TRANSCANADA CORP
Form 40-F
March 02, 2006

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U.S. SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 40-F

o **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

ý **ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2005 Commission File Number 1-31690

TRANSCANADA CORPORATION

(Exact Name of Registrant as specified in its charter)

Canada
(Jurisdiction of incorporation or organization)

4922, 4923, 4924, 5172
(Primary Standard Industrial Classification Code Number (if applicable))

Not Applicable
(I.R.S. Employer Identification Number (if applicable))

TransCanada Tower, 450 1 Street S.W.
Calgary, Alberta, Canada, T2P 5H1
(403) 920-2000
(Address and telephone number of Registrant's principal executive offices)

CT Corporation, Suite 2610, 520 Pike Street
Seattle, Washington, 98101; (206) 622-4511; 1-800-456-4511
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered pursuant to section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
Common Shares (including Rights under Shareholder Rights Plan)	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: None

For annual reports, indicate by check mark the information filed with this Form:

ý Annual Information Form ý Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

At December 31, 2005, 487,235,725 common shares were issued and outstanding

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the file number assigned to the Registrant in connection with such Rule.

Yes o No ý

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes ý No o

The documents (or portions thereof) forming part of this Form 40-F are incorporated by reference into the following registration statements under the Securities Act of 1933, as amended:

Form	Registration No.
S-8	33-00958
S-8	333-5916
S-8	333-8470
S-8	333-9130
F-3	33-13564
F-3	333-6132

CONSOLIDATED AUDITED ANNUAL FINANCIAL STATEMENTS AND MANAGEMENT'S DISCUSSION & ANALYSIS

A. Audited Annual Financial Statements

For consolidated audited financial statements, including the report of independent chartered accountants with respect thereto, see pages 75 through 113 of the TransCanada Corporation (TransCanada") 2005 Annual Report to Shareholders included herein. See document 13.4, entitled "U.S. GAAP reconciliation of the 2005 Consolidated Audited Financial Statements", attached to this Form 40-F for a reconciliation of the important differences between Canadian and United States generally accepted accounting principles.

B. Management's Discussion & Analysis

For management's discussion and analysis, see pages 8 through 73 of the TransCanada 2005 Annual Report to Shareholders included herein under the heading "Management's Discussion & Analysis".

For the purposes of this Report, only pages 8 through 73 and 75 through 113 of the TransCanada 2005 Annual Report to Shareholders as referred to above shall be deemed incorporated herein by reference and filed, and the balance of such 2005 Annual Report, except as otherwise specifically incorporated by reference in the TransCanada Annual Information Form, shall be deemed not filed with the Securities and Exchange Commission as part of this Report under the Exchange Act.

UNDERTAKING

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an Annual Report on Form 40-F arises; or transactions in said securities.

DISCLOSURE CONTROLS AND PROCEDURES

Pursuant to the Sarbanes-Oxley Act of 2002, as adopted by the U.S. Securities and Exchange Commission, the Registrant's management evaluates the effectiveness of the design and operation of the company's disclosure controls and procedures (disclosure controls). This evaluation is done under the supervision of, and with the participation of, the President and Chief Executive Officer and the Chief Financial Officer.

As of the end of the period covered by this Annual Report, the Registrant's management evaluated the effectiveness of its disclosure controls. Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer have concluded that the Registrant's disclosure controls are effective in ensuring that material information relating to the Registrant is made known to management on a timely basis, and is included in this Form 40-F.

No change in the Registrant's internal control over financial reporting occurred during the period covered by this annual report that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting.

AUDIT COMMITTEE FINANCIAL EXPERT

The Registrant's board of directors has determined that it has at least one audit committee financial expert serving on its audit committee. Mr. Harry G. Schaefer has been determined to be such audit committee financial expert and is independent, as that term is defined by the New York Stock Exchange's listing standards applicable to the Registrant. The SEC has indicated that the designation of Mr. Schaefer as an audit committee financial expert does not make Mr. Schaefer an "expert" for any purpose, impose any duties, obligations or liability on Mr. Schaefer that are greater than those imposed on members of the audit committee and board of directors who do not carry this designation or affect the duties, obligations or liability of any other member of the audit committee.

CODE OF ETHICS

The Registrant has adopted codes of business ethics for its employees and officers, its principal executive officer, principal financial officer and controller and its directors. The Registrant's codes are available on its website at www.transcanada.com. There has been no waiver of the

codes granted during the 2005 fiscal year.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

The aggregate fees for professional services rendered by KPMG LLP for the TransCanada group of companies for the 2005 and 2004 fiscal years are shown in the table below:

Fees in millions of Canadian dollars	**2005**	**2004**
Audit Fees	**$ 3.15**	$ 2.50
Audit-Related Fees	**0.11**	0.06
Tax Fees	**0.12**	0.06
All Other Fees	**0.14**	0.05
Total	**$ 3.52**	$ 2.67

The nature of each category of fees is described below.

Audit Fees

Audit fees were incurred for professional services rendered by the auditors for the audit of the Registrant's and its subsidiaries' annual financial statements or services provided in connection with statutory and regulatory filings or engagements, the review of interim consolidated financial statements and information contained in various prospectuses and other offering documents.

Audit-Related Fees

Audit-related fees were incurred for the audit of the financial statements of the Registrant's various pension plans.

Tax Fees

Tax fees were incurred for tax compliance and tax advice. These services consisted of: tax compliance including the review of Canadian and US income tax returns and tax items and tax services related to domestic and international taxation including income tax, capital tax and Goods and Services Tax.

All Other Fees

Fees disclosed in the table above under the item "all other fees" were incurred for services other than the audit fees, audit-related fees and tax fees described above. These services consisted of advice with regard to compliance with the Sarbanes-Oxley Act of 2002.

Pre-Approval Policies and Procedures

TransCanada's Audit Committee has adopted a pre-approval policy with respect to permitted non-audit services. Under the policy, the Audit Committee has granted pre-approval for specified non-audit services. For engagements of $25,000 CDN or less which are not within the annual pre-approved limit approval by the Audit Committee is not required, and for engagements between $25,000 CDN and $100,000 CDN, approval of the Audit Committee chair is required, and in both instances the Audit Committee is to be informed of the engagement at the next scheduled Audit Committee meeting. For all engagements of $100,000 CDN or more, pre-approval of the Audit Committee is required. In all cases, regardless of dollar amount involved, where there is a potential for conflict of interest involving the external auditor on an engagement, the Audit Committee chair must pre-approve the assignment.

To date, TransCanada has not approved any non-audit services on the basis of the de-minimis exemptions. All non-audit services have been pre-approved by the Audit Committee in accordance with the pre-approval policy described above.

OFF-BALANCE SHEET ARRANGEMENTS

The Registrant has no off-balance sheet arrangements, as defined in this Form, other than the guarantees described in Note 22 of the Notes to the Consolidated Financial Statements and document 13.4, entitled "U.S. GAAP Reconciliation of the 2005 Consolidated Audited Financial Statements", attached to this Form 40-F. The disclosure relating to guarantees in Note 22 to the Consolidated Financial Statements is incorporated herein by reference.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

(millions of Canadian dollars)

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-Term Debt Obligations	10,757	427	1,191	1,509	7,630
Capital (Finance) Lease Obligations	254	7	17	24	206
Interest Payments on Long-Term Debt	11,640	876	1,653	1,435	7,676
Operating Lease Obligations	834	34	82	85	633
Purchase Obligations[(1)]	11,421	2,197	2,905	1,359	4,960
Other Long-Term Liabilities Reflected on the Registrant's Balance Sheet under the GAAP of the primary financial statements					
Total	34,906	3,541	5,848	4,412	21,105

(1) The amounts in this table exclude the expected funding contributions of approximately $95 million and $7 million, in 2006, to the Registrant's pension plans and other benefit plans, respectively. The amounts in this table also exclude the Registrant's proportionate share of expected funding contributions to be made by joint ventures of approximately $27 million and $2 million, in 2006, to the registered pension plans and other benefit plans, respectively.

