TRANSCANADA PIPELINES LIMITED

FOURTH QUARTER 2003

Quarterly Report

Consolidated Results-at-a-Glance

(unaudited) (millions of dollars)	Three months ended December 31 **2003**	 2002	Year ended December 31 **2003**	 2002
Net Income Applicable to Common Shares				
Continuing operations	**193**	180	**801**	747
Discontinued operations	**-**	-	**50**	-
	193	180	**851**	747

Management's Discussion and Analysis

The following discussion and analysis should be read in conjunction with the accompanying unaudited consolidated financial statements of TransCanada PipeLines Limited (TCPL or the company) for the year ended December 31, 2003 and the notes thereto.

Results of Operations

Consolidated

TCPL's net income applicable to common shares from continuing operations (net earnings) and net income for fourth quarter 2003 were $193 million compared to $180 million for fourth quarter 2002. The increase of $13 million was primarily due to higher earnings from the Power business. Higher net earnings from the Power business included $7 million after tax from TCPL's investment in Bruce Power L.P. (Bruce Power) and lower general, administrative and support costs.

TCPL's net income applicable to common shares for the year ended December 31, 2003 was $851 million compared to $747 million for the comparable period in 2002. Included in 2003 was net income from discontinued operations of $50 million reflecting the third quarter 2003 income recognition of a portion of the initially deferred gain of approximately $100 million after tax relating to the 2001 disposition of the company's Gas Marketing business.

TCPL's net earnings applicable to common shares from continuing operations for the year ended December 31, 2003 were $801 million compared to $747 million for the comparable period in 2002. The increase of $54 million in 2003 compared to 2002 was primarily due to higher net earnings of $74 million from the Power business and lower net expenses in the Corporate segment, partially offset by lower net earnings from the Gas Transmission business.

Net earnings from the Power business for the year ended December 31, 2003 included $73 million after tax from TCPL's investment in Bruce Power which was acquired in February 2003 and a $19 million positive after-tax earnings impact of a June 2003 settlement with a former counterparty which defaulted in 2001 under power forward contracts. This amount represents the value of power forward contracts terminated at the time of the counterparty's default. These increases were partially offset by reduced operating and other income from the Northeastern U.S. Operations, combined with higher general, administrative and support costs.

The $11 million decrease in 2003 net expenses in the Corporate segment was primarily due to the positive impacts of a weaker U.S. dollar in 2003 compared to 2002.

The lower net earnings of $31 million in the Gas Transmission business for the year ended December 31, 2003 compared to the prior year were primarily due to the decline in the Alberta System's 2003 net earnings, reflecting the one-year fixed revenue requirement settlement reached between TCPL and its stakeholders in February 2003. In June 2002, TCPL received the National Energy Board (NEB) decision on its Fair Return application (Fair Return decision) to determine the cost of capital to be included in the calculation of 2001 and 2002 final tolls on its Canadian Mainline. The results for the year ended December 31, 2002 included after-tax income of $16 million representing the impact of the Fair Return decision for 2001. The 2003 results for the Gas Transmission segment included TCPL's $11 million share of future income tax benefits recognized by TransGas de Occidente (TransGas) while the 2002 results included TCPL's $7 million share of a favourable ruling for Great Lakes related to Minnesota use tax paid in prior years.

Segment Results-at-a-Glance

(unaudited)	Three months ended December 31		Year ended December 31	
(millions of dollars)	**2003**	2002	**2003**	2002
Gas Transmission	**160**	162	**622**	653
Power	**44**	30	**220**	146
Corporate	**(11)**	(12)	**(41)**	(52)
Continuing operations	**193**	180	**801**	747
Discontinued operations	**-**	-	**50**	-
Net Income Applicable to Common Shares	**193**	180	**851**	747

Funds generated from continuing operations of $403 million for fourth quarter 2003 decreased $64 million compared to fourth quarter 2002. Funds generated from continuing operations of $1,810 million for the year ended December 31, 2003 decreased $17 million compared to last year.

Gas Transmission

The Gas Transmission business generated net earnings of $160 million and $622 million for the quarter and year ended December 31, 2003, respectively, compared to $162 million and $653 million for the same periods in 2002.

Gas Transmission Results-at-a-Glance

(unaudited)	Three months ended December 31		Year ended December 31	
(millions of dollars)	**2003**	2002	**2003**	2002
Wholly-Owned Pipelines				
Alberta System	**54**	56	**190**	214
Canadian Mainline	**75**	75	**290**	307
Foothills*	**6**	4	**20**	17
BC System	**2**	2	**6**	6
	137	137	**506**	544
Other Gas Transmission				
Great Lakes	**14**	17	**52**	66
Iroquois	**3**	3	**18**	18
TC PipeLines, LP	**4**	5	**15**	17
Portland**	**4**	-	**11**	2
Ventures LP	**3**	2	**10**	7
Trans Québec & Maritimes	**2**	2	**8**	8
CrossAlta	**2**	4	**6**	13
TransGas de Occidente	**2**	1	**22**	6
Northern Development	**(2)**	(1)	**(4)**	(6)
General, administrative, support and other	**(9)**	(8)	**(22)**	(22)
	23	25	**116**	109
Net earnings	**160**	162	**622**	653

* The remaining interests in Foothills, previously not held by TCPL, were acquired on August 15, 2003.

** TCPL increased its ownership interest in Portland from 33.3 per cent to 43.4 per cent on September 29, 2003 and from 43.4 per cent to 61.7 per cent on December 3, 2003.

