2002 CONSOLIDATED FINANCIAL STATEMENTS
REPORT OF MANAGEMENT

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

Management has prepared Management's Discussion and Analysis (MD&A) which is based on the Company's financial results prepared in accordance with Canadian GAAP. It compares the Company's financial performance in 2002 to 2001 and should be read in conjunction with the consolidated financial statements and accompanying notes. In addition, significant changes between 2001 and 2000 are highlighted. Note 20 to the consolidated financial statements describes the impact on the consolidated financial statements of significant differences between Canadian and United States GAAP.

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

The Board of Directors has appointed an Audit and Risk Management Committee consisting of unrelated, non-management directors which meets at least four times during the year with Management and independently with each of the internal and external auditors and as a group to review any significant accounting, internal control and auditing matters. The Audit and Risk Management Committee reviews the consolidated financial statements with Management and the external auditors before the consolidated financial statements are submitted to the Board of Directors for approval. The internal and external auditors have free access to the Audit and Risk Management Committee without obtaining prior Management approval.

With respect to the external auditors, KPMG LLP, the Audit and Risk Management Committee approves the terms of engagement and reviews the annual audit plan, the Auditors' Report and results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The independent external auditors, KPMG LLP, have been appointed by the shareholders to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's financial position, results of operations and cash flows in accordance with Canadian generally accepted accounting principles. The report of KPMG LLP on page 48 outlines the scope of their examination and their opinion on the consolidated financial statements.

Harold N. Kvisle
President and
Chief Executive Officer

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

February 25, 2003

CONSOLIDATED INCOME

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

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

CONSOLIDATED CASH FLOWS

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

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

CONSOLIDATED BALANCE SHEET

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

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

On behalf of the Board:

Harold N. Kvisle
Director

Harry G. Schaefer
Director

CONSOLIDATED RETAINED EARNINGS

Year ended December 31	**2002**	2001	2000
(millions of dollars)			
Balance at beginning of year	**586**	395	85
Net income	**805**	686	768
Preferred securities charges	**(36)**	(45)	(44)
Preferred share dividends	**(22)**	(22)	(35)
Common share dividends	**(479)**	(428)	(379)
	854	586	395

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

AUDITORS' REPORT

To the Shareholders of TransCanada PipeLines Limited

We have audited the consolidated balance sheets of TransCanada PipeLines Limited as at December 31, 2002 and 2001 and the consolidated statements of income, retained earnings and cash flows for each of the years in the three-year period ended December 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and 2001 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2002 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada

February 25, 2003

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

TRANSMISSION

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

POWER

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

NOTE 1 Accounting Policies

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

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

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

Regulation The Alberta System is regulated by the Alberta Energy and Utilities Board (EUB), and the Canadian Mainline and the BC System are subject to the authority of the National Energy Board (NEB). All Canadian natural gas transmission operations are regulated with respect to the determination of tolls, construction and operations. In June 2002, the Company received the NEB decision on its Fair Return application (Fair Return decision) to determine the cost of capital to be included in the calculation of 2001 and 2002 final tolls on the Canadian Mainline. The Fair Return decision on the cost of capital included an increase in the deemed common equity ratio from 30 to 33 per cent effective January 1, 2001. The NEB also decided that the return on equity as calculated based on the NEB formula continued to be appropriate for the Canadian Mainline which results in an approved rate of return on common equity of 9.61 per cent for 2001 and 9.53 per cent for 2002. The natural gas pipelines in the United States and certain power plants are also subject to the authority of regulatory bodies. In order to achieve a proper matching of revenues and expenses, the timing of recognition of certain revenues and expenses in these businesses may differ from that otherwise expected under generally accepted accounting principles.

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

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

Plant, Property and Equipment

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

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

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

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

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

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

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

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

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

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

NOTE 2 Accounting Changes

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

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

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

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

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

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

NOTE 3 Segmented Information

Net Income/(Loss) [1]

Year ended December 31, 2002	Transmission	Power	Corporate	Total
(millions of dollars)				
Revenues	**3,921**	**1,293**	**–**	**5,214**
Cost of sales [2]	**–**	**(627)**	**–**	**(627)**
Other costs and expenses	**(1,166)**	**(371)**	**(9)**	**(1,546)**
Depreciation	**(783)**	**(65)**	**–**	**(848)**
Operating income/(loss)	**1,972**	**230**	**(9)**	**2,193**
Financial and preferred equity charges	**(821)**	**(13)**	**(91)**	**(925)**
Financial charges of joint ventures	**(90)**	**–**	**–**	**(90)**
Interest and other income	**50**	**13**	**23**	**86**
Income taxes	**(458)**	**(84)**	**25**	**(517)**
Continuing Operations	**653**	**146**	**(52)**	**747**
Discontinued Operations				**–**
Net Income Applicable to Common Shares				**747**

