TRANSCANADA CORPORATION – FIRST QUARTER 2005

Quarterly Report to Shareholders

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TransCanada Announces First Quarter Results, Board Declares Dividend of $0.305 per Share

CALGARY, Alberta – April 29, 2005 – (TSX: TRP) (NYSE: TRP)

First Quarter 2005 Financial Highlights:

(All financial figures are in Canadian dollars unless noted otherwise)

- Net income for first quarter 2005 of $232 million or $0.48 per share.
- Funds generated from operations for first quarter 2005 of $407 million.
- Dividend of $0.305 per common share declared by the Board of Directors.

TransCanada Corporation today announced net income for first quarter 2005 of $232 million or $0.48 per share, compared to $214 million or $0.44 per share for first quarter 2004. The increase of $18 million or $0.04 per share was primarily attributable to the sale of 3.5 million common units of TC PipeLines, LP. The sale generated an after-tax gain of $48 million or $0.10 per share. Partially offsetting this gain was a reduction in income from Power of $35 million or $0.07 per share, which included a $10 million after-tax cost for the restructuring of natural gas supply contracts and the impact of the sale of the Curtis Palmer and ManChief plants in 2004.

Funds generated from operations of $407 million decreased $8 million compared to first quarter 2004.

"Since the beginning of the first quarter, we have continued to add to our portfolio of high quality energy infrastructure to build on our solid growth strategy," said Hal Kvisle, TransCanada's chief executive officer.

"For example, the USGen transaction, which we closed on April 1, will contribute to earnings for the remainder of the year. We are also pleased with the performance of the Gas Transmission Northwest and North Baja Systems which we acquired in November 2004 and contributed net income of $23 million in first quarter 2005.

"Adherence to our strategy, combined with our strong balance sheet, position us to deliver value for shareholders in the future."

During first quarter 2005, TransCanada:

- Announced that it is developing a $200 million natural gas storage facility near Edson, Alberta.
- Proposed a US$1.7 billion oil pipeline project to transport approximately 400,000 barrels per day of heavy crude oil from Alberta to Illinois.
- Reached a settlement with shippers and other interested parties on 2005 tolls on its Canadian Mainline natural gas transmission system. The settlement was approved by the National Energy Board.
- Reached a settlement with shippers and other interested parties for 2005, 2006 and 2007 regarding the annual revenue requirements of the Alberta System. This settlement requires approval by the Alberta Energy and Utilities Board.
- Announced that Cartier Wind Energy (62 per cent owned by TransCanada) had signed long-term electricity supply contracts with Hydro-Québec Distribution for 739.5 megawatts (MW) of wind power projects. The total estimated capital cost of the projects is more than $1.1 billion.
- Announced that wholly-owned subsidiary Foothills Pipe Lines Ltd. had signed a protocol with the Kaska Nation establishing how Kaska traditional knowledge will be integrated into planning, construction and operations of the Alaska Highway Pipeline Project.
- Sold 3.5 million common units of TC PipeLines, LP for $151 million, recording an after-tax gain of $48 million or $0.10 per share.
- Reached agreement with natural gas suppliers for Ocean State Power to terminate existing natural gas supply contracts, replacing them with market price-based supply contracts, resulting in a one-time after-tax cost of $10 million or $0.02 per share.

On April 1, 2005, TransCanada closed the acquisition of hydroelectric generation assets with 567 MW of generating capacity from USGen New England, Inc. for US$505 million in cash. The Town of Rockingham exercised its option to purchase the 49 MW Bellows Falls facility for US$72 million. The Bellows Falls transaction is expected to close by end of second quarter 2005, subject to regulatory approvals and satisfaction of other conditions under the option agreement.

Teleconference

TransCanada will hold a teleconference today at 1:30 p.m. (Mountain) / 3:30 p.m. (Eastern) to discuss the first quarter 2005 financial results and general developments and issues concerning the company. Analysts, members of the media and other interested parties wanting to participate should phone 1-877-211-7911 or 416-405-9310 (Toronto area) at least 10 minutes prior to the start of the teleconference. No passcode is required. A live audio webcast of the teleconference will also be available on TransCanada's website at www.transcanada.com.

The conference will begin with a short address by members of TransCanada's executive management, followed by a question and answer period for investment analysts. A question and answer period for members of the media will immediately follow.

A replay of the teleconference will be available two hours after the conclusion of the call until midnight Eastern time May 6, 2005, by dialing 1-800-408-3053 or 416-695-5800 (Toronto area) and entering pass code 3147965. The webcast will be archived and available for replay.

About TransCanada

TransCanada is a leading North American energy company. TransCanada is focused on natural gas transmission and power services with employees who are expert in these businesses. TransCanada's network of approximately 41,000 kilometres (25,600 miles) of pipeline transports the majority of Western Canada's natural gas production to the fastest growing markets in Canada and the United States. TransCanada owns, controls or is constructing approximately 5,700 megawatts of power generation – an amount of power that can meet the needs of about 5.7 million average households. The Company's common shares trade under the symbol TRP on the Toronto and New York stock exchanges.

First Quarter 2005 Financial Highlights
(unaudited)

Operating Results (millions of dollars)	Three months ended March 31 **2005**	 2004
Revenues	**1,305**	1,266
Net Income	**232**	214
Cash Flows		
Funds generated from operations	**407**	415
Capital expenditures	**108**	101

Common Share Statistics	Three months ended March 31 **2005**	 2004
Net Income Per Share - Basic	**$0.48**	$0.44
Dividends Declared Per Share	**$0.305**	$0.29
Common Shares Outstanding (millions)		
Average for the period	**485.2**	483.4
End of period	**485.6**	483.9

Management's Discussion and Analysis

Management's discussion and analysis (MD&A) dated April 29, 2005 should be read in conjunction with the accompanying unaudited consolidated financial statements of TransCanada Corporation (TransCanada or the company) for the three months ended March 31, 2005 and should also be read in conjunction with the audited consolidated financial statements and MD&A contained in TransCanada's 2004 Annual Report for the year ended December 31, 2004. Additional information relating to TransCanada, including the company's Annual Information Form and continuous disclosure documents, is available on SEDAR at www.sedar.com under TransCanada Corporation. Amounts are stated in Canadian dollars unless otherwise indicated.

Segment Results-at-a-Glance
Three months ended March 31 (unaudited)

(millions of dollars)	**2005**	2004
Gas Transmission	**211**	149
Power	**30**	65
Corporate	**(9)**	-
Net Income	**232**	214
Net Income Per Share - Basic	**$0.48**	$0.44

Results of Operations

Consolidated

TransCanada's net income for first quarter 2005 was $232 million or $0.48 per share compared to $214 million or $0.44 per share for the same period in 2004. The increase of $18 million or $0.04 per share was primarily due to significantly higher net income from the Gas Transmission business resulting mainly from a gain of $48 million after tax or $0.10 per share on the sale of 3.5 million common units of TC PipeLines, LP (PipeLines LP) in first quarter 2005. Excluding this gain, Gas Transmission's net income for first quarter 2005 increased $14 million mainly due to net income of $23 million generated from the Gas Transmission Northwest System and the North Baja System (collectively GTN), which were acquired by TransCanada on November 1, 2004. This increase from GTN was partially offset by lower net income from the Alberta System and the Other Gas Transmission businesses.