For further information on purchase obligations see "Management's Discussion and Analysis Contractual Obligations Purchase Obligations", which is incorporated herein by reference.

IDENTIFICATION OF THE AUDIT COMMITTEE

The Registrant has a separately-designated standing Audit Committee. The members of the Audit Committee are:

Chair:	H.G. Schaefer
Members:	D.D. Baldwin
	K.E. Benson
	P. Gauthier
	P.L. Joskow

FORWARD-LOOKING INFORMATION

This document, documents incorporated herein by reference, and other reports and filings made with the securities regulatory authorities include forward-looking statements. All forward looking statements are based on TransCanada's current beliefs as well as assumptions based on information available at the time the assumption was made. Forward-looking statements relate to, among other things, anticipated financial performance, business prospects, strategies, regulatory developments, new services, market forces, commitments and technological developments. By its nature, such forward-looking information is subject to various risks and uncertainties, including those discussed herein in TransCanada's Annual Information Form filed as document 13.1 hereto and in TransCanada's Management's Discussion and Analysis filed as document 13.2 hereto, which could cause TransCanada's actual results and experience to differ materially from the anticipated results or other

expectations expressed. Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date hereof or otherwise, and TransCanada undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this Annual Report to be signed on its behalf by the undersigned, thereto duly authorized, in the City of Calgary, Province of Alberta, Canada.

TRANSCANADA CORPORATION

Date: March 2, 2006

Per: /s/ RUSSELL K. GIRLING

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

DOCUMENTS FILED AS PART OF THIS REPORT

13.1	TransCanada Corporation Annual Information Form for the year ended December 31, 2005.
13.2	Management's Discussion and Analysis (included on pages 8 through 73 of the TransCanada 2005 Annual Report to Shareholders).
13.3	2005 Consolidated Audited Financial Statements (included on pages 75 through 113 of the TransCanada 2005 Annual Report to Shareholders).
13.4	Reconciliation to United States GAAP.
99.1	Comments by Auditors for U.S. Readers on Canada-U.S. Reporting Difference.

EXHIBITS

23.1	Consent of KPMG LLP Chartered Accountants.
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer regarding Periodic Report containing Financial Statements.
32.2	Certification of Chief Financial Officer regarding Periodic Report containing Financial Statements.

TRANSCANADA CORPORATION

ANNUAL INFORMATION FORM

February 27, 2006

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PRESENTATION OF INFORMATION

Unless otherwise noted, the information contained in this Annual Information Form ("*AIF*") is given at or for the year ended, December 31, 2005 ("*Year End*"). Amounts are expressed in Canadian dollars unless otherwise indicated. Financial information is presented in accordance with Canadian generally accepted accounting principles.

This AIF provides material information about the business and operations of TransCanada Corporation ("*TransCanada*"). TransCanada's Management's Discussion and Analysis dated February 27, 2006 ("*MD&A*") and TransCanada's Audited Consolidated Financial Statements are incorporated by reference into this AIF and can be found in TransCanada's Annual Report to Shareholders for the year ended December 31, 2005 ("*Annual Report*") which is available on TransCanada's profile on SEDAR at www.sedar.com.

Unless the context indicates otherwise, a reference in this AIF to "TransCanada" includes the subsidiaries of TransCanada through which its various business operations are conducted. In particular, "TransCanada" includes references to TransCanada PipeLines Limited ("*TCPL*"). Where TransCanada is referred to with respect to actions that occurred prior to its 2003 plan of arrangement with TCPL, which is described below under the heading "TransCanada Corporation Corporate Structure", these actions were taken by TCPL or its subsidiaries. The term "subsidiary", when referred to in this AIF, with reference to TransCanada means direct and indirect wholly-owned subsidiaries of, and entities controlled by, TransCanada or TCPL, as applicable.

Trends impacting TransCanada's gas transmission and power businesses are discussed in the MD&A under the headings "Gas Transmission" (under the subheadings "Opportunities and Developments", "Regulatory Developments" and "Business Risks") and "Power" (under the subheadings "Opportunities and Developments" and "Business Risks").

FORWARD-LOOKING INFORMATION

This AIF, the documents incorporated by reference into this AIF, and other reports and filings made with the securities regulatory authorities include forward-looking statements. All forward-looking statements are based on TransCanada's beliefs and assumptions based on information available at the time the assumption was made. Forward-looking statements relate to, among other things, anticipated financial performance, business prospects, strategies, regulatory developments, new services, market forces, commitments and technological developments. Much of this information also appears in the MD&A. By its nature, such forward-looking information is subject to various risks and uncertainties, including those material risks discussed in this AIF under "Risk Factors" and in the MD&A under "Gas Transmission Business Risks" and "Power Business Risks", which could cause TransCanada's actual results and experience to differ materially from the anticipated results or other expectations expressed. The material assumptions in making these forward-looking statements are disclosed in the MD&A under the headings "Overview and Strategic Priorities", "Gas Transmission Opportunities and Developments", "Gas Transmission Outlook", "Power Opportunities and Developments" and "Power Outlook". Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this AIF or otherwise, and TransCanada undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise.

REFERENCE INFORMATION

For the reference information noted below, please refer to Schedule "A".

Exchange Rate of the Canadian Dollar

Metric Conversion Table

TRANSCANADA CORPORATION

Corporate Structure

TransCanada's head office and registered office are located at 450 - 1st Street S.W., Calgary, Alberta, T2P 5H1.

TransCanada was incorporated pursuant to the provisions of the *Canada Business Corporation Act* on February 25, 2003 in connection with a plan of arrangement which established TransCanada as the parent company of TCPL. The arrangement was approved by TCPL common shareholders on April 25, 2003 and, following court approval and the filing of Articles of Arrangement, the arrangement became effective May 15, 2003. Pursuant to the arrangement, the common shareholders of TCPL exchanged each of their TCPL common shares for one common share of TransCanada. The debt securities and preferred shares of TCPL remained obligations and securities of TCPL. TCPL continues to hold the assets it held prior to the arrangement and continues to carry on business as the principal operating subsidiary of the TransCanada group of entities. TransCanada does not hold any assets directly other than the common shares of TCPL.

TransCanada is a Canadian public company. Significant dates and events are set forth below.

Date	Event
February 25, 2003	TransCanada incorporated under *Canada Business Corporations Act*
May 15, 2003	Certificate of Arrangement issued

The significant dates and events relating to TCPL are set out in TCPL's Annual Information Form for the year ended December 31, 2005, dated February 27, 2006.

TransCanada does not directly employ any employees or contractors. At Year End, TransCanada's principal operating subsidiary, TCPL, had approximately 2,350 employees, substantially all of whom were employed in Canada and the United States.

Significant Subsidiaries

TransCanada's significant subsidiaries[(1)] at Year End and the jurisdiction under which each subsidiary was incorporated are noted below. TransCanada owns, directly or indirectly, 100 per cent of the voting shares of each of these subsidiaries.