Year ended December 31, 2001	Transmission	Power	Corporate	Total
(millions of dollars)				
Revenues	3,880	1,395	–	5,275
Cost of sales [2]	–	(712)	–	(712)
Other costs and expenses	(1,226)	(361)	(31)	(1,618)
Depreciation	(753)	(37)	(3)	(793)
Operating income/(loss)	1,901	285	(34)	2,152
Financial and preferred equity charges	(856)	(15)	(85)	(956)
Financial charges of joint ventures	(98)	(9)	–	(107)
Interest and other income	30	13	34	77
Income taxes	(392)	(106)	18	(480)
Continuing Operations	585	168	(67)	686
Discontinued Operations				(67)
Net Income Applicable to Common Shares				619

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

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

(2) Cost of sales include commodity purchases for resale.

Total Assets

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

Geographic Information

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

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

Plant, Property and Equipment

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

Capital Expenditures

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

NOTE 4 Plant, Property and Equipment

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

NOTE 5 Other Assets

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

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

NOTE 6 Joint Venture Investments

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

(1) In May 2001, the Company increased its interest in Iroquois from 35.0 per cent to 41.0 per cent.
(2) During 2000, the Company increased its interest in TransCanada Power, L.P. from 32.7 per cent to 41.6 per cent and in October 2001, decreased its interest to 35.6 per cent.
(3) In December 2001, the Company purchased 50.0 per cent of ASTC Power Partnership, which is located in Alberta and holds a power purchase arrangement. In 2002, the underlying power volume related to the 50.0 per cent ownership interest in the Partnership was effectively transferred to TransCanada.
(4) In October 2000, the Company increased its interest in the Ocean State Power plant from 70.1 per cent to 100 per cent and the investment was consolidated subsequent to that date.

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

Summarized Financial Information of Joint Ventures

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

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

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

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

NOTE 7 Long-Term Investments

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

The Northern Border equity investment (Northern Border) is the result of the Company holding a 33.4 per cent interest in TC PipeLines, LP, which holds a 30.0 per cent interest in Northern Border Pipeline Company. The Company holds a 33.3 per cent interest in Portland Natural Gas Transmission System Partnership (Portland) and a 46.5 per cent interest in TransGas de Occidente S.A. (TransGas). Consolidated retained earnings at December 31, 2002 include undistributed earnings from these equity investments of $44 million (2001 – $40 million).

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

NOTE 8 Long-Term Debt

	Maturity Dates	2002 Outstanding December 31 [1]	2002 Weighted Average Interest Rate [2]	2001 Outstanding December 31 [1]	2001 Weighted Average Interest Rate [2]
Alberta System					
Debentures and Notes					
Canadian dollars	2003 to 2024	**798**	**11.0%**	819	11.0%
U.S. dollars (2002 – US$500; 2001 – US$625)	2004 to 2023	**790**	**8.3%**	995	8.2%
Medium-Term Notes					
Canadian dollars	2005 to 2030	**767**	**7.4%**	774	7.4%
U.S. dollars (2002 and 2001 – US$233)	2026 to 2029	**368**	**7.7%**	371	7.7%
Unsecured Loans					
U.S. dollars (2002 and 2001 – US$107)	2003	**169**	**2.1%**	170	2.3%
		2,892		3,129	
Foreign exchange differential recoverable through the tollmaking process		**(271)**		(322)	
		2,621		2,807	
Canadian Mainline					
First Mortgage Pipe Line Bonds					
Pounds Sterling (2002 and 2001 – £25)	2007	**64**	**16.5%**	58	16.5%
Debentures					
Canadian dollars	2008 to 2020	**1,354**	**10.9%**	1,455	10.9%
U.S. dollars (2002 and 2001 – US$800)	2012 to 2023	**1,264**	**9.2%**	1,274	9.2%
Medium-Term Notes					
Canadian dollars	2003 to 2031	**2,405**	**7.0%**	2,585	7.1%
U.S. dollars (2002 and 2001 – US$120)	2010	**190**	**6.1%**	191	6.1%
		5,277		5,563	
Foreign exchange differential recoverable through the tollmaking process		**(330)**		(337)	
		4,947		5,226	
Other					
Medium-Term Notes					
Canadian dollars	2005 to 2030	**342**	**6.6%**	342	6.6%
U.S. dollars (2002 and 2001 – US$665)	2006 to 2029	**1,050**	**6.8%**	1,059	6.8%
Subordinated Debentures					
U.S. dollars (2002 and 2001 – US$57)	2006	**90**	**9.1%**	91	9.1%
Unsecured Loans and Debentures					
Canadian dollars	2003	**110**	**8.4%**	110	8.4%
U.S. dollars (2002 – US$109; 2001 – US$123)	2006 to 2011	**172**	**8.3%**	195	8.3%
		1,764		1,797	
		9,332		9,830	
Less: Current Portion of Long-Term Debt		**517**		483	
		8,815		9,347	

