TransCanada PipeLines Limited

Restated Consolidated Financial Statements
December 31, 2004

AUDITORS' REPORT

To the Shareholder of TransCanada PipeLines Limited

We have audited the consolidated balance sheets of TransCanada PipeLines Limited 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 audit.

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Our previous report dated February 28, 2005 has been withdrawn and the financial statements have been revised as explained in note 23 to the revised consolidated financial statements.

Chartered Accountants

KPMG LLP

Calgary, Canada

February 28, 2005, except
as to note 23 which is
as of July 28, 2005

TRANSCANADA PIPELINES LIMITED
CONSOLIDATED INCOME

Year ended December 31 (millions of dollars)	**2004**	**2003**	**2002**
Revenues	**5,107**	5,357	5,214
Operating Expenses			
Cost of sales	**539**	692	627
Other costs and expenses	**1,635**	1,682	1,546
Depreciation	**945**	914	848
	3,119	3,288	3,021
Operating Income	**1,988**	2,069	2,193
Other Expenses/(Income)			
Financial charges *(Note 9)*	**812**	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)**	—	—
	439	673	871
Income from Continuing Operations before Income Taxes and Non- Controlling Interests	**1,549**	1,396	1,322
Income Taxes *(Note 16)*			
Current	**431**	305	270
Future	**77**	230	247
	508	535	517
Non-Controlling Interests	**10**	2	—
Net Income from Continuing Operations	**1,031**	859	805
Net Income from Discontinued Operations *(Note 22)*	**52**	50	—
Net Income	**1,083**	909	805
Preferred Securities Charges	**31**	36	36
Preferred Share Dividends	**22**	22	22
Net Income Applicable to Common Shares	**1,030**	851	747
Net Income Applicable to Common Shares			
Continuing operations	**978**	801	747
Discontinued operations	**52**	50	—
	1,030	851	747

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

TRANSCANADA PIPELINES LIMITED
CONSOLIDATED CASH FLOWS

Year ended December 31 (millions of dollars)	2004	2003	2002
Cash Generated from Operations			
Net income from continuing operations	**1,031**	859	805
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)
Pension funding in excess of expense	**(29)**	(65)	(33)
Other	**(32)**	(9)	(34)
Funds generated from continuing operations	**1,672**	1,810	1,827
Decrease in operating working capital *(Note 20)*	**33**	112	33
Net cash provided by continuing operations	**1,705**	1,922	1,860
Net cash (used in)/provided by discontinued operations	**(6)**	(17)	59
	1,699	1,905	1,919
Investing Activities			
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)
Financing Activities			
Dividends and preferred securities charges	**(623)**	(588)	(546)
Advances from parent	**35**	46	—
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	**—**	18	50
Redemption of junior subordinated debentures	**—**	(218)	—
Net cash used in financing activities	**(156)**	(629)	(1,064)
Effect of Foreign Exchange Rate Changes on Cash and Short-Term Investments	**(87)**	(52)	(3)
(Decrease)/Increase in Cash and Short-Term Investments	**(150)**	125	(87)
Cash and Short-Term Investments			
Beginning of year	**337**	212	299
Cash and Short-Term Investments			
End of year	**187**	337	212

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

TRANSCANADA PIPELINES LIMITED
CONSOLIDATED BALANCE SHEET

December 31 (millions of dollars)	**2004**	**2003**
ASSETS		
Current Assets		
Cash and short-term investments	**187**	337
Accounts receivable	**627**	603
Inventories	**174**	165
Other	**120**	88
	1,108	1,193
Long-Term Investments *(Note 7)*	**840**	733
Plant, Property and Equipment *(Notes 4, 9 and 10)*	**18,704**	17,415
Other Assets *(Note 5)*	**1,477**	1,357
	22,129	20,698
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable *(Note 17)*	**546**	367
Accounts payable	**1,215**	1,131
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
	2,824	2,275
Deferred Amounts *(Note 11)*	**666**	561
Long-Term Debt *(Note 9)*	**9,713**	9,465
Future Income Taxes *(Note 16)*	**509**	427
Non-Recourse Debt of Joint Ventures *(Note 10)*	**779**	761
Preferred Securities *(Note 12)*	**19**	22
	14,510	13,511
Non-Controlling Interests	**76**	82
Shareholders' Equity		
Preferred securities *(Note 12)*	**670**	672
Preferred shares *(Note 13)*	**389**	389
Common shares *(Note 14)*	**4,632**	4,632
Contributed surplus	**270**	267
Retained earnings	**1,653**	1,185
Foreign exchange adjustment *(Note 15)*	**(71)**	(40)
	7,543	7,105
Commitments, Contingencies and Guarantees *(Note 21)*		
	22,129	20,698