(1) Excludes certain of TransCanada's subsidiaries where:

- the total assets of each excluded subsidiary do not exceed ten per cent of the consolidated assets of TransCanada at Year End;
- the sales and operating revenues of each excluded subsidiary do not exceed ten per cent of the consolidated sales and operating revenues of TransCanada for the year ended, December 31, 2005;
- the aggregate assets of all the excluded subsidiaries do not exceed 20 per cent of the consolidated assets of TransCanada at Year End; and
- the aggregate sales and operating revenues of all the excluded subsidiaries do not exceed 20 per cent of the consolidated sales and operating revenues of TransCanada for the year ended, December 31, 2005.

GENERAL DEVELOPMENT OF THE BUSINESS

The general development of TransCanada's business during the last three financial years, and the significant acquisitions, events or conditions which have had an influence on that development, are described below.

Developments in Gas Transmission Business

TransCanada's focus has been to sustain, grow and optimize its natural gas transmission business. Summarized below are significant developments that have occurred in TransCanada's natural gas transmission business over the last three years.

2005

In 2005, some of the significant natural gas transmission developments that occurred involved the sale of common units of TC PipeLines, LP, regulatory matters including the National Energy Board's ("*NEB*") decision on the Canadian Mainline 2004 Tolls and Tariff Application (Phase II) and a settlement relating to the Alberta System, on-going construction of a natural gas storage facility located near Edson, Alberta, continued funding of the Mackenzie Valley

Aboriginal Pipeline Limited Partnership (known as "*Aboriginal Pipeline Group*" or "*APG*") for its participation in the Mackenzie Gas Pipeline Project, continued discussions relating to the proposed Alaska Highway Pipeline Project, launching of the Keystone crude oil pipeline project and the announcement in January 2006 that firm, long-term contracts were secured for the project, continued work toward gaining regulatory approval for its two liquified natural gas ("*LNG*") projects: Cacouna in Québec and the Broadwater Energy project, offshore of New York State in Long Island Sound, acquisition of an additional interest in the Iroquois Gas Transmission System L.P. ("*Iroquois System*") and the commencement of construction of the Tamazunchale Pipeline in east-central Mexico. Further information about each of these developments can be found in the MD&A under the heading "TransCanada's Strategy Gas Transmission" and "Gas Transmission Opportunities and Developments".

2004

In September 2004, TransCanada and Petro-Canada signed a memorandum of understanding for the development of the Cacouna Energy LNG facility in Cacouna, Québec, approximately 15 kilometres northeast of Rivière-du-Loup. The proposed facility will be capable of receiving, storing and regasifying imported LNG with an average annual send out capacity of approximately 500 million cubic feet per day of natural gas. TransCanada and Petro-Canada will share equally the construction costs of the facility, which are estimated to be $660 million. TransCanada will operate the facility while Petro-Canada will contract for the facility's entire regasification capacity and supply the LNG. The proposed facility requires regulatory and other approvals from federal, provincial and municipal governments and regulators and the regulatory approval process is anticipated to take approximately two years to complete. In September 2005, the village of Cacouna, Québec voted 57.2 per cent in favour of an LNG terminal to be built in the area. Québec's Ministry of Environment commenced its 45 day public consultation period on February 22, 2006 regarding its next phase for this project. TransCanada continues to work towards gaining regulatory approval and provided the necessary approvals are obtained, the facility is anticipated to be in service towards the end of this decade.

In November 2004, TransCanada acquired the Gas Transmission Northwest System and the North Baja System from National Energy & Gas Transmission, Inc. ("*NEGT*") for US$1.7 billion, including approximately US$0.5 billion of assumed debt, subject to typical closing adjustments. The 2,174 kilometre Gas Transmission Northwest System, formerly known as Pacific Gas Transmission, extends from a connection point on TransCanada's BC System and Foothills System near Kingsgate, British Columbia on the B.C./Idaho border to a point near Malin, Oregon on the Oregon/California border. The natural gas transported on this system originates primarily in Canada and is supplied to markets in the Pacific Northwest, California and Nevada. The 129 kilometre North Baja System extends from a point near Ehrenberg, Arizona to a point near Ogilby, California on the California/Mexico border. The natural gas transported on the North Baja System comes primarily from supplies in the southwestern U.S. for markets in northern Baja California, Mexico.

In November 2004, TransCanada and Shell US Gas & Power LLC ("*Shell*") announced plans to jointly develop an offshore LNG regasification terminal, Broadwater Energy, in the New York State waters of Long Island Sound. The proposed floating storage and regasification unit will be capable of receiving, storing and regasifying imported LNG with an average send out capacity of approximately one billion cubic feet ("*Bcf*") per day of natural gas. TransCanada and Shell will build and install a floating storage and regasification unit at a location approximately 15 kilometres off the Long Island coast and 18 kilometres off the Connecticut coast. TransCanada will own 50 per cent of Broadwater Energy LLC, which will own and operate the facility, while Shell will contract for the facility's entire regasification capacity and supply the LNG. The estimated cost of construction is approximately US$700 million to US$1 billion. The proposed Broadwater Energy LNG facility requires regulatory approval from federal and state governments before construction can begin and the regulatory approval process is anticipated to take up to three years to complete. Provided the necessary approvals are granted and commercial commitments obtained, the facility could be in service in late 2010 or early 2011. TransCanada, on behalf of the Broadwater Energy project, filed a formal application with the U.S. Federal Energy Regulatory Commission ("*FERC*") in January 2006, for federal approval to construct and operate Broadwater.

2003

In August 2003, TransCanada acquired the remaining interests in Foothills Pipe Lines Ltd. ("*Foothills*") that it did not previously own. The Foothills System, which is owned by Foothills, extends 1,040 kilometres and has two legs: one which originates south of Caroline, Alberta and runs along the foothills of the Rocky Mountains through the Crowsnest Pass to Kingsgate, B.C. where it connects to the Gas Transmission Northwest System; and the other which originates south of Caroline, Alberta and runs southeast across Alberta and Saskatchewan to the Canada-U.S. border near Monchy, Saskatchewan where it interconnects with Northern Border Pipeline Company ("*Northern Border Pipeline*"). The Foothills System carries over 30 per cent of all Canadian natural gas exports to the U.S.

TransCanada, through Foothills, holds certificates for both the Alaskan and Canadian segments of the Alaska Highway Pipeline Project and also holds significant right-of-way assets for the project in both Canada and Alaska.

In June 2003, TransCanada, the Mackenzie Delta Producers Group ("*Mackenzie Producers*") and the APG reached a funding and participation agreement. TransCanada agreed to finance the APG's share of project development costs in exchange for certain rights in the Mackenzie Gas Pipeline Project, including a right to an ownership interest in the pipeline at the decision to construct, preferential rights of first refusal and preferential expansion rights and the right of connection of the Mackenzie Delta natural gas flow into the Alberta System. For current information about the Mackenzie Gas Pipeline Project, please refer to the MD&A under the heading "Gas Transmission Opportunities and Development Mackenzie Gas Pipeline Project".

Through acquisitions that took place in September and December 2003, TransCanada increased its ownership interest in Portland Natural Gas Transmission System Partnership ("*Portland*") in the northeastern U.S. from 33.3 per cent to 61.7 per cent.