(1) Amounts outstanding are stated in millions of Canadian dollars; amounts denominated in currencies other than Canadian dollars are stated in millions.

(2) Weighted average interest rates are stated as at the respective outstanding dates. The effective weighted average interest rates resulting from swap agreements are as follows: Alberta System U.S. dollar unsecured loans – 8.3 per cent (2001 – 8.3 per cent); and Other U.S. dollar subordinated debentures – 9.0 per cent (2001 – 8.9 per cent).

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

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

Alberta System

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

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

Canadian Mainline

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

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

Other

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

Financial Charges

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

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

NOTE 9 Non-Recourse Debt of Joint Ventures

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

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

(2) Weighted average interest rates are stated as at the respective outstanding dates. At December 31, 2002, the effective weighted average interest rates on the bank loan of Iroquois and senior unsecured notes of Foothills resulting from swap agreements are 4.8 per cent (2001 – 6.3 per cent) and 5.8 per cent (2001 – 5.9 per cent), respectively.

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

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

Financial Charges of Joint Ventures

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

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

NOTE 10 Junior Subordinated Debentures and Preferred Securities

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

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

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

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

Since the deferred interest may be settled through the issuance of common shares at the option of the Company, the Preferred Securities are classified into their respective debt and equity components. The equity component of the Preferred Securities is $674 million at December 31, 2002 (2001 – $675 million).

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

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

NOTE 11 Preferred Shares

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

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

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

NOTE 12 Common Shares

	Number of Shares	Amount
	(thousands)	*(millions of dollars)*
Outstanding at January 1, 2000	474,531	4,535
Exercise of options	382	5
Outstanding at December 31, 2000	474,913	4,540
Exercise of options	1,718	24
Outstanding at December 31, 2001	476,631	4,564
Exercise of options	**2,871**	**50**
Outstanding at December 31, 2002	**479,502**	**4,614**

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

Net Income Per Share Basic and diluted earnings per share are calculated based on the weighted average number of common shares outstanding during the year of 478.3 million and 480.7 million (2001 – 475.8 million and 477.6 million; 2000 – 474.6 million and 475.2 million), respectively.

Stock Options	Number of Shares	Weighted Average Exercise Prices	Options Exercisable
	(thousands)		*(thousands)*
Outstanding at January 1, 2000	12,871	$ 20.27	9,661
Granted	3,475	$ 10.30	
Exercised	(382)	$ 12.86	
Cancelled or expired	(573)	$ 18.85	
Outstanding at December 31, 2000	15,391	$ 18.25	12,102
Granted	2,142	$ 18.07	
Exercised	(1,718)	$ 14.08	
Cancelled or expired	(1,365)	$ 21.45	
Outstanding at December 31, 2001	14,450	$ 18.42	11,376
Granted	**1,946**	**$ 21.43**	
Exercised	**(2,871)**	**$ 17.18**	
Cancelled or expired	**(633)**	**$ 23.16**	
Outstanding at December 31, 2002	**12,892**	**$ 18.92**	**10,258**

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

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
	(thousands)	*(years)*		*(thousands)*	
$10.03 to $13.91	2,243	7.1	$10.62	1,889	$10.72
$14.21 to $18.89	3,098	7.1	$17.52	2,286	$17.35
$19.00 to $20.59	2,830	5.7	$20.07	2,780	$20.09
$21.00 to $21.86	2,173	8.9	$21.43	755	$21.42
$22.85 to $24.61	2,548	5.1	$24.49	2,548	$24.49
	12,892	6.8	$18.92	10,258	$18.95

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

Restricted Share Unit (RSU) Plan Effective January 1, 2002, the Company implemented the RSU plan. This is a long-term, broad-based employee incentive plan, which granted units to each eligible employee. The units will vest at the end of three years, should certain conditions be achieved which include the employee's continued employment during that period and achievement of specified corporate performance targets. The Company is recording compensation expense over the three year vesting period and the value of the units will be paid at the end of the vesting period.

