences in accounting with respect to physical energy trading contracts in the U.S. and Canada.
- (4) Under U.S. GAAP, a net loss recognized pursuant to SFAS No. 87 "Employers' Accounting for Pensions" as an additional pension liability not yet recognized as net period pension cost, must be recorded as a component of comprehensive income. The net amount recognized at December 31 is as follows.

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

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

- (5) Effective January 1, 2004, all foreign exchange and interest rate derivatives are recorded in the Company's consolidated financial statements at fair value under Canadian GAAP. Under the provisions of SFAS No. 133 "Accounting for Derivatives and Hedging Activities", all derivatives are recognized as assets and liabilities on the balance sheet and measured at fair value. For derivatives designated as fair value hedges, changes in the fair value are recognized in earnings together with an equal or lesser amount of changes in the fair value of the hedged item attributable to the hedged risk. For derivatives designated as cash flow hedges, changes in the fair value of the derivative that are effective in offsetting the hedged risk are recognized in other comprehensive income until the hedged item is recognized in earnings. Any ineffective portion of the change in fair value is recognized in earnings each period. Substantially all of the amounts recorded in 2004 as differences between U.S. and Canadian GAAP, for income from continuing operations, relate to the differences in accounting treatment with respect to the hedged item and, for comprehensive income, relate to cash flow hedges.
- During 2004, under the provisions of SFAS 133, net gains of \$10 million (2003 – \$47 million; 2002 – \$38 million) from the hedges of changes in the fair value of long-term debt, and net losses of \$18 million (2003 – \$53 million; 2002 – \$20 million) in the fair value of the hedged item were included in earnings for U.S. GAAP purposes as an adjustment to interest expense and foreign exchange losses. No amounts of the derivatives' gains or losses were excluded from the assessment of hedge effectiveness in fair value hedging relationships.
- No amounts were included in income in 2004, 2003 and 2002 with respect to ineffectiveness of cash flow hedges. For amounts included in other comprehensive income at December 31, 2004, \$2 million (2003 – \$9 million; 2002 – \$(5) million) relates to the hedging of interest rate risk, \$(3) million (2003 – \$5 million; 2002 – \$1 million) relates to the hedging of foreign exchange rate risk, and \$2 million (2003 – \$(6) million; 2002 – nil) relates to the hedging of energy price risk. Of these amounts, \$2 million is expected to be recorded in earnings during 2005. At December 31, 2004, assets of \$(29) million (2003 – \$91 million) and liabilities of \$(27) million (2003 – \$93 million) were (reduced)/added for U.S. GAAP purposes to reflect the fair value of derivatives and the corresponding change in the fair value of hedged items.
- (6) Diluted net income per share in accordance with U.S. GAAP for the year ended December 31, 2004 consists of continuing operations – \$1.73 per share (2003 – \$1.61 per share; 2002 – \$1.54 per share), and discontinued operations – \$0.11 per share (2003 – \$0.10 per share; 2002 – nil).

- (7) Under Canadian GAAP, pre-operating costs incurred during the commissioning phase of a new project are deferred until commercial production levels are achieved. After such time, those costs are amortized over the estimated life of the project. Under U.S. GAAP, such costs are expensed as incurred. Certain start-up costs incurred by Bruce Power, L.P. (an equity investment) are required to be expensed under U.S. GAAP. Under both Canadian GAAP and U.S. GAAP, interest is capitalized on expenditures relating to construction of development projects actively being prepared for their intended use. In Bruce Power, L.P. under U.S. GAAP, the carrying value of development projects against which interest is capitalized is lower due to the expensing of pre-operating costs.
- (8) Effective January 1, 2003, the Company adopted the provisions of Financial Interpretation (FIN) 45 that require the recognition of a liability for the fair value of certain guarantees that require payments contingent on specified types of future events. The measurement standards of FIN 45 are applicable to guarantees entered into after January 1, 2003. For U.S. GAAP purposes, the fair value of guarantees recorded as a liability at December 31, 2004 was \$9 million (2003 – \$4 million) and relates to the Company's equity interest in Bruce Power.
- (9) Under U.S. GAAP, the Company is required to record a deferred income tax liability for its cost-of-service regulated businesses. As these deferred income taxes are recoverable through future revenues, a corresponding regulatory asset is recorded for U.S. GAAP purposes.
- (10) Current liabilities at December 31, 2004 include dividends payable of \$146 million (2003 – \$136 million) and current taxes payable of \$260 million (2003 – \$271 million).
- (11) The fair value of the preferred securities at December 31, 2004 was \$572 million (2003 – \$612 million). The Company made preferred securities charges payments of \$48 million for the year ended December 31, 2004 (2003 – \$57 million; 2002 – \$58 million).
- (12) The Company records its investment in Power LP using the proportionate consolidation method for Canadian GAAP purposes and as an equity investment for U.S. GAAP purposes. During the period from 1997 to April 2004, the Company was obligated to fund the redemption of Power LP units in 2017. As a result, under Canadian GAAP, TransCanada accounted for the issuance of units by Power LP to third parties as a sale of a future net revenue stream and the resulting gains were deferred and amortized to income over the period to 2017. The redemption obligation was removed in April 2004 and the unamortized gains were recognized as income. Under U.S. GAAP, any such gains in the period from 1997 to April 2004 are characterized as dilution gains and, because the Company was committed to fund the redemption of the units, the gains are recorded, on an after-tax basis, as equity transactions in shareholders' equity. The Company's accounting policy for dilution gains is to record them as income for both Canadian and U.S. GAAP purposes, however, U.S. GAAP requires such gains to be recorded directly in equity if there is a contemplation of reacquisition of units. With the removal of the redemption obligation in April 2004, subsequent issuances of units by Power LP are accounted for as dilution gains in income for both Canadian and U.S. GAAP purposes (see Note 8).
- (13) Correction of Error:  
In the period 1997 to 2001, the Company recorded certain transactions involving Power LP as sales of a revenue stream for both Canadian and U.S. GAAP purposes. For U.S. GAAP purposes, these transactions should have been accounted for as dilution gains (see footnote 12 above). This has been corrected on a retroactive basis. The impact on previously reported amounts for U.S. GAAP purposes is as follows:

(millions of dollars except per share amounts)	2004	2003	2002
<b>Decrease in:</b>			
Income from continuing operations	135	10	10
Net income	135	10	10
Net income per share in accordance with U.S. GAAP			
Continuing operations	\$ 0.28	\$ 0.02	\$ 0.02
Discontinued operations	-	-	-
Basic	\$ 0.28	\$ 0.02	\$ 0.02
Diluted	\$ 0.28	\$ 0.02	\$ 0.02

For U.S. GAAP purposes, the correction had no impact on the accumulated shareholders' equity at December 31, 2004 and the impact at December 31, 2003 was an increase of \$135 million.

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

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

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

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

### Summarized Financial Information of Long-Term Investments

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

Year ended December 31 (millions of dollars)	2004	2003	2002
<b>Income</b>			
Revenues	1,149	1,063	798
Other costs and expenses	(575)	(528)	(273)
Depreciation	(155)	(141)	(146)
Financial charges and other	(66)	(60)	(119)
Proportionate share of income before income taxes of long-term investments	353	334	260
<b>Balance Sheet</b>			
December 31 (millions of dollars)	2004	2003	
Current assets	361	385	
Plant, property and equipment	3,020	2,944	
Current liabilities	(248)	(204)	
Deferred amounts (net)	(199)	(286)	
Non-recourse debt	(1,030)	(1,060)	
Deferred income taxes	(17)	(19)	
Proportionate share of net assets of long-term investments	1,887	1,760	