Wholly-Owned Pipelines

The Alberta System's net earnings of $54 million in fourth quarter 2003 decreased $2 million compared to $56 million in the same quarter of 2002. Net earnings for the year ended December 31, 2003 decreased $24 million compared to the prior year. This decrease is primarily due to lower earnings from the one-year 2003 Alberta System Revenue Requirement Settlement (the 2003 Settlement) reached in February 2003. The 2003 Settlement includes a fixed revenue requirement component, before non-routine adjustments, of $1.277 billion compared to $1.347 billion in 2002. As discussed in the third quarter 2003 Quarterly Report to Shareholders, the lower negotiated 2003 revenue requirement was expected to reduce 2003 earnings by approximately $30 million relative to 2002 earnings of $214 million. However, lower financing and operating costs partially offset the previously anticipated reduction in earnings.

The Canadian Mainline's fourth quarter net earnings of $75 million are consistent with net earnings in the same quarter of 2002. The 2003 net earnings of $290 million are $17 million lower than 2002 net earnings due to the impact of the NEB's Fair Return decision in 2002. This decision included an increase in the deemed common equity ratio from 30 to 33 per cent effective January 1, 2001 and resulted in additional net earnings of $16 million for the year ended December 31, 2001, recognized in June 2002. The impact of a lower average investment base was substantially offset by an increase in the approved rate of return on common equity from 9.53 per cent in 2002 to 9.79 per cent in 2003.

In December 2002, the NEB approved TCPL's application to charge interim tolls for transportation service, effective January 1, 2003. In August 2003, subsequent to the NEB's decision on the 2003 Tolls and Tariff Application, it approved interim tolls that the company charged from September 1, 2003 to December 31, 2003. The NEB ordered that tolls will remain interim pending a decision from the Federal Court of Appeal on TCPL's appeal of the NEB's decision on TCPL's Fair Return Review and Variance Application, which is expected to be heard commencing February 16, 2004.

Operating Statistics

Year ended December 31 (unaudited)	Alberta System*		Canadian Mainline**		Foothills***		BC System	
	2003	2002	**2003**	2002	**2003**	2002	**2003**	2002
Average investment base ($ millions)	**4,878**	5,074	**8,565**	8,884	**739**	***	**236**	211
Delivery volumes (Bcf)								
Total	**3,883**	4,146	**2,628**	2,630	**1,110**	***	**325**	371
Average per day	**10.6**	11.4	**7.2**	7.2	**3.0**	***	**0.9**	1.0

* Field receipt volumes for the Alberta System for the year ended December 31, 2003 were 3,892 Bcf (2002 - 4,101 Bcf); average per day was 10.7 Bcf (2002 - 11.2 Bcf).
** Canadian Mainline deliveries originating at the Alberta border and in Saskatchewan for the year ended December 31, 2003 were 2,055 Bcf (2002 - 2,221 Bcf); average per day was 5.6 Bcf (2002 - 6.1 Bcf).
*** The remaining interests in Foothills were acquired in August 2003. The annual 2003 delivery volumes in the table represent 100 per cent of Foothills.

Other Gas Transmission

TCPL's proportionate share of net earnings from Other Gas Transmission was $23 million and $116 million for the quarter and year ended December 31, 2003, respectively.

Net earnings for fourth quarter 2003 were slightly lower than the same quarter in 2002. Higher contributions from Portland, Ventures LP and TransGas were more than offset by lower earnings from CrossAlta, higher project development costs, and the impact of a weaker U.S. dollar.

The 2002 results included TCPL's $7 million share of a favourable ruling for Great Lakes related to Minnesota use tax paid in prior years. Excluding the impact of the Great Lakes ruling in 2002, net earnings for 2003 increased $14 million compared to 2002. Earnings from TransGas were $16 million higher as a result of higher contractual tolls and the recognition of future tax benefits in 2003. TCPL's share of Portland's net earnings in 2003 has increased $9 million compared to last year primarily due to the impacts of a rate settlement in early 2003 and TCPL's increased ownership interest in 2003. These increases were partially offset by a weaker U.S. dollar and lower earnings from CrossAlta due to reduced storage margins as a result of unfavourable market conditions.

On December 3, 2003, TCPL increased its ownership interest in Portland Natural Gas Transmission System Partnership (Portland) from 43.4 per cent to 61.7 per cent. The company acquired the additional interest from El Paso Corporation for US$82 million, including US$50 million of assumed debt.

Power

Power Results-at-a-Glance

(unaudited)	Three months ended December 31		Year ended December 31	
(millions of dollars)	**2003**	2002	**2003**	2002
Western operations	**31**	30	**160**	131
Northeastern U.S. operations	**36**	35	**127**	149
Bruce Power L.P. investment	**7**	-	**99**	-
Power LP investment	**9**	9	**35**	36
General, administrative and support costs	**(20)**	(25)	**(86)**	(73)
Operating and other income	**63**	49	**335**	243
Financial charges	**(4)**	(4)	**(12)**	(13)
Income taxes	**(15)**	(15)	**(103)**	(84)
Net earnings	**44**	30	**220**	146

Power's net earnings in fourth quarter 2003 of $44 million increased $14 million compared to $30 million in fourth quarter 2002. Earnings from the February 2003 acquisition of the 31.6 per cent interest in Bruce Power and reduced general, administrative and support costs were the primary reasons for the increase.

Net earnings for the year ended December 31, 2003 of $220 million were $74 million higher compared to the prior year. Bruce Power earnings, a second quarter 2003 settlement in Western Operations for the value of power forward contracts terminated with a former counterparty and the addition of the ManChief plant in late 2002 were the primary reasons for the increase. Partially offsetting the increase were lower earnings from the Northeastern U.S. Operations and higher general, administrative and support costs.

Western Operations

Operating and other income for fourth quarter 2003 in Western Operations of $31 million was comparable to fourth quarter 2002. Higher contributions from the Sundance power purchase arrangements reflecting lower transmission costs were partially offset by the unfavourable effects in fourth quarter 2003 of lower prices achieved on the overall sale of power.