A decrease of $35 million in Power's net income for first quarter 2005 compared to first quarter 2004 was primarily due to lower operating and other income from Eastern Operations and Bruce Power L.P. (Bruce Power). Operating and other income from Eastern Operations was lower by $29 million in first quarter 2005 compared to the same period in 2004 primarily as a result of a $10 million after-tax ($16 million pre-tax) cost for the restructuring of natural gas supply contracts by Ocean State Power (OSP) and a $7 million reduction in after-tax income ($12 million pre tax) as a result of the sale of the Curtis Palmer hydroelectric facilities to TransCanada Power, L.P. (Power LP) in April 2004. Bruce Power's equity income was lower mainly due to increased operating expenses.

The increase of $9 million in the Corporate segment's net expenses was mainly as a result of higher financial charges in first quarter 2005 compared to the same period in 2004, and income tax refunds and refund interest received in first quarter 2004, partially offset by certain positive tax adjustments recorded in first quarter 2005.

Funds generated from operations of $407 million for first quarter 2005 decreased $8 million compared to first quarter 2004.

Gas Transmission

The Gas Transmission business generated net income of $211 million for the quarter ended March 31, 2005 compared to $149 million for the same period in 2004.

Gas Transmission Results-at-a-Glance

Three months ended March 31 (unaudited)

(millions of dollars)	**2005**	2004
Wholly-Owned Pipelines		
Canadian Mainline	**63**	64
Alberta System	**37**	40
GTN (1)	**23**	
Foothills System	**5**	6
BC System	**2**	2
	130	112
Other Gas Transmission		
Great Lakes	**14**	17
Iroquois	**4**	8
PipeLines LP	**4**	4
Portland	**6**	6
Ventures LP	**3**	3
TQM	**2**	2
CrossAlta	**5**	1
TransGas	**3**	3
Northern Development	**(1)**	(1)
General, administrative, support costs and other	**(7)**	(6)
	33	37
Gain related to PipeLines LP	**48**	-
	81	37
Net Income	**211**	149

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

Wholly-Owned Pipelines

Canadian Mainline's first quarter 2005 net income of $63 million was $1 million lower than the same quarter in 2004. This decrease is primarily due to a lower rate of return on common equity (ROE), as determined by the National Energy Board (NEB), of 9.46 per cent in 2005 compared to 9.56 per cent in 2004 and a lower average investment base, partially offset by a prior year negative earnings adjustment of $2 million recorded in first quarter 2004. Canadian Mainline's interim tolls and net income in 2005 assume a capital structure comprised of 33 per cent deemed common equity pending the decision on the 2004 Tolls and Tariff Application (Phase II) hearing dealing with capital structure.

The Alberta System's net income of $37 million in first quarter 2005 is $3 million lower than the same quarter in 2004. The decrease is primarily due to a lower investment base in 2005 as well as a lower approved rate of return in 2005. Net income in 2005 reflects a return of 9.50 per cent, as prescribed by the Alberta Energy and Utilities Board (EUB), on deemed common equity of 35 per cent.

GTN, which was acquired by TransCanada in November 2004, generated net income of $23 million in first quarter 2005. The decrease of $1 million in the Foothills System's first quarter 2005 net income compared to the same period in the prior year is primarily due to a lower average investment base in 2005.

Operating Statistics

Three months ended March 31 (unaudited)	Canadian Mainline (1)		Alberta System (2)		Gas Transmission Northwest System (3)	Foothills System		BC System	
	2005	2004	**2005**	2004	**2005**	**2005**	2004	**2005**	2004
Average investment base ($ millions)	**7,910**	8,314	**4,559**	4,762	**n/a** (3)	**693**	722	**220**	231
Delivery volumes (Bcf)									
Total	**767**	723	**1,051**	1,013	**215**	**287**	281	**94**	87
Average per day	**8.5**	7.9	**11.7**	11.1	**2.4**	**3.2**	3.1	**1.1**	1.0

(1) Canadian Mainline deliveries originating at the Alberta border and in Saskatchewan for the three months ended March 31, 2005 were 531 Bcf (2004 - 510 Bcf); average per day was 5.9 Bcf (2004 - 5.6 Bcf).

(2) Field receipt volumes for the Alberta System for the three months ended March 31, 2005 were 965 Bcf (2004 - 950 Bcf); average per day was 10.7 Bcf (2004 - 10.4 Bcf).

(3) TransCanada acquired GTN on November 1, 2004. Both the Gas Transmission Northwest System and the North Baja System are currently operating under fixed rate models approved by the Federal Energy Regulatory Commission and, as a result, the systems' current results are not dependent on average investment base. The North Baja System's total delivery volumes were 19 Bcf; average per day was 0.2 Bcf.

Other Gas Transmission

TransCanada's proportionate share of net income from its Other Gas Transmission businesses was $81 million for the three months ended March 31, 2005 compared to $37 million for the same period in 2004. The first quarter 2005 results include a $48 million after-tax gain on sale of an approximate 20 per cent interest in PipeLines LP. Excluding this gain, net income for the quarter decreased $4 million compared to the same period in 2004. The decrease is mainly due to lower income from Iroquois primarily as a result of a positive tax adjustment recorded in first quarter

2004, and lower income from Great Lakes as a result of lower short-term revenues and higher operating and maintenance costs in first quarter 2005. Other Gas Transmission results were also negatively impacted by a weaker U.S. dollar compared to 2004. These decreases were partially offset by higher earnings from CrossAlta as a result of favourable natural gas storage market conditions. As at March 31, 2005, TransCanada had capitalized $3 million of costs related to its Broadwater liquified natural gas (LNG) project.

On March 23, 2005, TransCanada sold 3.5 million common units of PipeLines LP for net proceeds of approximately $151 million (US$124 million), resulting in an after-tax gain of approximately $48 million (US$40 million). In April 2005, underwriters purchased an additional 74,200 common units, exercising, in part, their option to purchase up to 525,000 additional units on the same terms and conditions as the 3.5 million common units previously sold. PipeLines LP did not receive any proceeds from the sale of the common units. Subsequent to this transaction and the underwriters' exercise of their option, TransCanada continues to own a 13.4 per cent interest in PipeLines LP represented by the general partner interest of 2.0 per cent as well as an 11.4 per cent limited partner interest.

Power

Power Results-at-a-Glance

Three months ended March 31 (unaudited)

(millions of dollars)	**2005**	2004
Western operations	**30**	35
Eastern operations	**5**	34
Bruce Power investment	**30**	48
Power LP investment	**9**	10
General, administrative, support costs and other	**(25)**	(25)
Operating and other income	**49**	102
Financial charges	**(4)**	(2)
Income taxes	**(15)**	(35)
Net Income	**30**	65

Power's net income in first quarter 2005 of $30 million decreased $35 million compared to $65 million in first quarter 2004. The decrease resulted mainly from lower operating and other income in Eastern Operations and Bruce Power.