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

TRANSCANADA PIPELINES LIMITED
CONSOLIDATED RETAINED EARNINGS

Year ended December 31 (millions of dollars)	**2004**	**2003**	**2002**
Balance at beginning of year	**1,185**	854	586
Net income	**1,083**	909	805
Preferred securities charges	**(31)**	(36)	(36)
Preferred share dividends	**(22)**	(22)	(22)
Common share dividends	**(562)**	(520)	(479)
	1,653	1,185	854

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

TransCanada PipeLines Limited (the Company or TCPL) is a leading North American energy company. TCPL 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 23. 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 TCPL were exchanged on a one-to-one basis for common shares of TransCanada Corporation (TransCanada). As a result, TCPL became a wholly-owned subsidiary of TransCanada. The consolidated financial statements include the accounts of TCPL, the consolidated accounts of all subsidiaries and TCPL's proportionate share of the accounts of the Company's joint venture investments.

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, TCPL 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 TCPL, and Foothills was consolidated subsequent to that date.

TCPL 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 TCPL 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 TCPL sells power are accounted for as operating leases and, accordingly, the related plant, property and equipment are accounted for as assets under operating leases.

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 TCPL'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.

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 TCPL'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 18.

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 TCPL 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)[1]

Year ended December 31, 2004 (millions of dollars)	**Gas Transmission**	**Power**	**Corporate**	**Total**
Revenues	**3,917**	**1,190**	**—**	**5,107**
Cost of sales[2]	**—**	**(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 and preferred equity charges and non-controlling interests	**(785)**	**(9)**	**(81)**	**(875)**
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**	**(4)**	**978**
Discontinued operations				**52**
Net Income Applicable to Common Shares				**1,030**

Year ended December 31, 2003 (millions of dollars)	Gas Transmission	Power	Corporate	Total
Revenues	3,956	1,401	—	5,357
Cost of sales[2]	—	(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 and preferred equity 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 Applicable to Common Shares				851

Year ended December 31, 2002 (millions of dollars)	**Gas Transmission**	**Power**	**Corporate**	**Total**
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 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 Applicable to Common Shares				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	**892**	870
Continuing operations	**22,122**	20,687
Discontinued operations	**7**	11
	22,129	20,698

GEOGRAPHIC INFORMATION

Year ended December 31 (millions of dollars)	**2004**	**2003**	**2002[4]**
Revenues[3]			
Canada — domestic	**3,147**	3,257	2,731
Canada — export	**1,261**	1,293	1,641
United States	**699**	807	842
	5,107	5,357	5,214

(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
	18,704	17,415

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
	476	391	599

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
Gas Transmission						
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(1)						
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
Power(2)						
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
Corporate	**124**	**87**	**37**	122	72	50
	28,180	**9,476**	**18,704**	26,220	8,805	17,415

(1) TCPL 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[(1)]	**274**	278
PPAs — U.S.[(1)]	**98**	248
Pension and other benefit plans	**209**	201
Regulatory deferrals	**199**	212
Loans and advances[(2)]	**135**	111
Goodwill	**58**	—
Other	**251**	189
	1,477	1,357

(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

		TCPL's Proportionate Share				
		Income Before Income Taxes Year ended December 31			Net Assets December 31	
(millions of dollars)	Ownership Interest	2004	2003	2002	2004	2003
Gas Transmission						
Great Lakes	50.0% [(1)]	**86**	81	102	**379**	419
Iroquois	41.0% [(1)]	**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% [(1)]	**20**	11	21	**24**	25
Foothills	[(2)]	**—**	19	29	**—**	—
Other	Various	**6**	7	7	**27**	22
Power						
Power LP	30.6% [(3)]	**32**	25	26	**289**	234
ASTC Power Partnership	50.0% [(4)]	**—**	—	—	**93**	99
		207	209	252	**1,186**	1,175

(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 TCPL, 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 TCPL.