Operating and other income for the year ended December 31, 2003 in Western Operations of $160 million was $29 million higher compared to the prior year, mainly due to a $31 million pre-tax ($19 million after tax) positive earnings impact related to a June 2003 settlement with a former counterparty which defaulted in 2001 under power forward contracts. A full year of earnings from the ManChief plant, acquired in late 2002, and higher contributions from the Sundance power purchase arrangements reflecting lower transmission costs also contributed to higher operating income. Partially offsetting these increases were the effects in 2003 of lower prices achieved on the overall sale of power and the higher cost of natural gas fuel at the carbon black facility.

Northeastern U.S. Operations

Operating and other income for fourth quarter 2003 in Northeastern U.S. Operations of $36 million increased marginally compared to fourth quarter 2002. Increased water flows through the Curtis Palmer hydroelectric facility and earnings from the Cobourg temporary generation facility were partially offset by the unfavourable impact of a weaker U.S. dollar and higher natural gas fuel cost at Ocean State Power (OSP) resulting from an arbitration process.

Operating and other income for the year ended December 31, 2003 in Northeastern U.S. Operations of $127 million decreased $22 million compared to 2002 primarily due to the impact of higher operating costs at OSP and the unfavourable impact of a weaker U.S. dollar. Partially offsetting these decreases were incremental earnings from the growth in volumes and margins in the Northeastern U.S. retail business with large commercial and industrial customers. The long- term gas supply for OSP is subject to a yearly price renegotiation, taking effect after the tenth year of the contract. If OSP and the suppliers are unable to reach an agreement on price in a given year, the matter is settled by arbitration. OSP is currently in arbitration with its natural gas fuel suppliers regarding changes to the pricing of its fuel supply.

Bruce Power L.P. Investment

Bruce Power Results-at-a-Glance

(unaudited) (millions of dollars)	Three months ended December 31, 2003	Year ended December 31, 2003
Bruce Power (100 per cent basis)		
Revenues	269	1,208
Operating expenses	254	853
Operating income	15	355
Financial charges	20	69
(Loss)/Income before income taxes	(5)	286
TCPL's interest in Bruce Power (loss)/income before income taxes*	(1)	65
Adjustments **	8	34
TCPL's income from Bruce Power before income taxes	7	99

* TCPL acquired its interest in Bruce Power on February 14, 2003. Bruce Power's 100 per cent income before income taxes from February 14, 2003 to December 31, 2003 was $205 million.
** See Note 7 to the December 31, 2003 financial statements for an explanation of the amounts included in Adjustments.

Bruce Power contributed $7 million of pre-tax equity income in fourth quarter 2003 compared to $38 million in third quarter 2003. The decrease reflected lower power output and higher maintenance costs compared to third quarter 2003, primarily due to a maintenance outage at one of the Bruce B units for the entire fourth quarter 2003. Overall prices achieved during fourth quarter 2003 were approximately $45 per megawatt hour (MWh) which is consistent with third quarter 2003. The average price achieved for the year ended December 31, 2003 was approximately $48 per MWh. Approximately 30 per cent of the output was sold into Ontario's wholesale spot market in fourth quarter 2003 with the remainder being sold under longer term contracts.

TCPL's share of power output for fourth quarter 2003 from four Bruce B units and one Bruce A unit was 1,846 gigawatt hours (GWh) compared to 2,041 GWh in third quarter 2003. This includes power output from Bruce A Unit 4 from November 1, 2003 to December 31, 2003 of approximately 275 GWh. Bruce A Unit 4 began producing electricity to the Ontario electricity grid on October 7, 2003 and was considered commercially in-service November 1, 2003. Bruce B Unit 8 was offline for the entire fourth quarter for maintenance. As well, Bruce B Unit 7 incurred a week long forced outage in the fourth quarter. The Bruce units ran at an average availability of 73 per cent in the fourth quarter. The average availability during TCPL's period of ownership ending December 31, 2003 was 83 per cent.

Bruce A Unit 3 reconnected to the Ontario electricity grid on January 8, 2004. Similar to the Bruce A Unit 4 startup process, after performing and evaluating tests of the shutdown system, Bruce A Unit 3 is expected to reconnect to the grid and begin ramping up to full power. Bruce Power's cumulative restart cost for the two Bruce A units was approximately $720 million. Bruce Power incurred approximately $300 million on the two unit restart program for the period February 14, 2003 to December 31, 2003, of which approximately $32 million was incurred in fourth quarter 2003. TCPL did not provide any funding to Bruce Power subsequent to the acquisition of its ownership interest in February 2003. The two Bruce A units add 1,500 megawatts (MW) of capacity bringing Bruce Power's total capacity to 4,660 MW.

Bruce Power spent approximately $147 million on capital expenditures at Bruce B for the period February 14, 2003 to December 31, 2003, the majority of which was for safety systems and power uprate programs. In 2004, Bruce Power's capital expenditure program for the two Bruce A and four Bruce B reactors is expected to total approximately $400 million.

Equity income from Bruce Power is directly impacted by fluctuations in wholesale spot market prices for electricity as well as overall plant availability, which in turn, is impacted by scheduled and unscheduled maintenance. To reduce its exposure to spot market prices, Bruce Power has entered into fixed price sales contracts for approximately 1,560 MW of output for 2004. The average availability in 2004 for the six Bruce units is expected to be 80 per cent compared to 85 per cent for the year ended December 31, 2003. This decrease reflects planned maintenance outages for two Bruce B and two Bruce A units and a test of the Bruce B vacuum building expected in the fall, which will require all four Bruce B units to be taken offline for approximately one month. There is a planned maintenance outage at one of the Bruce A units for approximately one month, towards the end of first quarter 2004.

Power LP Investment

Operating and other income of $9 million and $35 million for the three and twelve months ended December 31, 2003, was consistent with the same periods in 2002.

General, Administrative and Support Costs

General, administrative and support costs for fourth quarter 2003 of $20 million were $5 million lower compared to fourth quarter 2002. The decrease is primarily due to lower business development costs in fourth quarter 2003.