Eastern Operations' operating and other income was $29 million lower in first quarter 2005 compared to first quarter 2004 due to a $16 million pre-tax ($10 million after-tax) one-time contract restructuring payment from OSP to its natural gas fuel suppliers and a $12 million pre-tax ($7 million after-tax) reduction in income as a result of the sale of the Curtis Palmer hydroelectric facilities to Power LP in April 2004.

Bruce Power's equity income was lower by $18 million in first quarter 2005 compared to first quarter 2004. Effective March 1, 2004, Bruce Power moved from a five-unit operation to a six-unit operation with the commercial startup of Unit 3. Planned maintenance outages on Units 3 and 4 in first quarter 2005 reduced the otherwise potential increase in total plant output as a result of adding a sixth operating unit. Bruce Power experienced higher operating expenses, including depreciation, in first quarter 2005 as a result of adding Unit 3. The $18 million decrease in Bruce

Power's equity income reflects this increase in operating expenses, partially offset by a three per cent increase in total plant output and slightly higher realized prices.

Western Operations

Western Operations Results-at-a-Glance [(1)]
Three months ended March 31 (unaudited)

(millions of dollars)	**2005**	2004
Revenue		
Power sales	**164**	147
Other [(2)]	**11**	7
	175	154
Cost of sales	**(109)**	(90)
Other costs and expenses	**(31)**	(22)
Depreciation	**(5)**	(7)
Operating and other income	**30**	35

(1) ManChief is included until April 30, 2004

(2) Includes Cancarb Thermax, inter-segment eliminations and miscellaneous

Western Operations Sales Volumes [(1)]
Three months ended March 31 (unaudited)

(GWh)	**2005**	2004
Generation vs. Purchased		
Generation	**636**	362
Purchased		
Sundance A & B PPAs	**1,831**	1,812
Other purchases [(2)]	**731**	702
	3,198	2,876
Contracted vs. Spot		
Contracted	**2,685**	2,678
Spot	**513**	198
	3,198	2,876

(1) ManChief is included until April 30, 2004

(2) Includes Sheerness PPA volumes

Western Operations' operating and other income in first quarter 2005 was $30 million compared to $35 million earned in the same period in 2004. The $5 million decrease was mainly due to reduced margins in first quarter 2005 resulting from lower market heat rates on uncontracted volumes of power generated. Lower market heat rates are the result of spot market power prices in Alberta that averaged approximately $3 per megawatt hour (MWh) less, and average natural gas prices that were slightly higher, in first quarter 2005 compared to 2004. A significant portion of plant generation in Western Operations is sold under long-term contract to mitigate price risk. Some output is intentionally not committed under long-term contract to assist in managing Power's overall portfolio of generation. This approach to portfolio management assists in minimizing costs in situations where TransCanada would otherwise have to purchase power in the open market to fulfill its contractual obligations.

Western Operations' revenues increased in first quarter 2005 primarily due to the start-up of the MacKay River facility in mid-2004 and higher revenues from the Sundance power purchase arrangements (PPAs) partially offset by the sale of the ManChief plant to Power LP in April 2004. Generation volumes in first quarter 2005 increased 274 gigawatt hours (GWh) to 636 GWh primarily due to the start-up of the MacKay River facility. Partially offsetting this increase are decreases in volumes associated with unplanned outages at the Bear Creek cogeneration facility in first quarter 2005 and the sale of the ManChief plant. Revenues and cost of sales, related to the Sundance A and B PPAs, increased in 2005 primarily due to higher plant availability and higher power prices under the PPA's. Other costs and expenses were higher in 2005 primarily due to operating costs associated with the MacKay River facility. Depreciation was lower in first quarter 2005 due to the sale of the ManChief plant partially offset by the start-up of the MacKay River facility. In first quarter 2005, approximately 16 per cent of power sales volumes were sold into the spot market compared to seven per cent in 2004. To reduce its exposure to spot market prices on uncontracted volumes, Western Operations, as at March 31, 2005, had fixed price sales contracts to sell forward 7,200 GWh of power for the remainder of 2005 and 7,400 GWh of power for 2006.

Eastern Operations

Eastern Operations Results-at-a-Glance [1]
Three months ended March 31 (unaudited)

(millions of dollars)	**2005**	2004
Revenue		
Power sales	**114**	146
Other	**-**	1
	114	147
Cost of sales	**(51)**	(76)
Other costs and expenses	**(54)**	(30)
Depreciation	**(4)**	(7)
Operating and other income	**5**	34

[1] Curtis Palmer is included until April 30, 2004.

Eastern Operations Sales Volumes [1]
Three months ended March 31 (unaudited)

(GWh)	**2005**	2004
Generation vs. Purchased		
Generation	**444**	377
Purchased	**811**	1,234
	1,255	1,611
Contracted vs. Spot		
Contracted	**1,189**	1,544
Spot	**66**	67
	1,255	1,611

[1] Curtis Palmer is included until April 30, 2004.

Operating and other income in first quarter 2005 from Eastern Operations of $5 million was $29 million lower compared to $34 million earned in the same period in 2004. The decrease was due primarily to a $16 million pre-tax ($10 million after-tax) contract restructuring payment made by OSP to its natural gas fuel suppliers and a $12 million pre-tax ($7 million after-tax) reduction in income as a result of the sale of the Curtis Palmer hydroelectric facilities to Power LP in April 2004. Partially offsetting these decreases was income from the Grandview cogeneration facility in New

Brunswick which was placed in-service in January 2005. In addition, TransCanada mitigated the impact of increased fuel gas costs at OSP in first quarter 2005.

In first quarter 2005, OSP concluded negotiations with its two Canadian natural gas fuel suppliers and terminated the 20-year purchase contracts which were to expire in 2011. Pricing under the terminated purchase contracts had been subject to numerous arbitration proceedings since late 2001. The latest arbitration, in August 2004, had substantially increased OSP's cost of natural gas to a price in excess of market. New contracts were entered into with the existing natural gas suppliers, effective March 2005 and expiring in October 2008, at an agreed upon pricing mechanism based on market, which is not subject to future arbitration proceedings. As part of these arrangements, payments of $16 million were made to the natural gas suppliers. The contract restructuring was a positive event for OSP and management determined, based on current market conditions, there was no asset impairment writedown of OSP required.

Generation volumes in first quarter 2005 increased 67 GWh to 444 GWh compared to 377 GWh in 2004 primarily due to the Grandview cogeneration facility being placed into service on January 1, 2005. Partially offsetting this increase are decreases in volumes associated with the sale of the Curtis Palmer hydroelectric facility to Power LP in April 2004 and reduced generation from the OSP facility. Purchased and contracted sales volumes, and the related revenues and cost of sales, decreased year-over-year primarily due to the expiration of long-term contracts held at the end of 2004. Other costs and expenses increased $24 million primarily as a result of OSP's settlement with its fuel gas suppliers and higher fuel gas costs. Depreciation in first quarter 2005 decreased from first quarter 2004 due to the sale of Curtis Palmer to Power LP in April 2004.