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**
Income			
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

Year ended December 31 (millions of dollars)	**2004**	**2003**	**2002**
Cash Flows			
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)

December 31 (millions of dollars)	**2004**	**2003**
Balance Sheet		
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

		TCPL's Share							
		Distributions from Equity Investments Year ended December 31			Income from Equity Investments Year ended December 31			Equity Investments December 31	
(millions of dollars)	Ownership Interest	2004	2003	2002	2004	2003	2002	2004	2003
Power									
Bruce Power	31.6%	—	—	—	**130**	99	—	**642**	513
Gas Transmission									
Northern Border	10.0% (1)	**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% (2)	—	10	—	—	14	2	—	—
Other	Various	**13**	6	1	**7**	3	1	**29**	37
		48	46	27	**171**	165	33	**840**	733

(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, TCPL 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)**
	1,202

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 TCPL 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, TCPL 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, TCPL 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 TCPL'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 TCPL at June 30, 2017. TCPL 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 TCPL'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[1]	Weighted Average Interest Rate[2]	Outstanding December 31[1]	Weighted Average Interest Rate[2]
CANADIAN MAINLINE[3]					
First Mortgage Pipe Line Bonds					
Pounds Sterling (2004 and 2003 — £25)	2007	**58**	**16.5%**	58	16.5%
Debentures					
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[8]		**—**		(60)	
		4,445		4,853	
ALBERTA SYSTEM[4]					
Debentures 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[8]		**—**		(16)	
		2,105		2,325	
GTN[5]					
Unsecured Debentures and Notes (2004 — US$525)	2005 to 2025	**632**	**7.2%**	—	
FOOTHILLS SYSTEM[3]					
Senior Secured Notes		—		80	4.3%
Senior Unsecured Notes	2009 to 2014	**400**	**4.9%**	300	4.7%
		400		380	
PORTLAND[6]					
Senior Secured Notes					
U.S. dollars (2004 — US$256; 2003 — US$271)	2018	**308**	**5.9%**	350	5.9%
OTHER					
Medium-Term Notes[3]					
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 Debentures[3]					
U.S. dollars (2004 and 2003 — US$57)	2006	**68**	**9.1%**	74	9.1%
Unsecured Loans, Debentures and Notes[7]					
U.S. dollars (2004 — US$1,082; 2003 — US$446)	2005 to 2034	**1,302**	**5.1%**	582	4.9%
		2,589		2,107	
		10,479		10,015	
Less: Current Portion of Long-Term Debt		**766**		550	
		9,713		9,465	

(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	**38**	34	34
	812	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[(1)]	Weighted Average Interest Rate[(2)]	Outstanding December 31[(1)]	Weighted Average Interest Rate[(2)]
Great Lakes					
Senior Unsecured Notes					
(2004 — US$235; 2003 — US$240)	2011 to 2030	**283**	**7.9%**	310	7.9%
Iroquois					
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%
Trans Québec & Maritimes					
Bonds	2005 to 2010	**143**	**7.3%**	143	7.3%
Term Loan	2006	**29**	**3.2%**	34	3.5%

TransCanada Power, L.P.					
Senior Unsecured Notes					
(2004 — US$58)	2014	**70**	**5.9%**	—	
Credit Facility	2009	**64**	**3.2%**	—	
Term Loan	2010	**2**	**11.3%**	—	
Other	2005 to 2012	**46**	**4.9%**	41	5.4%
		862		780	
Less: Current Portion of Non- Recourse					
Debt of Joint Ventures		**83**		19	
		779		761	

(1) Amounts outstanding represent TCPL'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, L.P. Credit Facility — 5.2 per cent.

The debt of joint ventures is non-recourse to TCPL. 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 TCPL, except to the extent of TCPL'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
	666	561

NOTE 12 PREFERRED SECURITIES

The US$460 million 8.25 per cent preferred securities are redeemable by the Company at par at any time. 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. 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 equity 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 equity component of preferred securities will be classified as debt.

NOTE 13 PREFERRED SHARES

December 31	Number of Shares (thousands)	Dividend Rate Per Share	Redemption Price Per Share	2004 (millions of dollars)	2003 (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 14 COMMON SHARES

	Number of Shares (thousands)	Amount (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	1,166	18
Outstanding at December 31, 2003 and 2004	**480,668**	**4,632**

Common Shares Issued and Outstanding

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

Restriction on Dividends

Certain terms of the Company's preferred shares, preferred securities, and debt instruments could restrict the Company's ability to declare dividends on preferred and common shares. At December 31, 2004, under the most restrictive provisions, approximately $1.4 billion was available for the payment of dividends on common shares.