General, administrative and support costs for the year ended December 31, 2003 increased $13 million compared to the prior year, mainly reflecting higher support costs as part of the company's continued investment in Power.

Power Sales Volumes

(unaudited)	Three months ended December 31		Year ended December 31	
(GWh)	**2003**	2002	**2003**	2002
Western operations*	**2,972**	2,864	**12,296**	12,065
Northeastern U.S. operations	**1,794**	1,513	**6,906**	5,630
Bruce Power L.P. investment**	**1,846**	n/a	**6,655**	n/a
Power LP investment	**549**	637	**2,153**	2,416
Total	**7,161**	5,014	**28,010**	20,111

* Sales volumes include TCPL's share of the Sundance B power purchase arrangement (50 per cent).
** Acquired in February 2003. Sales volumes reflect TCPL's share of Bruce Power output (31.6 per cent) for the period February 14, 2003 to December 31, 2003.

Weighted Average Plant Availability*	Three months ended December 31		Year ended December 31	
(unaudited)	**2003**	2002	**2003**	2002
Western operations	**94%**	99%	**93%**	99%
Northeastern U.S. operations	**99%**	82%	**94%**	95%
Bruce Power L.P. investment**	**73%**	n/a	**83%**	n/a
Power LP investment	**98%**	98%	**96%**	94%
All plants	**89%**	92%	**90%**	96%

* Plant availability is reduced by planned and unplanned outages.
** Acquired in February 2003. TCPL's availability reflects the period February 14, 2003 to December 31, 2003.

Corporate

Net expenses were $11 million and $12 million for the three months ended December 31, 2003 and 2002, respectively. Net expenses were $41 million for the year ended December 31, 2003 compared to $52 million for 2002. The $11 million decrease in net expenses for 2003 is primarily due to the positive impacts of a weaker U.S. dollar compared to the prior year. These positive impacts substantially offset the negative impacts of a weaker U.S. dollar reflected in the other segments.

Discontinued Operations

The company's exit from the Gas Marketing business was substantially completed by December 31, 2001. In third quarter 2003, $50 million of the original approximately $100 million after-tax deferred gain related to Gas Marketing was recognized in income. At December 31, 2003, TCPL reviewed the provision for loss on discontinued operations and the deferred gain and concluded that the remaining provision was adequate and the deferral of the remaining approximately $50 million of deferred after-tax gain related to the Gas Marketing business was appropriate.

TCPL's investments in Gasoducto del Pacifico, INNERGY Holdings S.A. and P.T. Paiton Energy Company, which were approved for disposal under a plan in December 1999, will be accounted for as part of continuing operations as of December 31, 2003 due to the length of time it has taken the company to dispose of these assets. It is the intention of the company to continue with the plan to dispose of these investments.

Liquidity and Capital Resources

Funds Generated from Operations

Funds generated from continuing operations were $403 million and $1,810 million for the three and twelve months ended December 31, 2003, respectively, compared with $467 million and $1,827 million for the same periods in 2002.

TCPL expects that its ability to generate sufficient amounts of cash in the short term and the long term, when needed, and to maintain financial capacity and flexibility to provide for planned growth is adequate and remains substantially unchanged since December 31, 2002.

Investing Activities

In the three months and year ended December 31, 2003, capital expenditures, excluding acquisitions, totalled $127 million (2002 - $202 million) and $391 million (2002 - $599 million), respectively, and related primarily to Iroquois' ongoing Eastchester Expansion project into New York City, maintenance and capacity capital in wholly-owned pipelines and construction of the MacKay River power plant in Alberta.

Acquisitions for the year ended December 31, 2003 totalled $570 million (2002 – $228 million) and were primarily comprised of:

- in fourth quarter 2003, the increase in interest in Portland from 43.4 per cent to 61.7 per cent for approximately US$32 million,
- in third quarter 2003, the increase in interest in Portland from 33.3 per cent to 43.4 per cent for approximately US$19 million,
- in third quarter 2003, the acquisition of the remaining interests in Foothills for approximately $105 million, and
- in first quarter 2003, the acquisition of a 31.6 per cent interest in Bruce Power for approximately $409 million including closing adjustments.

In addition, TCPL assumed $154 million and US$78 million of debt on the Foothills and Portland acquisitions, respectively.

Financing Activities

TCPL used a portion of its cash resources to retire long-term debt of $358 million and $744 million in the quarter and year ended December 31, 2003, respectively. In November 2003, the company issued $450 million of ten year notes bearing interest at 5.65 per cent and in June 2003, the company issued US$350 million of ten year notes bearing interest at 4.00 per cent. For the year ended December 31, 2003, outstanding notes payable decreased by $62 million, while cash and short-term investments increased by $126 million.

In July 2003, TCPL redeemed all of its outstanding US$160 million, 8.75 per cent Junior Subordinated Debentures, also known as Cumulative Trust Originated Preferred Securities. Holders of these debentures received US$25.0122 per US$25.00 of the principal amount, which included accrued and unpaid interest to the redemption date.

Dividends

On January 27, 2004, TCPL's Board of Directors declared a dividend for the quarter ending March 31, 2004 in an aggregate amount equal to the aggregate quarterly dividend to be paid on April 30, 2004 by TransCanada Corporation on the issued and outstanding common shares as at the close of business on March 31, 2004. The Board also declared regular dividends on TCPL's preferred shares.

Risk Management

With respect to continuing operations, TCPL's market, financial and counterparty risks remain substantially unchanged since December 31, 2002. See explanation for discontinued operations' risk management activity under Results of Operations – Discontinued Operations. For further information on risks, refer to Management's Discussion and Analysis in TransCanada PipeLines Limited's 2002 Annual Report.

The processes within TCPL's risk management function are designed to ensure that risks are properly identified, quantified, reported and managed. Risk management strategies, policies and limits are designed to ensure TCPL's risk-taking is consistent with its business objectives and risk tolerance. Risks are managed within limits ultimately established by the Board of Directors and implemented by senior management, monitored by risk management personnel and audited by internal audit personnel.