In first quarter 2005, approximately five per cent of power sales volumes were sold into the spot market compared to four per cent in 2004. Eastern Operations is focused on selling the majority of its power under contract to wholesale, commercial and industrial customers while managing a portfolio of power supplies sourced from its own generation, wholesale power purchases and power purchased from Power LP's Castleton plant. To reduce its exposure to spot market prices, Eastern Operations, as at March 31, 2005, had entered into fixed price sales contracts to sell forward 3,600 GWh of power for the remainder of 2005 and 2,800 GWh of power for 2006. Certain contracted volumes are dependent on customer usage levels.

Bruce Power Investment

Bruce Power Results-at-a-Glance
Three months ended March 31 (unaudited)

(millions of dollars)	**2005**	2004
Bruce Power (100 per cent basis)		
Revenues	**418**	399
Operating expenses		
Cash costs (materials, labour, services and fuel)	**(265)**	(219)
Non-cash costs (depreciation and amortization)	**(48)**	(31)
	(313)	(250)
Operating income	**105**	149
Financial charges	**(17)**	(18)
Income before income taxes	**88**	131
TransCanada's interest in Bruce Power income before income taxes	**28**	41
Adjustments	**2**	7
TransCanada's income from Bruce Power before income taxes	**30**	48

Bruce Power's equity income was lower by $18 million in first quarter 2005 compared to first quarter 2004. Effective March 1, 2004, Bruce Power moved from a five-unit operation to a six-unit operation with the commercial startup of Unit 3. Planned maintenance outages on Units 3 and 4 in first quarter 2005 reduced the otherwise potential increase in total plant output as a result of adding a sixth operating unit. Bruce Power experienced higher operating expenses, including depreciation, in first quarter 2005 as a result of adding Unit 3. The $18 million decrease in Bruce Power's equity income reflects this increase in operating expenses, partially offset by a three per cent increase in total plant output and slightly higher realized prices.

TransCanada's share of power output from Bruce Power for first quarter 2005 was 2,598 GWh compared to 2,530 GWh in first quarter 2004. This increase primarily reflects higher output in 2005 as a result of a reduction in unplanned outages in first quarter 2005 compared to first quarter 2004. Approximately 79 reactor days of planned maintenance outages as well as 17 reactor days of minor unplanned outages occurred in first quarter 2005. In first quarter 2004, Bruce Power experienced 49 reactor days of unplanned outages and Unit 3 was unavailable for 60 days due to completion of initial restart activities. The Bruce units ran at an average availability of 81 per cent in first quarter 2005, compared to an 80 per cent average availability during first quarter 2004. A scheduled maintenance outage on Unit 3 began on January 8, 2005 and the unit returned to service on March 8, 2005. Unit 4 began a similar planned maintenance outage on March 12, 2005 that is also expected to last approximately two months.

Overall prices achieved during first quarter 2005 were approximately $50 per MWh, compared to approximately $49 per MWh in first quarter 2004. Approximately 50 per cent of the available output was sold into Ontario's wholesale spot market in first quarter 2005 with the remainder being sold under longer term contracts. On a per unit basis, Bruce operating expenses increased to $38 per MWh in first quarter 2005 from $31 per MWh in first quarter 2004. This increase is due partly to increased outage costs, primarily related to the Units 3 and 4 planned maintenance outages. The increase in operating expenses is also the result of higher staff and lease costs in first quarter 2005, reflecting the move to a six-unit site. In addition, the completion of the Unit 3 restart has resulted in higher depreciation and lower capitalization of labour and other in-house costs in first quarter 2005.

Adjustments to TransCanada's interest in Bruce Power income before income taxes for the three months ended March 31, 2005 were lower than in 2004 primarily due to the cessation of interest capitalization upon the return to service of Unit 3 as well as lower amortization of the purchase price discrepancy related to the fair value of sales contracts in place at the time of acquisition.

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 40 per cent of planned output for the balance of 2005.

On April 15, 2005, Bruce Power experienced a transformer fire outside of the generating facility. As a result, Unit 6 went offline and some biodegradable mineral oil entered into Lake Huron, the clean up of which is close to complete. Unit 6 is expected to return to service in late May and the cost to replace the damaged transformer is not expected to be significant. Primarily as a result of this unplanned outage, overall plant availability for Bruce Power in 2005 is expected to reduce to 83 per cent from the previously reported 85 per cent.

In March 2005, a tentative agreement was reached with an Ontario provincial negotiator for the potential restart of Units 1 and 2 at Bruce Power. Details of the tentative agreement, which have been approved in principle by the Boards of Directors of the major partners of Bruce Power, are now being considered by the Ontario government.

Power LP Investment

Operating and other income of $9 million from Power LP in first quarter 2005 was $1 million lower compared to $10 million in first quarter 2004. The decrease was primarily due to TransCanada's reduced ownership interest in Power LP in 2005 (30.6 per cent compared to 35.6 per cent in first quarter 2004) and the recognition in second quarter 2004 of all previously deferred gains resulting from the removal of the Power LP redemption obligation. Prior to the removal of the redemption obligation, TransCanada was recognizing into income the amortization of these deferred gains over a period through to 2017. Additional earnings from Power LP's second quarter 2004 acquisition of the Curtis Palmer and ManChief facilities partially offset these decreases.

General, Administrative, Support Costs and Other

General, administrative, support costs and other of $25 million in first quarter 2005 were comparable to the same period in 2004.

Power Sales Volumes and Plant Availability

Power Sales Volumes
Three months ended March 31 (unaudited)

(GWh)	2005	2004
Western operations [1]	**3,198**	2,876
Eastern operations [1]	**1,255**	1,611
Bruce Power investment [2]	**2,598**	2,530
Power LP investment [1] [3]	**697**	572
Total	**7,748**	7,589

[1] ManChief and Curtis Palmer volumes are included in Power LP investment effective April 30, 2004.
[2] Sales volumes reflect TransCanada's 31.6 per cent share of Bruce Power output.
[3] TransCanada operates and manages Power LP. The volumes in the table represent 100 percent of Power LP's sales volumes.

Weighted Average Plant Availability [1]

Three months ended March 31 (unaudited)	2005	2004
Western operations [2]	**93%**	99%
Eastern operations [2]	**85%**	98%
Bruce Power investment [3]	**81%**	80%
Power LP investment [2]	**99%**	99%
All plants, excluding Bruce Power investment	**91%**	89%
All plants	**87%**	85%

[1] Plant availability represents the percentage of time in the year that the plant is available to generate power, whether actually running or not and is reduced by planned and unplanned outages.
[2] ManChief and Curtis Palmer are included in Power LP investment effective April 30, 2004.
[3] Unit 3 is included effective March 1, 2004.