Developments in Power Business

In the past three years, TransCanada has grown its power business and, in particular, has increased its generation capacity from facilities it owns, operates and/or controls, including those under construction or in development, from 4,667 megawatts ("*MW*") in 2003 to 6,736 MW at Year End. Summarized below are significant developments that have occurred in TransCanada's power business over the last three years.

2005

The significant power developments that occurred in 2005 included the advancement of the 739.5 MW Cartier Wind Energy project ("*Cartier Wind Energy*"), the sale of TransCanada's approximate 11 per cent interest in P.T. Paiton Energy Company ("*Paiton Energy*") to subsidiaries of The Tokyo Electric Power Company resulting in gross proceeds of US$103 million ($122 million), the acquisition of the 756 MW Sheerness Power Purchase Arrangement for $585 million, the restructuring of Bruce Power L.P. ("*Bruce B*") and the execution of agreements by Bruce Power A L.P. ("*Bruce A*") with the Ontario Power Authority to restart and refurbish units at Bruce A, the acquisition of power generation assets from USGen New England, Inc. ("*USGen*") for US$505 million, the sale of all of TransCanada's interests in TransCanada Power, L.P. ("*Power LP*") to EPCOR Utilities Inc. for net proceeds of $523 million in August 2005 and OSP's successful restructuring of its long-term natural gas fuel supply contracts with its supplier.

Further information about each of these power developments can be found in the MD&A under the heading "TransCanada's Strategy Power". Further information can be found in the MD&A about Bruce A and Bruce B under the heading "Power Financial Analysis Bruce Power", about the sale of Paiton Energy under "Power Highlights Net Earnings", "Power Power Results-at-a-Glance", "Discontinued Operations" and elsewhere, and about the Power LP under the heading "Power Financial Analysis Power LP Investment".

2004

TransCanada received approval from the Québec government in April 2004, to develop the 550 MW natural gas-fired Bécancour cogeneration plant which is located at an industrial park near Trois-Rivières, Québec ("*Bécancour Plant*") and which will supply its entire power output to Hydro-Québec Distribution under a 20 year power purchase contract. The

Bécancour Plant will also supply steam to two other companies located within the same industrial park. Construction of the 550 MW Bécancour Plant began in the third quarter of 2004. The cost of the Bécancour Plant is estimated to be $550 million, and the plant is expected to be in service in late 2006.

In April 2004, TransCanada sold its ManChief and Curtis Palmer power plants to Power LP for approximately US$402.6 million, excluding closing adjustments. The acquisition was partially financed by Power LP through a public offering of subscription receipts which were subsequently converted into limited partnership units. TransCanada did not take up its full pro rata share of the units and as a result, its interest in Power LP was reduced from 35.6 per cent to 30.6 per cent.

Cartier Wind Energy, of which 62 per cent is owned by TransCanada, was awarded six wind energy projects by Hydro-Québec Distribution in October 2004, representing a total of 739.5 MW in the Gaspé region of Québec. The six projects are distributed throughout the Gaspésie-Iles-de-la-Madeleine region and the Regional County Municipality of Matane and are expected to cost a total of more than $1.1 billion to develop and construct. Construction of the first two of six wind farm projects will commence in early 2006 and the first of the two projects is expected to be in service in late 2006. The entire output will be supplied to Hydro-Québec Distribution under a 20-year power purchase contract.

Construction of the 165 MW MacKay River power plant located in Alberta was completed in 2003 and the plant was put into commercial service in 2004.

Construction of the 90 MW Grandview natural gas-fired cogeneration power plant on the site of the Irving Oil refinery in Saint John, New Brunswick ("*Grandview Plant*") was completed by the end of 2004 and was commissioned in January 2005. Under a 20 year tolling arrangement, a subsidiary of Irving Oil Limited will provide fuel to the Grandview Plant and has contracted for 100 per cent of the Grandview Plant's heat and electricity output.

2003

In February 2003, TransCanada, as part of a consortium, acquired a 31.6 per cent interest in Bruce B and a 33.3 per cent interest in Bruce Power Inc., the general partner of Bruce B. Bruce B leases its generation facilities from Ontario Power Generation Inc. ("*OPG*"). The facilities consist of eight nuclear reactors, five of which were operational at the end of 2003, with a capacity of 3,950 MW. An additional reactor with capacity of 750 MW commenced commercial operations in March 2004.

The members of the purchasing consortium of Bruce B severally guaranteed, on a pro-rata basis, certain contingent financial obligations of Bruce B related to operator licenses, the OPG lease agreement, power sales agreements and contractor services. Bruce B continues to be operated by experienced nuclear power plant operators. Spent fuel and decommissioning liabilities remain with OPG under the terms of the lease.

Recent Developments

On February 9, 2006, TransCanada announced the filing by its subsidiary, North Baja Pipeline LLC, of an application with the FERC for a certificate for a two-phase expansion of its existing natural gas pipeline in southern California and the construction of a new pipeline lateral in California's Imperial Valley.

TransCanada announced on February 15, 2006, that it will sell its 17.5 per cent general partner interest in Northern Border Partners, L.P. to a subsidiary of ONEOK, Inc. for a net payment of US$30 million subject to certain closing adjustments. In addition, TransCanada will become the operator of Northern Border Pipeline ("*NBPL*") in early 2007. The transaction is expected to close in the second quarter of 2006 and is part of a series of transactions that will also result in TC PipeLines, LP, an affiliate of TransCanada, acquiring an additional 20 per cent interest in NBPL from Northern Border Partners, L.P., bringing its total general partnership interest in NBPL to 50 per cent.

BUSINESS OF TRANSCANADA

TransCanada is a leading North American energy infrastructure company focused on natural gas transmission and power generation. At Year End, the gas transmission business accounted for approximately 68 per cent of revenues and 76 per cent of TransCanada's total assets and the power business accounted for approximately 32 per cent of revenues and 20 per cent of TransCanada's total assets. The following is a description of each of TransCanada's two main areas of operation.

The following table shows TransCanada's revenues from operations by segment, classified geographically, for the years ended December 31, 2005 and 2004.

Revenues From Operations *(millions of dollars)*	**2005**	**2004**
Gas Transmission		
Canada Domestic Deliveries	**2,451**	2,441
Canada Export Deliveries[1]	**1,159**	1,259
United States	**553**	229
	4,163	3,929
Power[2]		
Canada Domestic Deliveries	**1,048**	773
Canada Export Deliveries[1]	**1**	2
United States	**912**	793
	1,961	1,568
Total Revenues[3]	**6,124**	5,497

(1) Export deliveries include gas transmission revenues attributable to deliveries to U.S. pipelines and power deliveries to U.S. markets.

(2) Revenues include sales of natural gas.

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

Gas Transmission Business

TransCanada, through subsidiaries, has substantial Canadian and U.S. natural gas pipeline and related holdings, including:

Canada

a natural gas transmission system running from the Alberta border east to delivery points in eastern Canada and at various U.S. border points ("*Canadian Mainline*");

a natural gas transmission system throughout the province of Alberta ("*Alberta System*");

a natural gas transmission system in southeastern B.C., southern Alberta and southwestern Saskatchewan ("*Foothills System*");

a natural gas transmission system in southeastern B.C. ("*BC System*");

a 121 km natural gas transmission pipeline and related facilities which supplies natural gas to the oil sands region of northern Alberta and a 27 km natural gas pipeline which supplies natural gas to a petrochemical complex at Joffre, Alberta;

a 50 per cent interest in Trans Québec & Maritimes Pipeline Inc. ("*TQM*") which operates a natural gas transmission system in southeastern Québec ("*TQM System*"); and

a 60 per cent interest in CrossAlta Gas Storage Services Ltd., a long-term natural gas storage contract and the Edson gas storage facility which is currently under construction.