TCPL manages market and financial risk exposures in accordance with its corporate market risk policy and position limits. The company's primary market risks result from volatility in commodity prices, interest rates and foreign currency exchange rates. TCPL's counterparty risk exposure results from the failure of a counterparty to meet its contractual financial obligations, and is managed in accordance with its corporate counterparty risk policy.

Controls and Procedures

As of the end of the period covered by this quarterly report, TCPL's management, together with TCPL's President and Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of the company's disclosure controls and procedures. Based on this evaluation, the President and Chief Executive Officer and the Chief Financial Officer of TCPL have concluded that the disclosure controls and procedures are effective.

There were no changes in TCPL's internal control over financial reporting during the most recent fiscal quarter that have materially affected or are reasonably likely to materially affect TCPL's internal control over financial reporting.

Critical Accounting Policy

TCPL's critical accounting policy, which remains unchanged since December 31, 2002, is the use of regulatory accounting for its regulated operations. For further information on this critical accounting policy, refer to Management's Discussion and Analysis in TransCanada PipeLines Limited's 2002 Annual Report.

Critical Accounting Estimates

Since a determination of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of the company's consolidated financial statements requires the use of estimates and assumptions which have been made using careful judgment. TCPL's critical accounting estimates from December 31, 2002 continue to be depreciation expense and certain deferred after-tax gains and remaining obligations related to the Gas Marketing business. For further information on these critical accounting estimates, refer to Results of Operations – Discontinued Operations and to Management's Discussion and Analysis in TransCanada PipeLines Limited's 2002 Annual Report.

Outlook

In 2004, the outcome of regulatory proceedings could have a significant impact on the expected results for the Alberta System and Canadian Mainline. Plant availability and fluctuating power prices could have a significant impact on Power results. Excluding these impacts as well as the settlement with a former counterparty in 2003 and the recognition of the TransGas future tax benefits in 2003, the outlook for the company is relatively unchanged since December 31, 2002. For further information on outlook, refer to Management's Discussion and Analysis in TransCanada PipeLines Limited's 2002 Annual Report.

The company's net earnings and cash flow combined with a strong balance sheet continue to provide the financial flexibility for TCPL to make disciplined investments in its core businesses of Gas Transmission and Power. The strengthening of the Canadian dollar compared to the U.S. dollar in 2003 has not significantly impacted TCPL's consolidated financial results in 2003 and is not expected to have a significant impact in 2004. Credit ratings on TCPL's senior unsecured debt assigned by Dominion Bond Rating Service Limited (DBRS), Moody's Investors Service (Moody's) and Standard & Poor's are currently A, A2 and A-, respectively. DBRS and Moody's both maintain a 'stable' outlook on their ratings and Standard & Poor's maintains a 'negative' outlook on its rating.

Other Recent Developments

Gas Transmission

Wholly-Owned Pipelines

Alberta System

In July 2003, TCPL, along with other utilities, filed evidence in the Generic Cost of Capital (GCOC) Proceeding with the Alberta Energy and Utilities Board (EUB). TCPL has requested a return on equity of 11 per cent based on a deemed common equity of 40 per cent in its GCOC Application. The EUB expects to adopt a standardized approach to determining the rate of return and capital structure for all utilities under its jurisdiction at the conclusion of this proceeding. The oral portion of the hearing was completed on January 16, 2004 with written arguments to follow.

In September 2003, TCPL filed Phase I of the 2004 General Rate Application (GRA) with the EUB, consisting of evidence in support of the applied for rate base and revenue requirement. The company applied for a composite depreciation rate of 4.13 per cent compared to the current depreciation rate of 4.00 per cent. Phase II of the application, dealing primarily with rate design and services, was filed in December 2003. EUB hearings to consider the 2004 GRA Phase I and Phase II applications are scheduled to commence, in Calgary, on April 1, 2004 and June 1, 2004, respectively.

In December 2003, the EUB approved TCPL's application to charge interim tolls for transportation service, effective January 1, 2004. Final tolls for 2004 will be determined based on the EUB decisions for the GCOC hearing and both phases of the GRA.

On December 1 and 2, 2003, two natural gas pipeline failures occurred on the Alberta System. Deliveries of gas to local communities were not impacted as a result of either incident. Following preliminary investigations into the causes of the two pipeline ruptures, TCPL found evidence of external corrosion on the pipeline. No one was injured and the impacted segment of the Alberta System was repaired within days. The incidents are not expected to have an impact on the company's earnings.

Canadian Mainline

In July 2003, TCPL filed a notice of appeal with the Federal Court of Appeal and served notice of appeal on parties to the NEB proceeding on TCPL's Fair Return Review and Variance Application. In September 2003, TCPL filed a Memorandum of Fact and Law with the Federal Court of Appeal, and in October 2003 all interested parties filed their memoranda in response to TCPL's filing. The case will be heard in an oral hearing scheduled to commence February 16, 2004.

In December 2003, the NEB approved interim tolls effective January 1, 2004 for the Canadian Mainline. The 2004 Tolls and Tariff Application for the Canadian Mainline was filed on January 26, 2004 and includes a request for an 11 per cent return on a 40 per cent deemed common equity component.

Other Gas Transmission

Iroquois

Iroquois continues to make progress on the construction of the Eastchester expansion project and is expected to place the expansion facilities into service in February 2004.

Northern Development

For the Mackenzie Gas Pipeline Project, TCPL has agreed to finance the Aboriginal PipeLine Group (APG) for its one-third share of project definition phase costs which is estimated to be approximately $90 million over three years. In the year ended December 31, 2003, TCPL funded $34 million which is included in Other Assets. Regulatory applications for the Mackenzie Gas Pipeline Project have been delayed and are expected to be filed mid-2004.