In late February 2005, OSP experienced an unplanned outage affecting 50 per cent of the capacity of this facility. This outage is expected to continue into third quarter 2005. This outage is not expected to significantly impact Eastern Operations' operating income.

Corporate

Net expenses were $9 million and nil for the three months ended March 31, 2005 and 2004 respectively. The $9 million increase in net expenses is primarily due to increased interest expense on debt that was issued in 2004 and the receipt of income tax refunds and related interest in first quarter 2004. These negative variances were partially offset by certain positive tax adjustments recorded in 2005.

Liquidity and Capital Resources

Funds Generated from Operations

Funds generated from continuing operations were $407 million for the three months ended March 31, 2005 compared with $415 million for the same period in 2004.

TransCanada expects that its ability to generate adequate amounts of cash in the short term and the long term, when needed, and to maintain financial capacity and flexibility to provide for planned growth remains substantially unchanged since December 31, 2004.

Investing Activities

In the three months ended March 31, 2005, capital expenditures totalled $108 million (2004 - $101 million) and related primarily to construction of new power plants, and maintenance and capacity capital in the Gas Transmission business.

Financing Activities

TransCanada retired $321 million of long-term debt in the three months ended March 31, 2005. In January 2005, the company issued $300 million of medium-term notes bearing interest at 5.10 per cent due in 2017. For the three months ended March 31, 2005, outstanding notes payable increased by $244 million, while cash and short-term investments increased by $438 million.

Dividends

On April 29, 2005, TransCanada's Board of Directors declared a quarterly dividend of $0.305 per share for the quarter ending June 30, 2005 on the outstanding common shares. This is the 166th consecutive quarterly dividend paid by TransCanada and its subsidiary on the common shares. It is payable on July 29, 2005 to shareholders of record at the close of business on June 30, 2005.

Contractual Obligations

Power's commodity purchase obligations as disclosed in the MD&A in TransCanada's 2004 Annual Report were as follows: 2005 - $429 million, 2006 - $255 million; 2007 - $259 million; 2008 - $266 million; 2009 - $277 million and 2010+ - $2,658 million. Primarily as a result of new contracts in first quarter 2005, Power's commodity purchase obligations are currently estimated to be as follows: remainder of 2005 – $583 million; 2006 - $653 million; 2007 - $627 million; 2008 - $550 million; 2009 - $273 million and 2010+ - $2,648 million. There have been no other material changes to TransCanada's contractual obligations, including payments due for the next five years and thereafter, since December 31, 2004. For further information on these contractual obligations, refer to the MD&A in TransCanada's 2004 Annual Report.

Financial and Other Instruments

The following represents the material changes to the company's risk management and financial instruments since December 31, 2004.

Energy Price Risk Management

The company executes power, natural gas and heat rate derivatives in order to manage exposure and risks associated with its overall 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, future 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 at March 31, 2005 and December 31, 2004.

Power

Asset/(Liability) (millions of dollars)		**March 31, 2005** (unaudited)	December 31, 2004
	Accounting Treatment	**Fair Value**	Fair Value
Power - swaps			
(maturing 2005 to 2011)	Hedge	**(35)**	7
(maturing 2005)	Non-hedge	**2**	(2)
Gas - swaps, futures and options			
(maturing 2005 to 2016)	Hedge	**(24)**	(39)
(maturing 2005)	Non-hedge	**(5)**	(2)
Heat rate contracts			
(maturing 2005 to 2006)	Hedge	**-**	(1)

Notional Volumes **March 31, 2005** (unaudited)		Power (GWh)		Gas (Bcf)	
	Accounting Treatment	Purchases	Sales	Purchases	Sales
Power - swaps					
(maturing 2005 to 2011)	Hedge	**1,752**	**7,237**	**-**	**-**
(maturing 2005)	Non-hedge	**330**	**-**	**-**	**-**
Gas - swaps, futures and options					
(maturing 2005 to 2016)	Hedge	**-**	**-**	**78**	**74**
(maturing 2005)	Non-hedge	**-**	**-**	**3**	**6**
Heat rate contracts					
(maturing 2005 to 2006)	Hedge	**-**	**76**	**-**	**-**

Notional Volumes December 31, 2004		Power (GWh)		Gas (Bcf)	
	Accounting Treatment	Purchases	Sales	Purchases	Sales
Power - swaps	Hedge	3,314	7,029	-	-
	Non-hedge	438	-	-	-
Gas - swaps, futures and options	Hedge	-	-	80	84
	Non-hedge	-	-	5	8
Heat rate contracts	Hedge	-	229	2	-

Risk Management

With respect to continuing operations, TransCanada's market, financial and counterparty risks remain substantially unchanged since December 31, 2004. For further information on risks, refer to the MD&A in TransCanada's 2004 Annual Report.

Controls and Procedures

As of the end of the period covered by this quarterly report, TransCanada's management, together with TransCanada'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 TransCanada have concluded that the disclosure controls and procedures are effective.

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

Critical Accounting Policy

TransCanada's critical accounting policy, which remains unchanged since December 31, 2004, is the use of regulatory accounting for its regulated operations. For further information on this critical accounting policy, refer to the MD&A in TransCanada's 2004 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. TransCanada's critical accounting estimate from December 31, 2004 continues to be depreciation expense. For further information on this critical accounting estimate, refer to the MD&A in TransCanada's 2004 Annual Report.

Accounting Change

Financial Instruments – Disclosure and Presentation

Effective January 1, 2005, the company adopted the provisions of the Canadian Institute of Chartered Accountants' amendment to the existing Handbook Section "Financial Instruments – Disclosure and Presentation" which provides guidance for classifying certain financial instruments that embody obligations that may be settled by issuance of the issuer's equity shares as debt when the instrument does not establish an ownership relationship. In accordance with this amendment, TransCanada reclassified the non-controlling interest component of preferred securities as long-term debt.

This accounting change was applied retroactively with restatement of prior periods. The impact of this change on TransCanada's net income in first quarter 2005 and prior periods was nil.

The impact of the accounting change on the company's consolidated balance sheet as at December 31, 2004 is as follows.

(unaudited - millions of dollars)	Increase/(Decrease)
Deferred Amounts [1]	135
Preferred Securities	535
Non-Controlling Interest	
Preferred securities of subsidiary	(670)
Total Liabilities and Shareholders' Equity	-

[1] Regulatory deferral

Outlook

In 2005, the company expects higher net income from the Gas Transmission segment than originally anticipated as a result of the gain related to the sale of PipeLines LP units. Excluding this impact, the company's outlook is relatively unchanged since December 31, 2004. For further information on outlook, refer to the MD&A in TransCanada's 2004 Annual Report.

In 2005, TransCanada will continue to direct its energies towards long-term growth opportunities that will strengthen its financial performance and create long-term value for shareholders. The company's net income and cash flow combined with a strong balance sheet continue to provide the financial flexibility for TransCanada to make disciplined investments in its core businesses of Gas Transmission and Power.