United States

the Gas Transmission Northwest System, a natural gas transmission system running from northwestern Idaho, through Washington and Oregon to the California border;

the North Baja System, a natural gas transmission system which extends from southwestern Arizona to a point near Ogilby, California on the California/Mexico border;

a 50 per cent interest in the Great Lakes Gas Transmission system ("*Great Lakes System*") which is located in the north central U.S., roughly parallel to the Canada-U.S. Border;

a 44.5 per cent interest in the Iroquois System which runs southwards down through the eastern part of the State of New York terminating at points in Long Island and New York City;

a 61.7 per cent interest in the Portland system which runs through Maine and New Hampshire into Massachusetts;

a 4 per cent effective ownership interest, held through TC PipeLines, LP, in the NBPL system which is located in the upper midwestern portion of the U.S.; and

a 7.6 per cent effective ownership interest in the Tuscarora Gas Transmission Company ("*Tuscarora*") system which runs from Oregon eastwards to the upper portion of Nevada. One per cent of this interest is held directly through a subsidiary of TransCanada and the remainder is held through TransCanada's interest in TC PipeLines, LP.

TransCanada holds a 13.4 per cent interest in TC PipeLines, LP, a publicly held limited partnership of which a subsidiary of TransCanada acts as the general partner. The remaining interest of TC PipeLines, LP is widely held by the public. At Year End, TC PipeLines, LP held a 30 per cent interest in NBPL and a 49 per cent interest in Tuscarora.

TransCanada also has the following natural gas pipeline and related holdings in Central and South America which are held through subsidiaries:

a 46.5 per cent interest in the TransGas system which runs from Mariquita in central Colombia to Cali in southwest Colombia;

a 30 per cent interest in the Gas Pacifico pipeline which extends from Loma de la Lata, Argentina to Concepción, Chile;

a 30 per cent interest in INNERGY Holdings S.A. which is an industrial natural gas marketing and distribution company based in Concepción, Chile; and

the Tamazunchale natural gas pipeline, which is under construction and expected to be in service in December 2006, and extends from the Pemex Gas facilities near Naranjos, Veracruz, Mexico to an electricity generation station near Tamazunchale, San Luis Potosi, Mexico.

Further information about TransCanada's pipeline holdings, developments and opportunities relating to gas transmission and significant regulatory developments which relate to gas transmission can be found in the MD&A under the headings "Gas Transmission", "Gas Transmission Opportunities and Developments" and "Gas Transmission Regulatory Developments".

In addition, information about the Mackenzie Gas Pipeline Project and the Alaska Highway Pipeline Project can be found in the MD&A under the headings "Gas Transmission Opportunities and Developments Mackenzie Gas Pipeline Project" and "Gas Transmission Opportunities and Developments Alaska Highway Pipeline Project", respectively and about TransCanada's activities relating to LNG under the heading "Gas Transmission Opportunities and Developments LNG".

Regulation

Canadian Mainline

Under the terms of the *National Energy Board Act* (Canada), the Canadian Mainline is regulated by the NEB. The NEB sets tolls which provide TransCanada the opportunity to recover projected costs of transporting natural gas, including

the return on the Canadian Mainline's average investment base. In addition, new facilities are approved by the NEB before construction begins and the NEB regulates the operation of the Canadian Mainline. Net earnings of the Canadian Mainline are affected by changes in investment base, the return on equity, the level of deemed common equity and the potential for incentive earnings.

Alberta System

The Alberta System is regulated by the Alberta Energy and Utilities Board ("*EUB*") primarily under the provisions of the *Gas Utilities Act (Alberta)* ("*GUA*") and the *Pipeline Act (Alberta)*. Under the GUA, its rates, tolls and other charges, and terms and conditions of service are subject to approval by the EUB. Under the provisions of the *Pipeline Act*, the EUB oversees various matters including the economic, orderly and efficient development of the pipeline, the operation and abandonment of the pipeline and certain related pollution and environmental conservation issues. In addition to requirements under the *Pipeline Act*, the construction and operation of natural gas pipelines in Alberta are subject to certain provisions of other provincial legislation such as the *Environmental Protection and Enhancement Act* (Alberta).

Power

The Power segment of TransCanada's business includes the acquisition, development, construction, ownership and operation of electrical power generation plants, the purchase and marketing of electricity and the provision of electricity account services to energy and industrial customers.

The electrical power generation plants and power supply that TransCanada owns, operates and/or controls, including those under development or in construction, in the aggregate, represent approximately 6,700 MW of power generation capacity. Power plants and power supply in Canada account for approximately 83 per cent of this total, and power plants in the U.S. account for the balance, being approximately 17 per cent.

TransCanada owns and operates:

- natural gas-fired cogeneration plants in Alberta at Carseland (80 MW), Redwater (40 MW), Bear Creek (80 MW) and MacKay River (165 MW);
- the Grandview natural gas-fired cogeneration plant (90 MW) near Saint John, New Brunswick;
- a waste-heat fuelled power plant at the Cancarb facility in Medicine Hat, Alberta (27 MW);
- a natural gas-fired, combined-cycle Ocean State Power plant in Burrillville, Rhode Island (560 MW); and
- hydroelectric generation assets in New Hampshire, Vermont and Massachusetts (567 MW).

TransCanada has long-term power purchase arrangements in place for:

- 100 per cent of the production of the Sundance A (560 MW) and a 50 per cent interest, through a partnership, in the production of the Sundance B (353 MW of 706 MW) power facilities near Wabamun, Alberta; and
- 756 MW of the production from the Sheerness facility near Hanna, Alberta.

TransCanada owns, but does not operate:

- a 47.9 per cent partnership interest at Year End, in the Bruce A nuclear power generation facility in Ontario (718.5 MW of a total of 1,500 MW that is currently in operation. Another 1,500 MW of which 718.5 MW are attributable to TransCanada, will be generated from two other units currently under refurbishment with restart expected beginning in 2009);

a 31.6 per cent partnership interest in the Bruce B nuclear power generation facilities in Ontario (1,011 MW of a total of 3,200 MW that is in operation); and

a 16.7 per cent interest in Huron Wind L.P. whose assets are located at the Bruce site (2 MW of a total of 9 MW that is in operation).

TransCanada owns the following facilities which are under construction or development:

- the 550 MW Bécancour natural gas-fired cogeneration plant near Trois-Rivières, Québec, which is expected to be in commercial service in late 2006; and

- a 62 per cent interest in Cartier Wind Energy which will construct six wind energy projects in the Gaspé region of Québec over the period 2006 to 2012 (458 MW of a total of 739.5 MW).

Further information about TransCanada's power holdings and significant developments and opportunities relating to power can be found in the MD&A under the headings "Power", "Power Financial Analysis" and "Power Opportunities and Developments". In particular, information about TransCanada's Eastern and Western power operations and about TransCanada's divestiture of Power LP to EPCOR, can be found under the heading "Power" in the MD&A.

Other Interests

Cancarb Limited

TransCanada owns Cancarb Limited, a world scale thermal carbon black manufacturing facility located in Medicine Hat, Alberta.