Liquefied Natural Gas

In September 2003, TCPL and ConocoPhillips Company announced the Fairwinds partnership to jointly evaluate a site in Harpswell, Maine for the development of a liquefied natural gas (LNG) regasification facility. The residents of the Town of Harpswell are expected to vote in first quarter 2004 on leasing a town-owned site for the facility. If leasing of the site is approved and necessary regulatory approvals are subsequently received, construction of the LNG facility could begin in 2006 with the facility becoming operational in 2009. Natural gas from the LNG facility would be delivered by pipeline to markets in the northeast U.S.

Power

In August 2003, TCPL successfully commenced operations under a fee-for-service power purchase arrangement with the Ontario government through the Ontario Electricity Financial Corporation (OEFC). Under the agreement, TCPL supplied 110 MW of capacity from a temporary facility adjacent to the Canadian Mainline near Cobourg, Ontario up to December 31, 2003. Demobilization of the temporary facility began in early January 2004 and is expected to be complete by late spring.

On October 24, 2003, TCPL and Grandview Cogeneration Corporation, an affiliate of Irving Oil Limited (Irving), announced an agreement to build a 90 MW natural gas-fired cogeneration power plant in Saint John, New Brunswick. This cogeneration facility will be developed and owned by TCPL. Under a 20 year tolling arrangement, Irving will provide fuel for the plant and contract for 100 per cent of the plant's heat and electricity output. Construction of the plant commenced in December 2003 and is expected to be in-service in December 2004.

Construction of MacKay River, a 165 MW facility near Fort McMurray, Alberta, was completed in fourth quarter 2003 and commissioning is underway.

The fourth quarter scheduled maintenance outage of Bruce B Unit 8 was originally planned to take approximately eight weeks, but was extended after inspections identified some erosion on support plates in three of the unit's eight steam generators. Repairs have been completed and approved by the Canadian Nuclear Safety Commission and the unit is in the process of being returned to service.

Forward-Looking Information

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

Consolidated Income

(unaudited) (millions of dollars)	Three months ended December 31 **2003**	 2002	Year ended December 31 **2003**	 2002
Revenues	**1,319**	1,338	**5,357**	5,214
Operating Expenses				
Cost of sales	**159**	161	**692**	627
Other costs and expenses	**434**	423	**1,682**	1,546
Depreciation	**222**	217	**914**	848
	815	801	**3,288**	3,021
Operating Income	**504**	537	**2,069**	2,193
Other Expenses/(Income)				
Financial charges	**202**	215	**821**	867
Financial charges of joint ventures	**14**	23	**77**	90
Equity income	**(14)**	(7)	**(165)**	(33)
Interest and other income	**(16)**	(17)	**(60)**	(53)
	186	214	**673**	871
Income from Continuing Operations before Income Taxes and Non-Controlling Interests	**318**	323	**1,396**	1,322
Income Taxes - Current and Future	**108**	128	**535**	517
Non-Controlling Interests	**2**	-	**2**	-
Net Income from Continuing Operations	**208**	195	**859**	805
Net Income from Discontinued Operations	**-**	-	**50**	-
Net Income	**208**	195	**909**	805
Preferred Securities Charges	**10**	10	**36**	36
Preferred Share Dividends	**5**	5	**22**	22
Net Income Applicable to Common Shares	**193**	180	**851**	747
Net Income Applicable to Common Shares				
Continuing operations	**193**	180	**801**	747
Discontinued operations	**-**	-	**50**	-
	193	180	**851**	747

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Cash Flows

(unaudited) (millions of dollars)	Three months ended December 31 **2003**	 2002	Year ended December 31 **2003**	 2002
Cash Generated From Operations				
Net income from continuing operations	**208**	195	**859**	805
Depreciation	**222**	217	**914**	848
Future income taxes	**(18)**	67	**230**	247
Equity income in excess of distributions received	**(3)**	-	**(128)**	(6)
Other	**(6)**	(12)	**(65)**	(67)
Funds generated from continuing operations	**403**	467	**1,810**	1,827
Decrease in operating working capital	**29**	101	**112**	33
Net cash provided by continuing operations	**432**	568	**1,922**	1,860
Net cash provided by/(used in) discontinued operations	**-**	29	**(17)**	59
	432	597	**1,905**	1,919
Investing Activities				
Capital expenditures	**(127)**	(202)	**(391)**	(599)
Acquisitions, net of cash acquired	**(23)**	(209)	**(570)**	(228)
Deferred amounts and other	**43**	(103)	**(190)**	(115)
Net cash used in investing activities	**(107)**	(514)	**(1,151)**	(942)
Financing Activities				
Dividends and preferred securities charges	**(150)**	(139)	**(588)**	(546)
Advances from parent	**39**	-	**46**	-
Notes payable (repaid)/issued, net	**(341)**	182	**(62)**	(46)
Long-term debt issued	**455**	-	**930**	-
Reduction of long-term debt	**(358)**	(256)	**(744)**	(486)
Non-recourse debt of joint ventures issued	**-**	20	**60**	44
Reduction of non-recourse debt of joint ventures	**(16)**	(29)	**(71)**	(80)
Redemption of junior subordinated debentures	**-**	-	**(218)**	-
Common shares issued	**-**	7	**18**	50
Net cash used in financing activities	**(371)**	(215)	**(629)**	(1,064)
(Decrease)/Increase in Cash and Short-Term Investments	**(46)**	(132)	**125**	(87)
Cash and Short-Term Investments				
Beginning of period	**383**	344	**212**	299
Cash and Short-Term Investments				
End of period	**337**	212	**337**	212
Supplementary Cash Flow Information				
Income taxes paid	**28**	52	**220**	257
Interest paid	**222**	227	**846**	866

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Balance Sheet

(unaudited)