Credit ratings on TransCanada PipeLines Limited'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

Canadian Mainline

In November 2004, the Canadian Association of Petroleum Producers (CAPP) filed an application with the NEB to review and vary its decision on the 2004 Tolls and Tariff Application with respect to three items:

- non-renewable firm transportation (FT-NR) service;
- long-term incentive compensation; and
- regulatory and legal costs.

On February 18, 2005, the NEB decided to review its decision on the toll to be charged for FT-NR, not to review its decision on disputed regulatory and legal costs and, at CAPP's request, deferred its consideration of a review of its decision regarding long-term incentive compensation. On April 13, 2005, CAPP filed notice with the NEB to withdraw the portion of its application dealing with long-term incentive compensation. The NEB heard oral arguments in Calgary, in late April 2005, to consider tolling issues with respect to FT-NR.

In March 2005, TransCanada filed an application for approval of a negotiated settlement with respect to 2005 Canadian Mainline tolls. The settlement established operating, maintenance and administration (OM&A) costs at $169.5 million with variances between actual OM&A costs in 2005 and those agreed to in the settlement accruing to TransCanada. The majority of other cost elements of the 2005 revenue requirement will be treated on a flow through basis. Further, the 2005 ROE is set at 9.46 per cent and the deemed common equity component of the Canadian Mainline's capital structure in 2005 shall be based on the NEB's decision on the Canadian Mainline's cost of capital for 2004, subject to the outcome of any review applications or appeals. On April 7, 2005, the NEB approved TransCanada's application for a negotiated settlement of 2005 Canadian Mainline tolls as filed.

Alberta System

On March 10, 2005, TransCanada reached a settlement with shippers and other interested parties with respect to the annual revenue requirements of the Alberta System for the years 2005, 2006 and 2007. The settlement encompasses all elements of the Alberta System revenue requirement, including OM&A costs, return on equity, depreciation and income and municipal taxes.

In the Alberta System settlement, OM&A costs are fixed at $193 million for 2005, $201 million for 2006, and $207 million for 2007. Any variance between actual OM&A and those agreed to in the settlement in each year will accrue to TransCanada. The majority of other cost elements of the 2005, 2006 and 2007 revenue requirements will be treated on a flow through basis. The return on equity capital will be calculated annually during the term of the settlement using the EUB formula for the purpose of establishing the annual generic rate of return for Alberta utilities on deemed common equity of 35 per cent. For 2005, the ROE under the EUB formula is 9.50 per cent. Depreciation costs will be determined using the depreciation rates and methodology that the company proposed to the EUB in its 2004 General Rate Application (GRA).

On March 21, 2005, TransCanada applied to the EUB for approval of the Alberta System settlement for 2005 to 2007. Upon EUB approval of the settlement, TransCanada intends to withdraw its motion to the Alberta Court of Appeal filed in September 2004 for leave to appeal Phase 1 of the 2004 GRA with respect to the disallowance of applied-for incentive compensation costs.

TransCanada will continue to charge interim tolls for 2005 for transportation service on the Alberta System. The interim tolls, approved by the EUB in December 2004, will remain in effect until final tolls are established through the Phase 2 proceeding of the Alberta System's 2005 GRA. The Phase 2 proceeding will address the allocation of costs among transportation services and rate design. TransCanada filed this application with the EUB on April 15, 2005.

Other Gas Transmission

Northern Development

In March 2005, TransCanada's wholly-owned subsidiary, Foothills Pipe Lines Ltd., signed a Traditional Knowledge Protocol (Protocol) with the Kaska Nation. The Protocol sets out how Kaska Traditional Knowledge will be incorporated into the planning, construction and operations of the Alaska Highway Pipeline Project.

Power

USGen New England, Inc.

On April 1, 2005, TransCanada closed its acquisition of hydroelectric generation assets, with total generating capacity of 567 megawatts (MW), from USGen for US$505 million, subject to specified closing adjustments.

There was an existing agreement in place between the Town of Rockingham (the Town) and USGen which provided the Town with an option to purchase the 49MW Bellows Falls facility for US$72 million. The option was exercised in December 2004 and its rights were assigned to the Vermont Hydroelectric Power Authority (Vermont Hydroelectric). TransCanada has assumed this obligation and will, therefore, sell the Bellows Falls facility to Vermont Hydroelectric for US$72 million. This transaction is expected to close by the end of second quarter 2005 following receipt of regulatory approvals and the satisfaction of certain conditions under the option agreement. When the sale of the Bellows Falls facility is completed, TransCanada will have 12 dams and 36 hydroelectric generating units on two rivers in New England: the 433 MW Connecticut River system in New Hampshire and Vermont and the 84 MW Deerfield River system in Massachusetts and Vermont.

Other

In April 2005, Gas Transmission Northwest Corporation provided notice to the holders of its US$150 million 7.80 per cent Senior Unsecured Debentures (Debentures) that it will exercise its right to redeem all of the outstanding Debentures on June 1, 2005. Holders of the Debentures will be entitled to US$1,069.36 per US$1,000 principal amount. This amount includes US$30.36 representing the redemption premium and US$39.00 representing accrued and unpaid interest to the redemption date.

Share Information

As at March 31, 2005, TransCanada had 485,550,517 issued and outstanding common shares. In addition, there were 10,383,599 outstanding options to purchase common shares, of which 7,956,022 were exercisable as at March 31, 2005.

Selected Quarterly Consolidated Financial Data [(1)]

(unaudited) (millions of dollars except per share amounts)	2005 First	2004 Fourth	2004 Third	2004 Second	2004 First	2003 Fourth	2003 Third	2003 Second
Revenues	**1,305**	1,407	1,247	1,278	1,266	1,319	1,391	1,311
Net Income								
Continuing operations	**232**	185	193	388	214	193	198	202
Discontinued operations	**-**	-	52	-	-	-	50	-
	232	185	245	388	214	193	248	202
Share Statistics								
Net income per share - Basic								
Continuing operations	**$ 0.48**	$ 0.38	$ 0.40	$ 0.80	$ 0.44	$ 0.40	$ 0.41	$ 0.42
Discontinued operations	**-**	-	0.11	-	-	-	0.10	-
	$ 0.48	$ 0.38	$ 0.51	$ 0.80	$ 0.44	$ 0.40	$ 0.51	$ 0.42
Net income per share - Diluted								
Continuing operations	**$ 0.48**	$ 0.38	$ 0.39	$ 0.80	$ 0.44	$ 0.40	$ 0.41	$ 0.42
Discontinued operations	**-**	-	0.11	-	-	-	0.10	-
	$ 0.48	$ 0.38	$ 0.50	$ 0.80	$ 0.44	$ 0.40	$ 0.51	$ 0.42
Dividend declared per common share	**$0.305**	$ 0.29	$ 0.29	$ 0.29	$ 0.29	$ 0.27	$ 0.27	$ 0.27

(1) The selected quarterly consolidated financial data has been prepared in accordance with Canadian GAAP. For a discussion on the factors affecting the comparability of the financial data, including discontinued operations, refer to Note 1 and Note 21 of TransCanada's 2004 audited consolidated financial statements included in TransCanada's 2004 Annual Report.