TransCanada Turbines

TransCanada owns a 50 per cent interest in TransCanada Turbines Ltd., a repair and overhaul business for aero-derivative industrial gas turbines. This business operates primarily out of facilities in Calgary, Alberta, with offices in Bakersfield, California; East Windsor, Connecticut; and Liverpool, England.

TransCanada Calibrations

TransCanada owns an 80 per cent interest in TransCanada Calibrations Ltd., a gas meter calibration business certified by Measurement Canada, located at Ile des Chênes, Manitoba.

HEALTH, SAFETY AND ENVIRONMENT

TransCanada is committed to providing a safe and healthy environment for its employees and the public, and to the protection of the environment. Health, safety and environment ("*HS&E*") is a priority in all of TransCanada's operations. The HS&E Committee of TransCanada's Board of Directors ("*Board*") monitors compliance with the TransCanada HS&E corporate policy through regular reporting by TransCanada's department of Community, Safety & Environment. TransCanada's senior executives are also committed to ensuring TransCanada is in compliance with its policies and is an industry leader. Senior executives are regularly advised of all important operational issues and initiatives relating to HS&E by way of a formal reporting process. In addition, TransCanada's management system and performance in the HS&E area are assessed by an independent outside firm every three years or more often if the HS&E Committee requests it. The most recent assessment was completed by PricewaterhouseCoopers in January 2004. These assessments involve senior executive interviews, review of policies and objectives, performance measurement and reporting.

TransCanada has an HS&E management system modeled after elements of the International Organization for Standardization's standard for environmental management systems which is known as ISO 14001, to facilitate the focus of resources on the areas of greatest risk to the organization's business activities relating to HS&E. The system highlights opportunities for improvement, enables TransCanada to work towards defined HS&E expectations and objectives, and provides a competitive business advantage. HS&E outside, independent assessments, management system assessments and planned inspections are used to assess both the effectiveness of implementation of HS&E programs, processes and procedures, and TransCanada's compliance with regulatory requirements.

TransCanada employs full-time staff dedicated to HS&E matters, and incorporates HS&E policies and principles into the planning, development, construction and operation of all its projects. Environmental protection requirements have not had a material impact on the capital expenditures of TransCanada to date; however, there can be no assurance that such requirements will not have a material impact on TransCanada's financial or operating results in future years. Such

requirements can be dependent on a variety of factors including the regulatory environment in which TransCanada operates.

Environment

Climate change is a strategic issue for TransCanada. In Canada, TransCanada's fossil fuelled power plants, pipeline assets and carbon black facilities are expected to be covered under legislation for large final emitters. While the broad elements of the proposed regulations to reduce greenhouse gas emissions intensities from large industrial emitters have been established, key policy elements remain outstanding including details of compliance options that entities may use to fulfill compliance obligations. At this time, it is difficult to determine the level of impact to TransCanada's Canadian assets until these and other key policy elements have been defined.

In 2006, TransCanada will continue with its strategy for managing the climate change issue. This strategy includes activities such as:

- energy conservation through improvements to overall system efficiency;
- conducting research and development work designed to reduce greenhouse gas emissions;
- gaining experience with flexible market mechanisms;
- participation in government-led policy forums; and
- taking part in public awareness initiatives and education programs focused on climate change and air quality issues.

In addition to these activities, TransCanada also ensures that the potential business risks and opportunities posed by increasing environmental priorities are considered when making decisions regarding TransCanada's businesses.

LEGAL PROCEEDINGS

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

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

TRANSFER AGENT AND REGISTRAR

TransCanada's transfer agent and registrar is Computershare Trust Company of Canada with transfer facilities in the Canadian cities of Vancouver, Calgary, Winnipeg, Toronto, Montréal and Halifax.

INTEREST OF EXPERTS

TransCanada's auditor is KPMG LLP ("*External Auditor*") and as of February 27, 2006, the partners of the External Auditor have advised that they do not beneficially own, directly or indirectly, any securities of TransCanada. TransCanada collects this information from the External Auditor but otherwise has no direct knowledge of individual holdings of its securities.

RISK FACTORS

A number of factors, including but not limited to those discussed in this section, could cause actual results or events to differ materially from current expectations.

Gas Transmission

TransCanada faces competition in its gas transmission business at both the supply and market ends of its systems. The competition is a result of other pipelines accessing an increasingly mature western Canadian sedimentary basin and serving some of the same markets as TransCanada. In addition, the continued expiration of firm transportation contracts has resulted in significant reductions in firm contracted capacity on both the Canadian Mainline and Alberta System. As well, regulatory decisions continue to have significant impact on the financial returns for and future investments in TransCanada's Canadian wholly-owned pipelines.

Further information about risks in TransCanada's natural gas transmission business can be found under the headings "Gas Transmission Opportunities and Developments" and "Gas Transmission Business Risks" in the MD&A.

Power

TransCanada's power business can be affected by a variety of factors including competition from other market participants, fluctuating market demand, weather, reliance on the supply of feed stocks such as natural gas, water, coal and uranium, fluctuating feed stock prices, fluctuating electricity prices, unexpected outages, third party power plant operator performance, power transmission disruptions and regulatory changes and influences.

Further information about competition risks in TransCanada's power business can be found under the headings "Power Opportunities and Developments" and "Power Business Risks" in the MD&A.

In addition, Bruce A and Bruce B, in which TransCanada holds material interests, are subject to risks related to the operation and maintenance of nuclear power generating facilities, including risks relating to the use, handling, containment and storage of radioactive materials; limitation on the amounts and types of insurance that are commercially available to cover any related liabilities that may arise from these operations; changes in and varying interpretations of the extensive federal regulations that apply to Bruce A's and Bruce B's nuclear operations; modifications needed to meet increasing security requirements; and repairs, modifications, replacements and outages that may be necessitated as a result of testing and inspection programs which, themselves, may need to be enhanced in coming years to improve operations or satisfy increasing regulatory or other requirements.

Other

Further information about TransCanada's risk management activities can be found under the heading "Risk Management" in the MD&A.

DIVIDENDS

TransCanada's Board of Directors has not adopted a formal dividend policy. The Board reviews the financial performance of TransCanada quarterly and makes a determination of the appropriate level of dividends to be declared in the following quarter. Currently, TransCanada's payment of dividends on its common shares is funded from dividends TransCanada receives as the sole common shareholder of TCPL. Provisions of various trust indentures and credit arrangements to which TCPL is a party, restrict TCPL's ability to declare and pay dividends to TransCanada under certain circumstances and, if such restrictions apply, they may, in turn, have an impact on TransCanada's ability to declare and pay dividends on its common shares. In the opinion of TransCanada management, such provisions do not restrict or alter TransCanada's ability to declare or pay dividends.

The dividends declared per common share of TransCanada during the past three completed financial years are set forth in the following table:

	2005	2004	2003
Dividends declared on common shares[(1)]	**$1.22**	$1.16	$1.08

(1) Prior to May 15, 2003, dividends were paid by TCPL.

DESCRIPTION OF CAPITAL STRUCTURE

Share Capital

TransCanada's authorized share capital consists of an unlimited number of common shares, of which approximately 487,235,725 were issued and outstanding at Year End, and an unlimited number of first preferred shares and second preferred shares issuable in series, of which none are outstanding. The following is a description of the material characteristics of each of these classes of shares.