Shareholder Rights Plan The Company's Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Under certain circumstances, each common share is entitled to one right which entitles certain holders to purchase common shares of the Company at 50 per cent of the then market price. The Plan was reaffirmed by shareholders in 2001 with certain amendments.

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

NOTE 13 Risk Management and Financial Instruments

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

Carrying Values of Derivatives The carrying amounts of derivatives, which hedge the price risk of foreign currency denominated assets and liabilities and represent the net unrealized gains or losses on the derivatives, partially offset the foreign exchange adjustment in Shareholders' Equity. Carrying amounts for interest rate swaps represent the net accrued interest from the last payment date to the reporting date. Foreign currency transactions hedged by foreign exchange contracts are recorded at the contract rate. The carrying amounts shown in the tables that follow are recorded in the Consolidated Balance Sheet.

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

The fair values of foreign exchange and interest rate derivatives have been estimated using year-end market rates. These fair values approximate the amount that the Company would receive or pay if the instruments were closed out at these dates.

Credit Risk Credit risk results from the possibility that a counterparty to a derivative in which the Company has an unrealized gain fails to perform according to the terms of the contract. Credit exposure is minimized through the use of established credit management techniques, including formal assessment processes, contractual and collateral requirements and credit exposure limits. At December 31, 2002, for foreign currency and interest rate derivatives, total credit risk and the largest credit exposure to a single counterparty were $168 million and $60 million, respectively. At December 31, 2002, for power energy trading contracts, total credit risk and the largest credit exposure to a single counterparty were $4 million and $1 million, respectively.

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

Foreign Investments At December 31, 2002 and 2001, the Company had foreign currency denominated assets and liabilities which created an exposure to changes in exchange rates. The Company uses foreign currency derivatives to hedge this exposure on an after-tax basis. The cross-currency swaps have a floating interest rate which the Company partially hedges by entering into interest rate swaps and forward rate agreements. The Company's portfolio of foreign investment derivatives is comprised of contracts for periods up to 5 years. The fair values shown in the table below for foreign exchange risk are offset by translation gains or losses on the net assets and are recorded in the foreign exchange adjustment in Shareholders' Equity.

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

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

Reconciliation of Foreign Exchange Adjustment

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

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

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

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

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

Foreign Exchange and Interest Rate Management Activity The Company manages the foreign exchange risk of U.S. dollar debt, U.S. dollar expenses and the interest rate exposures of the Alberta System and the Canadian Mainline through the use of foreign currency and interest rate derivatives. These derivatives are comprised of contracts for periods up to 10 years. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms.

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

At December 31, 2002, the principal amounts of cross-currency swaps were US$162 million (2001 – US$407 million). Notional principal amounts for interest rate swaps were $1,024 million (2001 – $780 million) and US$175 million (2001 – US$125 million).

The Company manages the foreign exchange risk and interest rate exposure of its other U.S. dollar debt through the use of foreign currency and interest rate derivatives. The carrying amount and fair value of U.S. dollar interest rate swaps at December 31, 2002 were $2 million (2001 – $2 million) and $55 million (2001 – $30 million), respectively. Notional principal amounts were US$250 million (2001 – US$200 million). These derivatives are comprised of contracts for periods up to 8 years.

Other Fair Values

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

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

NOTE 14 Income Taxes

Provision for Income Taxes

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

Geographic Components of Income

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

Reconciliation of Income Tax Expense

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

Future Income Tax Assets and Liabilities

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

The Company follows the taxes payable method of accounting for income taxes related to the operations of the Canadian natural gas transmission operations. If the liability method of accounting had been used, additional future income tax liabilities in the amount of $1,702 million at December 31, 2002 (2001 – $1,716 million) would have been recorded and would be recoverable from future revenues.

Unremitted Earnings of Foreign Investments Income taxes have not been provided on the unremitted earnings of foreign investments which the Company intends to indefinitely reinvest in foreign operations. If provision for these taxes had been made, future income tax liabilities would increase by approximately $60 million at December 31, 2002 (2001 – $54 million).