December 31 (millions of dollars)	**2003**	2002
ASSETS		
Current Assets		
Cash and short-term investments	**337**	212
Accounts receivable	**603**	691
Inventories	**165**	178
Other	**88**	107
	1,193	1,188
Long-Term Investments	**733**	345
Plant, Property and Equipment	**17,451**	17,496
Other Assets	**1,164**	937
	20,541	19,966
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable	**367**	297
Accounts payable	**1,069**	990
Accrued interest	**208**	227
Current portion of long-term debt	**550**	517
Current portion of non-recourse debt of joint ventures	**19**	75
	2,213	2,106
Deferred Amounts	**466**	549
Long-Term Debt	**9,465**	8,815
Future Income Taxes	**427**	226
Non-Recourse Debt of Joint Ventures	**761**	1,222
Junior Subordinated Debentures	**22**	238
	13,354	13,156
Non-Controlling Interests	**82**	-
Shareholders' Equity		
Preferred securities	**672**	674
Preferred shares	**389**	389
Common shares	**4,632**	4,614
Contributed surplus	**267**	265
Retained earnings	**1,185**	854
Foreign exchange adjustment	**(40)**	14
	7,105	6,810
	20,541	19,966

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Retained Earnings

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

See accompanying Notes to the Consolidated Financial Statements.

Notes to Consolidated Financial Statements
(Unaudited)

1. Basis of Presentation

Pursuant to a plan of arrangement, effective May 15, 2003, common shares of TransCanada PipeLines Limited (TCPL or the company) 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 for the year ended December 31, 2003 include the accounts of TCPL and the consolidated accounts of all its subsidiaries.

On December 3, 2003, TCPL increased its ownership interest in Portland Natural Gas Transmission System Partnership (Portland) from 43.4 per cent to 61.7 per cent. Subsequent to the acquisition, Portland was fully consolidated in the company's financial statements, with 38.3 per cent reflected in non-controlling interests.

2. Significant Accounting Policies

The consolidated financial statements of TCPL have been prepared in accordance with Canadian generally accepted accounting principles. The accounting policies applied are consistent with those outlined in TCPL's annual financial statements for the year ended December 31, 2002. These consolidated financial statements reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective periods. These consolidated financial statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the annual financial statements included in TransCanada PipeLines Limited's 2002 Annual Report. Amounts are stated in Canadian dollars unless otherwise indicated. Certain comparative figures have been reclassified to conform with the current period'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. In the opinion of Management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the company's significant accounting policies.

Regulation

In December 2002, the National Energy Board (NEB) approved TCPL's application for the Canadian Mainline to charge interim tolls for transportation service, effective January 1, 2003. In August 2003, subsequent to the NEB's decision on the 2003 Tolls and Tariff Application, it approved interim tolls for the period September 1, 2003 to December 31, 2003. The NEB determined that tolls will remain interim pending a decision from the Federal Court of Appeal on TCPL's Fair Return Review and Variance Application. Any adjustments to the interim tolls will be recorded in accordance with the final NEB decision.

3. Segmented Information

Three months ended December 31 (unaudited - millions of dollars)	Gas Transmission 2003	Gas Transmission 2002	Power 2003	Power 2002	Corporate 2003	Corporate 2002	Total 2003	Total 2002
Revenues	**982**	1,007	**337**	331	**-**	-	**1,319**	1,338
Cost of sales	**-**	-	**(159)**	(161)	**-**	**-**	**(159)**	(161)
Other costs and expenses	**(326)**	(319)	**(106)**	(103)	**(2)**	(1)	**(434)**	(423)
Depreciation	**(202)**	(197)	**(20)**	(20)	**-**	**-**	**(222)**	(217)
Operating income/(loss)	**454**	491	**52**	47	**(2)**	(1)	**504**	537
Financial and preferred equity charges and non-controlling interests	**(193)**	(205)	**(4)**	(4)	**(22)**	(21)	**(219)**	(230)
Financial charges of joint ventures	**(14)**	(23)	**-**	-	**-**	-	**(14)**	(23)
Equity income	**7**	7	**7**	-	**-**	**-**	**14**	7
Interest and other income	**6**	5	**4**	2	**6**	10	**16**	17
Income taxes	**(100)**	(113)	**(15)**	(15)	**7**	-	**(108)**	(128)
Continuing operations	**160**	162	**44**	30	**(11)**	(12)	**193**	180
Discontinued operations							**-**	-
Net Income Applicable to Common Shares							**193**	180

Year ended December 31 (unaudited - millions of dollars)	Gas Transmission 2003	Gas Transmission 2002	Power 2003	Power 2002	Corporate 2003	Corporate 2002	Total 2003	Total 2002
Revenues	**3,956**	3,921	**1,401**	1,293	**-**	-	**5,357**	5,214
Cost of sales	**-**	-	**(692)**	(627)	**-**	-	**(692)**	(627)
Other costs and expenses	**(1,270)**	(1,166)	**(405)**	(371)	**(7)**	(9)	**(1,682)**	(1,546)
Depreciation	**(831)**	(783)	**(82)**	(65)	**(1)**	-	**(914)**	(848)
Operating income/(loss)	**1,855**	1,972	**222**	230	**(8)**	(9)	**2,069**	2,193
Financial and preferred equity charges and non-controlling interests	**(781)**	(821)	**(11)**	(13)	**(89)**	(91)	**(881)**	(925)
Financial charges of joint ventures	**(76)**	(90)	**(1)**	-	**-**	-	**(77)**	(90)
Equity income	**66**	33	**99**	-	**-**	-	**165**	33
Interest and other income	**17**	17	**14**	13	**29**	23	**60**	53
Income taxes	**(459)**	(458)	**(103)**	(84)	**27**	25	**(535)**	(517)
Continuing operations	**622**	653	**220**	146	**(41)**	(52)	**801**	747
Discontinued operations							**50**	-
Net Income Applicable to Common Shares							**851**	747

Total Assets

December 31 (millions of dollars)	2003 (unaudited)	2002
Gas Transmission	**16,972**	16,979
Power	**2,746**	2,391
Corporate	**812**	457
Continuing Operations	**20,530**	19,827
Discontinued Operations	**11**	139
	20,541	19,966

4. Long-Term Debt

December 31 (millions of dollars)	2003 (unaudited)	2002
Alberta System	**2,341**	2,892
Foreign exchange differential recoverable through the tollmaking process	**(16)**	(271)
	2,325	2,621
Canadian Mainline	**4,913**	5,277
Foreign exchange differential recoverable through the tollmaking process	**(60)**	(330)
	4,853	4,947
Other	**2,837**	1,764
	10,015	9,332
Less: current portion of long-term debt	**550**	517
	9,465	8,815

On June 9, 2003, the company issued US$350 million of unsecured 4.00 per cent notes maturing on June 15, 2013. On November 18, 2003, the company issued $450 million of unsecured 5.65 per cent notes maturing on January 15, 2014.