Common Shares

The common shares entitle the holders thereof to one vote per share at all meetings of shareholders, except meetings at which only holders of another specified class of shares are entitled to vote, and, subject to the rights, privileges, restrictions and conditions attaching to the first preferred shares and the second preferred shares, whether as a class or a series, and to any other class or series of shares of TransCanada which rank prior to the common shares, entitle the holders thereof to receive (i) dividends if, as and when declared by the Board out of the assets of TransCanada properly applicable to the payment of the dividends in such amount and payable at such times and at such place or places as the Board may from time to time determine and (ii) the remaining property of TransCanada upon a dissolution.

First Preferred Shares

Subject to certain limitations, the Board may, from time to time, issue first preferred shares in one or more series and determine for any such series, its designation, number of shares and respective rights, privileges, restrictions and conditions. The first preferred shares as a class, have, among others, provisions to the following effect.

The first preferred shares of each series shall rank on a parity with the first preferred shares of every other series, and shall be entitled to preference over the common shares, the second preferred shares and any other shares ranking junior to the first preferred shares with respect to the payment of dividends, the repayment of capital and the distribution of assets of TransCanada in the event of a liquidation, dissolution or winding up of TransCanada.

Except as provided by the *Canada Business Corporations Act* or as referred to below, the holders of the first preferred shares will not have any voting rights nor will they be entitled to receive notice of or to attend shareholders' meetings. The holders of any particular series of first preferred shares will, if the directors so determine prior to the issuance of such series, be entitled to such voting rights as may be determined by the directors if TransCanada fails to pay dividends on that series of preferred shares for any period as may be so determined by the directors.

The provisions attaching to the first preferred shares as a class may be modified, amended or varied only with the sanction of the holders of the first preferred shares as a class. Any such sanction to be given by the holders of the first preferred shares may be given by the affirmative vote of the holders of not less than $66^2/_3$ per cent of the first preferred shares represented and voted at a meeting or adjourned meeting of such holders.

Second Preferred Shares

The rights, privileges, restrictions and conditions attaching to the second preferred shares are substantially identical to those attaching to the first preferred shares, except that the second preferred shares are junior to the first preferred shares with respect to the payment of dividends, repayment of capital and the distribution of assets of TransCanada in the event of a liquidation, dissolution or winding up of TransCanada.

CREDIT RATINGS

Although TransCanada has not issued debt, it has been assigned an issuer rating by Moody's Investors Service of A3 with a stable outlook. TransCanada does not presently intend to issue debt securities in its own name and future financing requirements are expected to continue to be funded through its subsidiary, TCPL. The following table sets out the credit ratings assigned to those outstanding classes of securities of TCPL which have been rated:

Overall	**DBRS**	**Moody's**	**S&P**
Senior Secured Debt			
First Mortgage Bonds	A	A2	A
Senior Unsecured Debt			
Debentures	A	A2	A
Medium-term Notes	A	A2	A
Subordinated Debt	A (low)	A3	BBB+
Junior Subordinated Debt	Pfd-2	A3	BBB
Preferred Shares	Pfd-2 (low)	Baa1	BBB
Commercial Paper	R-1 (low)	P-1	
Trend/Rating Outlook	Stable	Stable	Negative

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. Credit ratings are not recommendations to purchase, hold or sell securities and do not address the market price or suitability of a specific security for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant. A description of the rating agencies' credit ratings listed in the table above is set out below.

Dominion Bond Rating Service (DBRS)

DBRS has different rating scales for short and long-term debt and preferred shares. "High" or "low" grades are used to indicate the relative standing within a rating category. The absence of either a "high" or "low" designation indicates the rating is in the "middle" of the category. The R-1 (low) rating assigned to TCPL's short-term debt is the third highest of ten rating categories and indicates satisfactory credit quality. The overall strength and outlook for key liquidity, debt and profitability ratios is not normally as favourable as with higher rating categories, but these considerations are still respectable. Any qualifying negative factors that exist are considered manageable, and the entity is normally of sufficient size to have some influence in its industry. The A ratings assigned to TCPL's senior secured and senior unsecured debt and the A (low) rating assigned to its subordinated debt are the third highest of ten categories for long-term debt. Long-term debt rated A is of satisfactory credit quality. Protection of interest and principal is still substantial, but the degree of strength is less than that of AA rated entities. While a respectable rating, entities in the A category are considered to be more susceptible to adverse economic conditions and have greater cyclical tendencies than higher rated entities. The Pfd-2 and Pfd-2 (low) ratings assigned to TCPL's junior subordinated debt and preferred shares are the second highest of six rating categories for preferred shares. Preferred shares rated Pfd-2 are of satisfactory credit quality. Protection of dividends and principal is still substantial; however, earnings, the balance sheet and coverage ratios are not as strong as Pfd-1 rated companies.

Moody's Investor Services (Moody's)

Moody's has different rating scales for short and long-term obligations. Numerical modifiers 1, 2 and 3 are applied to each rating classification, with 1 being the highest and 3 being the lowest. The P-1 rating assigned to TCPL's short-term debt is the highest of four rating categories and indicates a superior ability to repay short-term debt obligations. The A2 ratings assigned to TCPL's senior secured and senior unsecured debt and the A3 ratings assigned to its subordinated debt and junior subordinated debt are the third highest of nine rating categories for long-term obligations. Obligations rated A are considered upper-medium grade and are subject to low credit risk. The Baa1 rating assigned to TCPL's preferred shares is the fourth highest of nine rating categories for long-term obligations. Obligations rated Baa are subject to moderate credit risk, are considered medium-grade, and as such, may possess certain speculative characteristics.

Standard & Poor's (S&P)

S&P has different rating scales for short and long-term obligations. Ratings may be modified by the addition of a plus (+) or minus (-) sign to show the relative standing within a particular rating category. The A and A- ratings assigned to TCPL's senior secured and senior unsecured debt, respectively, are the third highest of ten rating categories for long-term obligations. An A rating indicates the obligor's capacity to meet its financial commitment is strong; however, the obligation is somewhat susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rated categories. The BBB+ rating assigned to TCPL's subordinated debt and the BBB ratings assigned to its junior subordinated debt and preferred shares are the fourth highest of ten rating categories for long-term obligations. An obligation rated BBB exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation.

MARKET FOR SECURITIES

TransCanada's common shares are listed on the Toronto Stock Exchange ("*TSX*") and the New York Stock Exchange ("*NYSE*"). The following table sets forth the reported monthly high and low closing prices and monthly trading volumes of the common shares of TransCanada on the TSX for the period indicated:

Common Shares (TRP)

Month	High ($)	Low ($)	Volume Traded
December, 2005	37.56	36.25	16,433,655
November, 2005	37.40	34.95	21,148,781
October, 2005	36.00	34.60	20,786,022
September, 2005	36.94	32.92	26,394,804
August, 2005	33.69	31.49	18,358,190
July, 2005	34.08	32.06	16,695,178
June, 2005	32.59	30.32	20,470,296
May, 2005	31.10	29.80	16,560,238
April, 2005	30.00	29.55	17,071,520
March, 2005	30.61	29.20	23,363,461
February, 2005	30.69	29.70	19,187,511
January, 2005	30.48	29.75	21,563,721

In addition, the following securities of TransCanada's subsidiary, TCPL, are listed on the markets specified:

TCPL's Cumulative Redeemable First Preferred Shares, Series U and Series Y are listed on the TSX;

TCPL's 8.25% preferred securities due 2047, are listed on the NYSE; and

TCPL's 16.50% First Mortgage Pipe Line Bonds due 2007, are listed on the London Stock Exchange.