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

NOTE 15 Notes Payable

	2002		2001	
	Outstanding December 31	**Weighted Average Interest Rate Per Annum at December 31**	Outstanding December 31	Weighted Average Interest Rate Per Annum at December 31
	(millions of dollars)		*(millions of dollars)*	
Commercial Paper				
Canadian dollars	**258**	**2.9%**	340	2.3%
U.S. dollars	**39**	**1.4%**	–	–
Notes Payable of Joint Ventures				
Canadian dollars	**–**	**–**	3	4.7%
	297		343	

Total credit facilities of $2 billion at December 31, 2002, were available to support the Company's commercial paper program and for general corporate purposes. Of this total, $1.5 billion represents a new committed syndicated credit facility established in December 2002 which replaced existing lines set to expire in mid-2003. The new facility is comprised of a $1.0 billion tranche with a three year term and a $500 million tranche with a 364 day term with a two year term out option. Both tranches are extendible on an annual basis and revolving unless during a term out period.

At December 31, 2002, the Company had used approximately $269 million of its total lines of credit for letters of credit to support its ongoing commercial arrangements. If used, interest on the lines of credit would be charged at prime rates of Canadian chartered and U.S. banks and at other negotiated financial bases. The cost to maintain the unused portion of the lines of credit is approximately $1 million for the year ended December 31, 2002 (2001 – $1 million).

NOTE 16 Employee Future Benefits

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

The Company also provides its employees with other post-employment benefits other than pensions, including special termination benefits and defined life insurance and medical benefits beyond those provided by government-sponsored plans. Effective January 1, 2003, the Company combined its previously existing post-employment benefit plans into one plan for active employees and provided existing retirees the option of adopting the provisions of the new plan. This plan amendment resulted in unamortized past service costs of $7 million.

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

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

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

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

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

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

For measurement purposes, an 8.0 per cent annual rate of increase in the per capita cost of covered health care benefits was assumed for 2003. The rate was assumed to decrease gradually to 5.0 per cent for 2009 and remain at that level thereafter. A one percentage point increase or decrease in assumed health care cost trend rates would have the following effects.

	Increase	Decrease
(millions of dollars)		
Effect on total of service and interest cost components	1	(1)
Effect on post-employment benefit obligation	11	(10)

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

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31	**2002**	2001	2000	**2002**	2001	2000
(millions of dollars)						
Current service cost	**11**	12	15	**2**	2	2
Interest cost	**43**	41	44	**4**	4	3
Expected return on plan assets	**(45)**	(41)	(45)	**–**	–	–
Amortization of transitional obligation related to regulated business	**–**	–	–	**2**	2	2
Amortization of net actuarial loss	**2**	–	–	**–**	–	–
Corporate restructuring giving rise to curtailments	**–**	–	(5)	**–**	–	–
	11	12	9	**8**	8	7
Net benefit plan expense – discontinued operations	**–**	(2)	(2)	**–**	–	–
Net benefit plan expense – continuing operations	**11**	10	7	**8**	8	7

NOTE 17 Changes in Operating Working Capital

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

NOTE 18 Commitments, Contingencies and Guarantees

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

Year ended December 31	Minimum Lease Payments	Amounts Recoverable under Sub-Leases	Net Payments
(millions of dollars)			
2003	27	(9)	18
2004	25	(7)	18
2005	25	(7)	18
2006	24	(7)	17
2007	22	(6)	16

At December 31, 2002, TransCanada held a 35.6 per cent interest in TransCanada Power, L.P. which is a publicly-held limited partnership. On June 30, 2017, the partnership will redeem all units outstanding, not held directly or indirectly by TransCanada, at their then fair market value, being the average of the fair market values assigned thereto by independent valuators, plus all declared and unpaid distributions of distributable cash thereon (the Redemption Price). The Redemption Price will be satisfied by TransCanada in cash or, at the election of TransCanada, in common shares of TransCanada or a combination of cash and common shares.