NOTE 15 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)

		2004		2003	
December 31 (millions of dollars)	Accounting Treatment	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)

December 31 (millions of dollars)	Accounting Treatment	2004 Fair Value	2004 Notional or Notional Principal Amount	2003 Fair Value	2003 Notional or Notional Principal Amount
Foreign Exchange					
Cross-currency swaps					
(maturing 2010 to 2012)	Hedge	**(39)**	**U.S. 157**	(26)	U.S. 282
Interest Rate					
Interest rate swaps					
Canadian dollars					
(maturing 2005 to 2008)	Hedge	**7**	**145**	(1)	340
(maturing 2006 to 2009)	Non-hedge	**9**	**374**	10	624
		16		9	
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
		5		8	

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)		**2004**		**2003**	
December 31 (millions of dollars)	**Accounting Treatment**	**Fair Value**	**Notional or Notional Principal Amount**	**Fair Value**	**Notional or Notional Principal Amount**
Foreign Exchange					
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
Interest Rate					
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.

Power

Asset/(Liability)

December 31 (millions of dollars)	Accounting Treatment	2004 Fair Value	2003 Fair Value
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

		Power (GWh)[1]		Gas (Bcf)[1]	
December 31, 2004	Accounting Treatment	Purchases	Sales	Purchases	Sales
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

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

(1) TCPL 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 16 INCOME TAXES

Provision for Income Taxes

Year ended December 31 (millions of dollars)	2004	2003	2002
Current			
Canada	**390**	264	229
Foreign	**41**	41	41
	431	305	270
Future			
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	**1,253**	1,115	1,042
Foreign	**296**	281	280
Income from continuing operations before income taxes and non-controlling interests	**1,549**	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	**1,549**	1,396	1,322
Federal and provincial statutory tax rate	**33.9%**	36.7%	39.2%
Expected income tax expense	**525**	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	**(20)**	(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 17 NOTES PAYABLE

	2004		2003	
	Outstanding December 31 (millions of dollars)	Weighted Average Interest Rate Per Annum at December 31	Outstanding December 31 (millions of dollars)	Weighted Average Interest Rate Per Annum at December 31
Commercial Paper				
Canadian dollars	**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 18 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	**9**	**21**	**30**
Removal of Power LP redemption obligations	**—**	**(5)**	**(5)**
Accretion expense	**1**	**1**	**2**
Balance at December 31, 2004	**12**	**24**	**36**

NOTE 19 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.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2004**	**2003**	**2004**	**2003**
Change in Benefit Obligation				
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
Change in Plan Assets				
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	**5.75%**	6.00%	**6.00%**	6.25%
Rate of compensation increase	**3.50%**	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	**6.00%**	6.25%	6.75%	**6.25%**	6.50%	6.85%
Expected long-term rate of return on plan assets	**6.90%**	7.25%	7.52%			
Rate of compensation increase	**3.50%**	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 2004	2003	2002	Other Benefit Plans 2004	2003	2002
Current service cost	**28**	25	11	**3**	2	2
Interest cost	**58**	52	43	**7**	6	4
Actual return on plan assets	**(97)**	(89)	(9)	**1**	—	—
Actuarial loss	**46**	66	93	**(12)**	7	26
Plan amendment	**—**	—	92	**—**	—	7
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**35**	54	230	**(1)**	15	39
Difference between expected and actual return on plan assets	**39**	38	(36)	**(1)**	—	—
Difference between actuarial loss recognized and actual actuarial loss on accrued benefit obligation	**(32)**	(58)	(91)	**13**	(6)	(26)
Difference between amortization of past service costs and actual plan amendments	**3**	3	(92)	**—**	1	(7)
Amortization of transitional obligation related to regulated business	**—**	—	—	**2**	2	2
Net benefit cost recognized	**45**	37	11	**13**	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 2004	2003	Target Allocation 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 20 CHANGES IN OPERATING WORKING CAPITAL

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

NOTE 21 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 TCPL reached an agreement which governs TCPL'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, TCPL 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, TCPL 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 TCPL 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. TCPL'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.