Factors Impacting Quarterly Financial Information

In the Gas Transmission business, which consists primarily of the company's investments in regulated pipelines, annual revenues and net income from continuing operations (net earnings) fluctuate over the long term based on regulators' decisions and negotiated settlements with shippers. Generally, quarter over quarter revenues and net earnings during any particular fiscal year remain relatively stable with fluctuations arising as a result of adjustments being recorded due to regulatory decisions and negotiated settlements with shippers and due to items outside of the normal course of operations.

In the Power business, which consists primarily of the company's investments in electrical power generation plants, quarter over quarter revenues and net earnings are affected by seasonal weather conditions, customer demand, market prices, planned and unplanned plant outages as well as items outside of the normal course of operations.

Significant items which impacted the last eight quarters' net earnings are as follows.

- Second quarter 2003 net earnings included a $19 million positive after-tax earnings impact of a June 2003 settlement with a former counterparty that had previously defaulted under power forward contracts.
- Third quarter 2003 net earnings included TransCanada's $11 million share of a positive future income tax benefit adjustment recognized by TransGas.

- First quarter 2004 net earnings included approximately $12 million of income tax refunds and related interest.
- Second quarter 2004 net earnings included after-tax gains related to Power LP of $187 million, of which $132 million were previously deferred and were being amortized into income to 2017.
- In third quarter 2004, the EUB's decisions on the GCOC and Phase I of the 2004 GRA resulted in lower earnings for the Alberta System compared to the previous quarters. In addition, third quarter 2004 included a $12 million after-tax adjustment related to the release of previously established restructuring provisions and recognition of $8 million of non-capital loss carry forwards.
- In fourth quarter 2004, TransCanada completed the acquisition of GTN, thereby recording $14 million of net earnings from the November 1, 2004 acquisition date. Power recorded a $16 million pre-tax positive impact of a restructuring transaction related to power purchase contracts between OSP and Boston Edison in Eastern Operations.
- In first quarter 2005, net earnings included a $48 million after-tax gain related to the sale of PipeLines LP units. Power earnings included a $10 million after-tax cost for the restructuring of natural gas supply contracts by OSP. In addition, Bruce Power's equity income was lower than previous quarters due to the impact of planned maintenance outages and the increase in operating costs as a result of moving to a six-unit operation.

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 TransCanada to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the availability and price of energy commodities, regulatory decisions, competitive factors in the pipeline and power industry sectors, and the prevailing economic conditions in North America. For additional information on these and other factors, see the reports filed by TransCanada with Canadian securities regulators and with the United States Securities and Exchange Commission. TransCanada disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Consolidated Income

Three months ended March 31 (unaudited) (millions of dollars except per share amounts)	**2005**	2004
Revenues	**1,305**	1,266
Operating Expenses		
Cost of sales	**160**	166
Other costs and expenses	**424**	368
Depreciation	**250**	232
	834	766
Operating Income	**471**	500
Other Expenses/(Income)		
Financial charges	**207**	207
Financial charges of joint ventures	**16**	14
Equity income	**(41)**	(58)
Interest income and other	**(24)**	(15)
Gain related to PipeLines LP	**(80)**	-
	78	148
Income before Income Taxes and Non-Controlling Interests	**393**	352
Income Taxes		
Current	**161**	103
Future	**(12)**	23
	149	126
Non-Controlling Interests		
Preferred share dividends	**6**	6
Other	**6**	6
	12	12
Net Income	**232**	214
Net Income Per Share - Basic and Diluted	**$0.48**	$0.44
Average Shares Outstanding - Basic (millions)	**485.2**	483.4
Average Shares Outstanding - Diluted (millions)	**487.9**	486.1

See accompanying notes to the consolidated financial statements.

Consolidated Cash Flows

Three months ended March 31 (unaudited) (millions of dollars)	**2005**	2004
Cash Generated From Operations		
Net income	**232**	214
Depreciation	**250**	232
Gain related to PipeLines LP, net of current tax expense (Note 5)	**(30)**	-
Equity income in excess of distributions received	**(34)**	(51)
Pension funding in excess of expense	**(7)**	(12)
Future income taxes	**(12)**	23
Non-controlling interests	**12**	12
Other	**(4)**	(3)
Funds generated from operations	**407**	415
Increase in operating working capital	**(46)**	(42)
Net cash provided by continuing operations	**361**	373
Net cash provided by/(used in) discontinued operations	**4**	(2)
	365	371
Investing Activities		
Capital expenditures	**(108)**	(101)
Disposition of assets	**151**	-
Deferred amounts and other	**(58)**	(47)
Net cash used in investing activities	**(15)**	(148)
Financing Activities		
Dividends	**(146)**	(140)
Notes payable issued/(repaid), net	**244**	(229)
Long-term debt issued	**300**	665
Reduction of long-term debt	**(321)**	(476)
Non-recourse debt of joint ventures issued	**5**	6
Reduction of non-recourse debt of joint ventures	**(7)**	(9)
Common shares issued	**11**	13
Net cash provided by/(used in) financing activities	**86**	(170)
Effect of Foreign Exchange Rate Changes on Cash and Short-Term Investments	**2**	4
Increase in Cash and Short-Term Investments	**438**	57
Cash and Short-Term Investments		
Beginning of period	**188**	338
Cash and Short-Term Investments		
End of period	**626**	395
Supplementary Cash Flow Information		
Income taxes paid	**192**	161
Interest paid	**190**	172

See accompanying notes to the consolidated financial statements.

Consolidated Balance Sheet

(millions of dollars)	**March 31, 2005** (unaudited)	December 31, 2004
ASSETS		
Current Assets		
Cash and short-term investments	**626**	188
Accounts receivable	**539**	627
Inventories	**170**	174
Other	**142**	120
	1,477	1,109
Long-Term Investments	**833**	840
Plant, Property and Equipment	**18,594**	18,704
Other Assets	**1,526**	1,459
	22,430	22,112
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable	**790**	546
Accounts payable	**1,039**	1,135
Accrued interest	**234**	214
Current portion of long-term debt	**773**	766
Current portion of non-recourse debt of joint ventures	**81**	83
	2,917	2,744
Deferred Amounts	**848**	783
Long-Term Debt	**9,703**	9,713
Future Income Taxes	**491**	509
Non-Recourse Debt of Joint Ventures	**779**	779
Preferred Securities	**556**	554
	15,294	15,082
Non-Controlling Interests		
Preferred shares of subsidiary	**389**	389
Other	**81**	76
	470	465
Shareholders' Equity		
Common shares	**4,722**	4,711
Contributed surplus	**271**	270
Retained earnings	**1,739**	1,655
Foreign exchange adjustment	**(66)**	(71)
	6,666	6,565
	22,430	22,112

See accompanying notes to the consolidated financial statements.