5. Risk Management and Financial Instruments

The following represents the significant changes to the company's risk management and financial instruments since December 31, 2002.

Foreign Investments

At December 31, 2003 and December 31, 2002, 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 company's portfolio of foreign investment derivatives is comprised of contracts for periods up to four years. The fair values shown in the table below for foreign exchange risk are offset by translation gains or losses on the net assets and are recorded in the foreign exchange adjustment account in Shareholders' Equity.

Asset/(Liability)

December 31 (millions of dollars)	2003 (unaudited) Carrying Amount	2003 (unaudited) Fair Value	2002 Carrying Amount	2002 Fair Value
Foreign Exchange				
Cross-currency swaps				
U.S. dollars	**65**	**65**	(8)	(8)

At December 31, 2003, the notional principal amounts of cross-currency swaps were US$250 million (2002 - US$350 million).

Reconciliation of Foreign Exchange Adjustment

December 31 (millions of dollars)	2003 (unaudited)	2002
Balance at beginning of year	**14**	13
Translation (losses)/gains on foreign currency denominated net assets	**(136)**	3
Foreign exchange gains/(losses) on derivatives, and other	**82**	(2)
	(40)	14

Foreign Exchange and Interest Rate Management Activity

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

Asset/(Liability)

December 31 (millions of dollars)	2003 (unaudited) Carrying Amount	2003 (unaudited) Fair Value	2002 Carrying Amount	2002 Fair Value
Foreign Exchange				
Cross-currency swaps	**(26)**	**(26)**	56	56
Interest Rate				
Interest rate swaps				
Canadian dollars	**2**	**15**	4	56
U.S. dollars	**-**	**8**	(1)	4

At December 31, 2003, the notional principal amounts of cross-currency swaps were US$282 million (2002 - US$282 million). Notional principal amounts for interest rate swaps were $964 million (2002 - $874 million) and US$100 million (2002 - US$175 million).

6. Discontinued Operations

The Board of Directors approved plans to dispose of the company's International, Canadian Midstream, and certain other businesses (December Plan) and the Gas Marketing business in December 1999 and July 2001, respectively. The company's disposals under both plans were substantially completed at December 31, 2001.

TCPL's investments in Gasoducto del Pacifico, INNERGY Holdings S.A. and P.T. Paiton Energy Company approved for disposal under the December Plan will be accounted for as part of continuing operations as of December 31, 2003, due to the length of time it has taken the company to dispose of these assets. It is the intention of the company to continue with its plan to dispose of these investments.

The company mitigated certain of its remaining exposures associated with the contingent liabilities related to the divested Gas Marketing operations by acquiring from a subsidiary of Mirant Corporation certain contracts under which it still had exposure in 2003, and simultaneously hedging the market price exposures of these contracts. The company remains contingently liable for certain residual obligations. In 2003, $50 million of the original approximately $100 million after-tax deferred gain was recognized in income. The after-tax deferred gain is included in Deferred Amounts.

At December 31, 2003, TCPL reviewed the provision for loss on discontinued operations and the deferred gain and concluded that the remaining provision was adequate and the deferral of the remaining approximately $50 million of after-tax deferred gain related to the Gas Marketing business was appropriate.

Revenues from discontinued operations for the year ended December 31, 2003 were $2 million (2002 - $36 million). Net income/(loss) from discontinued operations for the year ended December 31, 2003 was $50 million, net of $29 million income taxes (2002 – nil). The provision for loss on discontinued operations at December 31, 2003 was $41 million (2002 - $83 million). The provision for loss on discontinued operations is included in Accounts Payable.

7. Investment in Bruce Power L.P.

On February 14, 2003, the company acquired a 31.6 per cent interest in Bruce Power L.P. (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 TCPL's 31.6 per cent interest in Bruce Power has been allocated as follows.

Purchase Price Allocation
(unaudited)
(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 will be 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 will be 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. The amount allocated to the pension liability will be amortized to income over the 11 year expected average remaining service life of Bruce Power employees, resulting in an annual amortization of $3 million.

8. Commitment

On June 18, 2003, an agreement was reached among the Mackenzie Delta gas producers, the Aboriginal PipeLine Group (APG) and TCPL which governs TCPL's role in the Mackenzie Gas Pipeline Project. The Mackenzie Gas Pipeline Project would result in a natural gas pipeline being constructed from Inuvik, Northwest Territories to the northern border of Alberta, where it would then connect with the Alberta System. Under the agreement, TCPL has agreed to finance the APG for its one-third share of project definition phase costs, which is estimated to be approximately $90 million over three years. In the year ended December 31, 2003, TCPL funded $34 million of this loan which is included in Other Assets. The ability to recover this investment is contingent upon the outcome of the project.

TransCanada welcomes questions from shareholders and potential investors. Please telephone:

Investor Relations, at 1-800-361-6522 (Canada and U.S. Mainland) or direct dial David Moneta/Debbie Stein at (403) 920-7911. The investor fax line is (403) 920-2457. Media Relations: Hejdi Feick/Anita Perry at (403) 920-7859.

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