TCPL 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 TCPL 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 TCPL. 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 22 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 23 U.S. GAAP (Restated[13])

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[1]

Year ended December 31 (millions of dollars)	**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[1]	**(353)**	(334)	(260)
Other expenses[2][12][13]	**806**	851	860
Dilution gain[12]	**(40)**	—	—
Income taxes	**490**	515	499
	903	1,032	1,099
Income from continuing operations — U.S. GAAP	**862**	813	764
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	**914**	863	764
Cumulative effect of the application of accounting changes, net of tax[3]	**—**	(13)	—
Net Income in Accordance with U.S. GAAP	**914**	850	764
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[4]	**72**	(2)	(40)
Unrealized gain/(loss) on derivatives, net of tax[5]	**1**	8	(4)
Comprehensive Income in Accordance with U.S. GAAP	**956**	802	721

Reconciliation of Income from Continuing Operations

Year ended December 31 (millions of dollars)	**Restated 2004**	**Restated 2003**	**Restated 2002**
Net Income from Continuing Operations in Accordance with Canadian GAAP	**1,031**	859	805
U.S. GAAP adjustments			
Preferred securities charges(6)	**(48)**	(57)	(58)
Tax impact of preferred securities charges	**17**	21	22
Unrealized (loss)/gain on foreign exchange and interest rate derivatives(5)	**(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(3)	**10**	28	(21)
Tax impact of unrealized gain/(loss) on energy marketing contracts	**(3)**	(10)	8
Equity loss(7)	**(2)**	(18)	—
Tax impact of equity loss	**—**	6	—
Amortization of deferred gains related to Power LP(12)(13)	**(3)**	(10)	(10)
Deferred gains related to Power LP(12)(13)	**(132)**	—	—
Income from Continuing Operations in Accordance with U.S. GAAP	**862**	813	764

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

Year ended December 31 (millions of dollars)	**2004**	**2003**	**2002**
Cash Generated from Operations			
Funds generated from continuing operations	**1,527**	1,619	1,610
Decrease in operating working capital	**44**	108	40
Net cash provided by continuing operations	**1,571**	1,727	1,650
Net cash (used in)/provided by discontinued operations	**(6)**	(17)	59
	1,565	1,710	1,709
Investing Activities			
Net cash used in investing activities	**(1,304)**	(943)	(796)
Financing Activities			
Net cash used in financing activities	**(333)**	(582)	(990)
Effect of Foreign Exchange Rate Changes on Cash and Short-Term Investments	**(87)**	(52)	(3)
(Decrease)/Increase in Cash and Short-Term Investments	**(159)**	133	(80)
Cash and Short-Term Investments			
Beginning of year	**282**	149	229
Cash and Short-Term Investments			
End of year	**123**	282	149

Condensed Balance Sheet in Accordance with U.S. GAAP[(1)]

December 31 (millions of dollars)	**2004**	**Restated 2003**
Current assets	**907**	1,017
Long-term investments[(7)(8)]	**1,887**	1,760
Plant, property and equipment	**17,083**	15,753
Regulatory asset[(9)]	**2,606**	2,721
Other assets	**1,235**	1,385
	23,718	22,636
Current liabilities[(10)]	**2,653**	2,179
Deferred amounts[(3)(5)(8)(12)(13)]	**803**	692
Long-term debt[(5)]	**9,753**	9,494
Deferred income taxes[(9)]	**3,048**	3,039
Preferred securities[(11)]	**554**	694
Non-controlling interests	**76**	82
Shareholders' equity[(12)(13)]	**6,831**	6,456
	23,718	22,636

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[4]	—	(40)	—	(40)
Unrealized loss on derivatives, net of tax of $(1)[5]	—	—	(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[4]	—	(2)	—	(2)
Unrealized gain on derivatives, net of tax of nil[5]	—	—	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)[4]	—	72	—	72
Unrealized gain on derivatives, net of tax of $(3)[5]	—	—	1	1
Foreign currency translation adjustment, net of tax of $(44)	(31)	—	—	(31)
Balance at December 31, 2004	(71)	(26)	(4)	(101)

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

(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, TCPL 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:

December 31 (millions of dollars)	2004	2003	2002
Decrease in:			
Income from continuing operations	**135**	10	10
Net income	**135**	10	10

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
Deferred Tax Liabilities		
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
	3,233	3,235
Deferred Tax Assets		
Net operating and capital loss carryforwards	**7**	28
Deferred amounts	**89**	79
Other	**106**	113
	202	220
Less: Valuation allowance	**17**	24
	185	196
Net deferred tax liabilities	**3,048**	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**
Income			
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

December 31 (millions of dollars)	**2004**	**2003**
Balance Sheet		
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