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

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

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

Guarantees TransCanada has guaranteed the equity undertaking of a subsidiary which supports the payment of debt obligations of TransGas de Occidente, S.A. (TransGas), in the event a change of law would result in insufficient funds in TransGas to pay the interest and principal on US$206 million of its public debt obligations. The Company has a 46.5 per cent interest in TransGas. Under the terms of the agreement, the Company severally with another major multinational company may be required to fund more than their proportionate share of debt obligations of TransGas in the event that the minority shareholders fail to contribute. Any payments made by TransCanada under this agreement convert into share capital of TransGas. The potential exposure is contingent on the impact of any change of law on TransGas' ability to service the debt. From the issuance of the debt in 1995 to date, there has been no change in applicable law and thus no exposure to TransCanada. The debt matures in 2010. The Company has made no provision related to this guarantee.

NOTE 19 Discontinued Operations

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

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

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

Net Income/(Loss)

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

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

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

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

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

Net Income Reconciliation

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

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

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

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

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

During 2002, net gains of $38 million (2001 – $36 million) from the hedges of changes in the fair value of long-term debt, and net losses of $20 million (2001 – $44 million) in the fair value of the hedged item were included in earnings as an adjustment to interest expense and foreign exchange losses. The difference of the change in the fair value of the derivative as compared to the change in the fair value of the hedged item of $18 million (2001 – $(8) million), after tax, is included in earnings for U.S. GAAP purposes. During 2002 and 2001, no amounts of the derivatives' gains or losses were excluded from the assessment of hedge effectiveness in fair value hedging relationships.

No amounts were included in income in 2002 and 2001 with respect to cash flow hedges. For amounts included in other comprehensive income at December 31, 2002, $(5) million (2001 – $(3) million) relates to the hedge of interest rate risk and $1 million (2001 – $(2) million) relates to the hedge of foreign exchange rate risk. Of these amounts, none are expected to be recorded in earnings during 2003.

At December 31, 2002, additional assets of $198 million (2001 – $162 million) and additional liabilities of $196 million (2001 – $187 million) were recorded for U.S. GAAP purposes to reflect the fair value of derivatives designated as hedges and the corresponding change in the fair value of items designated as hedges.

(3) Under U.S. GAAP, energy trading contracts are measured at fair value determined as at the balance sheet date. In 2002, TransCanada adopted the transitional provisions of FASB Emerging Issues Task Force (EITF) 02-3, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities", whereby the Company is netting all mark-to-market revenues and expenses related to energy trading contracts. This accounting change has been applied retroactively with reclassification of prior periods. In 2003, the Company will fully adopt EITF 02-3. The Company's energy trading contracts that are derivatives held for trading purposes will be measured at fair value and accounted for under the provisions of SFAS No. 133. The Company's energy trading contracts that are not derivatives will not be subject to mark-to-market accounting.

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

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

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

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

Comprehensive Income in Accordance with U.S. GAAP

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

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

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

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

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

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

(7) Under U.S. GAAP, a net loss recognized pursuant to SFAS No. 87 "Employers' Accounting for Pensions" as an additional pension liability not yet recognized as net period pension cost, must be recorded as a component of comprehensive income.

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

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

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

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

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

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

Stock-Based Compensation Under the transition rules provided by SFAS No. 148 "Accounting for Stock-Based Compensation – Transition and Disclosure – an amendment of FASB Statement No. 123", the Company has expensed stock options granted in 2002. The use of the fair value method of SFAS No. 123 "Accounting for Stock-Based Compensation" for previously issued options would have resulted in net income under U.S. GAAP of $770 million in 2002 (2001 – $643 million; 2000 – $712 million) and net income per share (basic) of $1.56 in 2002 (2001 – $1.30 per share; 2000 – $1.43 per share).

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

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

In November 2002, the FASB issued Financial Interpretation (FIN) 45 that will require the recognition of a liability for the fair value of certain guarantees that require payments contingent on specified types of future events. The measurement standards of FIN 45 are applicable to guarantees entered into after January 1, 2003. For guarantees that existed as at December 31, 2002, FIN 45 requires additional disclosures which have been included in these consolidated financial statements to the extent applicable to the Company.

In January 2003, the FASB issued FIN 46 that will require the consolidation of certain entities that are controlled through financial interests that indicate control (referred to as "variable interests"). Variable interests are the rights or obligations that convey economic gains or losses from changes in the values of an entity's assets or liabilities. The holder of the majority of an entity's variable interests will be required to consolidate the variable interest entity. The Company does not have any variable interest entities as interpreted under FIN 46 that would result in the consolidation of any additional entities that existed at December 31, 2002.

Summarized Financial Information of Long-Term Investments

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

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

NOTE 21 Subsequent Event

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

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

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

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

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