Consolidated Retained Earnings

Three months ended March 31 (unaudited) (millions of dollars)	**2005**	2004
Balance at beginning of period	**1,655**	1,185
Net income	**232**	214
Common share dividends	**(148)**	(140)
	1,739	1,259

See accompanying notes to the consolidated financial statements.

Notes to Consolidated Financial Statements
(Unaudited)

1. Significant Accounting Policies

The consolidated financial statements of TransCanada Corporation (TransCanada or the company) have been prepared in accordance with Canadian generally accepted accounting principles (GAAP). The accounting policies applied are consistent with those outlined in TransCanada's annual financial statements for the year ended December 31, 2004 except as stated below. 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's 2004 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.

2. Accounting Change

Financial Instruments – Disclosure and Presentation

Effective January 1, 2005, the company adopted the provisions of the Canadian Institute of Chartered Accountants amendment to the existing Handbook Section "Financial Instruments – Disclosure and Presentation" which provides guidance for classifying certain financial instruments that embody obligations that may be settled by issuance of the issuer's equity shares as debt when the instrument does not establish an ownership relationship. In accordance with this amendment, TransCanada reclassified the non-controlling interest component of preferred securities as long-term debt.

This accounting change was applied retroactively with restatement of prior periods. The impact of this change on TransCanada's net income in first quarter 2005 and prior periods was nil.

The impact of the accounting change on the company's consolidated balance sheet as at December 31, 2004 is as follows.

(unaudited - millions of dollars)	Increase/(Decrease)
Deferred Amounts [1]	135
Preferred Securities	535
Non-Controlling Interest	
Preferred securities of subsidiary	(670)
Total Liabilities and Shareholders' Equity	-

[1] Regulatory deferral

3. Segmented Information

	Gas Transmission		Power		Corporate		Total	
Three months ended March 31 (unaudited - millions of dollars)	**2005**	2004	**2005**	2004	**2005**	2004	**2005**	2004
Revenues	**995**	949	**310**	317	**-**	-	**1,305**	1,266
Cost of sales	**-**	-	**(160)**	(166)	**-**	-	**(160)**	(166)
Other costs and expenses	**(306)**	(285)	**(116)**	(81)	**(2)**	(2)	**(424)**	(368)
Depreciation	**(232)**	(212)	**(18)**	(20)	**-**	-	**(250)**	(232)
Operating income/(loss)	**457**	452	**16**	50	**(2)**	(2)	**471**	500
Financial charges and non-controlling interests	**(187)**	(196)	**(2)**	(2)	**(30)**	(21)	**(219)**	(219)
Financial charges of joint ventures	**(14)**	(14)	**(2)**	-	**-**	-	**(16)**	(14)
Equity income	**11**	10	**30**	48	**-**	-	**41**	58
Interest income and other	**14**	3	**3**	4	**7**	8	**24**	15
Gain related to PipeLines LP	**80**	-	**-**	-	**-**	-	**80**	-
Income taxes	**(150)**	(106)	**(15)**	(35)	**16**	15	**(149)**	(126)
Net Income	**211**	149	**30**	65	**(9)**	-	**232**	214

Total Assets

(millions of dollars)	**March 31, 2005** (unaudited)	December 31, 2004
Gas Transmission	**18,144**	18,410
Power	**2,915**	2,802
Corporate	**1,367**	893
Continuing Operations	**22,426**	22,105
Discontinued Operations	**4**	7
	22,430	22,112

4. Risk Management and Financial Instruments

The following represents the material changes to the company's risk management and financial instruments since December 31, 2004.

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, future 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 at March 31, 2005 and December 31, 2004.

Power

Asset/(Liability) (millions of dollars)		**March 31, 2005** (unaudited)	December 31, 2004
	Accounting Treatment	**Fair Value**	Fair Value
Power - swaps			
(maturing 2005 to 2011)	Hedge	**(35)**	7
(maturing 2005)	Non-hedge	**2**	(2)
Gas - swaps, futures and options			
(maturing 2005 to 2016)	Hedge	**(24)**	(39)
(maturing 2005)	Non-hedge	**(5)**	(2)
Heat rate contracts			
(maturing 2005 to 2006)	Hedge	**-**	(1)

Notional Volumes **March 31, 2005** (unaudited)	Accounting Treatment	Power (GWh) Purchases	Power (GWh) Sales	Gas (Bcf) Purchases	Gas (Bcf) Sales
Power - swaps					
(maturing 2005 to 2011)	Hedge	**1,752**	**7,237**	**-**	**-**
(maturing 2005)	Non-hedge	**330**	**-**	**-**	**-**
Gas - swaps, futures and options					
(maturing 2005 to 2016)	Hedge	**-**	**-**	**78**	**74**
(maturing 2005)	Non-hedge	**-**	**-**	**3**	**6**
Heat rate contracts					
(maturing 2005 to 2006)	Hedge	**-**	**76**	**-**	**-**

Notional Volumes December 31, 2004	Accounting Treatment	Power (GWh) Purchases	Power (GWh) Sales	Gas (Bcf) Purchases	Gas (Bcf) Sales
Power - swaps	Hedge	3,314	7,029	-	-
	Non-hedge	438	-	-	-
Gas - swaps, futures and options	Hedge	-	-	80	84
	Non-hedge	-	-	5	8
Heat rate contracts	Hedge	-	229	2	-

5. Disposition

In March 2005, TransCanada sold 3.5 million common units of TC PipeLines, LP (PipeLines LP) for US$37.04 per unit, resulting in net proceeds to the company of approximately $151 million and an after-tax gain of approximately $48 million. The net gain was recorded in the Gas Transmission segment and the company recorded a $32 million tax charge, including $50 million of current income tax expense, on this transaction. In April 2005, underwriters purchased an additional 74,200 common units, exercising, in part, their option to purchase up to 525,000 additional units on the same terms and conditions as the 3.5 million common units already sold. PipeLines LP did not receive any proceeds from the sale of the common units. Subsequent to this transaction and the underwriter's exercise of their option, TransCanada continues to own a 13.4 per cent interest in PipeLines LP represented by the general partner interest of 2.0 per cent as well as an 11.4 per cent limited partner interest.

6. Employee Future Benefits

The net benefit plan expense for the company's defined benefit pension plans and other post-employment benefit plans for the three months ended March 31 is as follows.

Three months ended March 31	Pension Benefit Plans		Other Benefit Plans	
(unaudited - millions of dollars)	**2005**	2004	**2005**	2004
Current service cost	**7**	7	**-**	-
Interest cost	**16**	14	**1**	1
Expected return on plan assets	**(16)**	(14)	**-**	-
regulated business	**-**	-	**1**	1
Amortization of net actuarial loss	**4**	3	**1**	1
Amortization of past service costs	**1**	1	**-**	-
Net benefit cost recognized	**12**	11	**3**	3

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 at (403) 920-7911. The investor fax line is (403) 920-2457. Media Relations: Hejdi Feick/Kurt Kadatz at (403) 920-7859

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