DIRECTORS AND OFFICERS

As of February 27, 2006, the directors and officers of TransCanada as a group beneficially owned, directly or indirectly, have exercisable options to own, or exercised control or direction over, 2,334,652 common shares of TransCanada which constitutes less than one per cent of TransCanada's common shares and less than one per cent of the voting securities of any of its subsidiaries or affiliates. TransCanada collects this information from its directors and officers but otherwise has no direct knowledge of individual holdings of its securities. Further information as to securities beneficially owned, or over which control or direction is exercised, is provided in TransCanada's Management Proxy Circular dated February 28, 2006 ("*Proxy Circular*") under the heading "Business to be Transacted at the Meeting Election of Directors". See also "Additional Information" in this AIF.

Directors

Set forth below are the names of the twelve directors who served on TransCanada's Board at Year End, together with their jurisdictions of residence, all positions and offices held by them with TransCanada and its significant affiliates, their principal occupations or employment during the past five years and the year from which each director has continually served as a director of TransCanada and, prior to the arrangement, with TCPL. Positions and offices held with TransCanada are also held by such person at TCPL.

Name and Place of Residence	**Principal Occupation During the Five Preceding Years**	**Director Since**
Douglas D. Baldwin Calgary, Alberta Canada	Chairman, Talisman Energy Inc., (oil and gas) since May 2003. President and Chief Executive Officer, TCPL, from August 1999 to April 2001. Director, Citadel Group of Funds. Member, Board of Governors, University of Calgary.	1999
Kevin E. Benson[(1)] Wheaton, Illinois United States	President and Chief Executive Officer, Laidlaw International, Inc. (transportation services) since June 2003, and Laidlaw, Inc. from September 2002 to June 2003. President and Chief Executive Officer, The Insurance Corporation of British Columbia from December 2001 until September 2002. President, The Pattison Group from April 2000 to February 2001. Director, Laidlaw International, Inc.	2005
Derek H. Burney, O.C. Ottawa, Ontario Canada	Corporate Director. President and Chief Executive Officer, CAE Inc. (technology) from October 1999 to August 2004. Lead director at Quebecor World Inc. (communications and media) from April 2003 to November 2005. Director, CanWest Global Communications Corp., Chair, New Brunswick Power Corporation and Lead Director, Shell Canada Limited.	2005
Wendy K. Dobson Uxbridge, Ontario Canada	Professor, Rotman School of Management and Director, Institute for International Business, University of Toronto (education). Director, Toronto-Dominion Bank. Vice Chair, Canadian Public Accountability Board.	1992
E. Linn Draper, Jr. Lampasas, Texas United States	Corporate Director. Chairman, President and Chief Executive Officer of Columbus, Ohio-based American Electric Power Co., Inc. from April 1993 to April 2004. Director, Alliance Data Systems Corporation, Alpha Natural Resources, Inc. and Temple-Inland Inc. Chair of NorthWestern Corporation.	2005

The Hon. Paule Gauthier, P.C., O.C., O.Q., Q.C. Québec, Québec Canada	Senior Partner, Desjardins Ducharme L.L.P. (law firm). President, Institut Québecois des Hautes Études Internationales, Laval University. Director, Royal Bank of Canada, Rothmans Inc., Metro Inc. and RBC Dexia Investor Services Trust.	2002
Kerry L. Hawkins Winnipeg, Manitoba Canada	Corporate Director. President, Cargill Limited (agricultural) from September 1982 to December 2005. Director, NOVA Chemicals Corporation and Shell Canada Limited.	1996
S. Barry Jackson Calgary, Alberta Canada	Corporate Director. Chairman, Resolute Energy Inc. (oil and gas) from January 2002 to April 2005 and Chairman, Deer Creek Energy Limited (oil and gas) from April 2001 to September 2005. Director, Nexen Inc., Cordero Energy Inc. and privately held Larincina Energy Ltd.	2002
Paul L. Joskow Brookline, Massachusetts United States	Professor, Department of Economics, Massachusetts Institute of Technology (MIT) (education). Director of the MIT Center for Energy and Environmental Policy Research. Director, National Grid PLC and trustee, Putnam Mutual Funds.	2004
Harold N. Kvisle Calgary, Alberta Canada	President and Chief Executive Officer, TransCanada since May 2003 and TCPL since May 2001. Executive Vice-President, Trading and Business Development, TCPL, from June 2000 to April 2001. Director, PrimeWest Energy Inc. and Bank of Montreal. Chair, Mount Royal College.	2001
David P. O'Brien[(2)] Calgary, Alberta Canada	Chairman and Chief Executive Officer, PanCanadian Energy Corporation (oil and gas) from October 2001 to April 2002. Chairman, President and Chief Executive Officer, Canadian Pacific Limited (transportation, energy and hotels) from May 1996 to October 2001. Chair, EnCana Corporation (oil and gas) since April 2002 and Chair, Royal Bank of Canada (banking) since February 2004. Director, Fairmont Hotels & Resorts Inc., Inco Limited, Molson Coors Brewing Company, and the not for profit C.D. Howe Institute. Chancellor, Concordia University.	2001
Harry G. Schaefer, F.C.A. Calgary, Alberta Canada	President, Schaefer & Associates (business advisory services). Vice-Chairman of the Board, TransCanada since May 2003 and TCPL since June 1998. Director, Agrium Inc. and Fording Canadian Coal Trust.	1987

(1) Mr. Benson was President and Chief Executive Officer of Canadian Airlines International Ltd. from July 1996 to February 2000. Canadian Airlines International Ltd. filed for protection under the *Companies' Creditors Arrangement Act* (Canada) and applicable bankruptcy protection statutes in the United States on March 24, 2000.

(2) Mr. O'Brien was a director of Air Canada on April 1, 2003 when Air Canada filed for protection under the *Companies' Creditors Arrangement Act* (Canada). Mr. O'Brien resigned as a director from Air Canada in November 2003.

Each director holds office until the next annual meeting or until his or her successor is earlier elected or appointed. Mr. Jackson was designated as the Chair of the Board on April 29, 2005, Mr. Draper was appointed to the Board on June 15, 2005 and Mr. Burney was appointed to the Board on September 8, 2005. Mr. W. Thomas Stephens, a TransCanada director since April 1999, resigned from the Board on August 12, 2005.

Officers

All of the executive officers and corporate officers of TransCanada reside in Calgary, Alberta, Canada. References to positions and offices with TransCanada prior to May 15, 2003 are references to the positions and offices held with TCPL. Current positions and offices held with TransCanada are also held by such person at TCPL. As of the date hereof, the officers of TransCanada, their present positions within TransCanada and their principal occupations during the five preceding years are as follows:

Executive Officers

Name	Present Position Held	Principal Occupation During the Five Preceding Years
Harold N. Kvisle	President and Chief Executive Officer	Prior to April 2001, Executive Vice-President, Trading and Business Development.
Albrecht W.A. Bellstedt, Q.C.[(1)]	Executive Vice-President, Law and General Counsel and Chief Compliance Officer	Prior to September 2005, Executive Vice-President, Law and General Counsel.
Russell K. Girling	Executive Vice-President, Corporate Development and Chief Financial Officer	Prior to March 2003, Executive Vice-President and Chief Financial Officer.
Dennis J. McConaghy	Executive Vice-President, Gas Development	Prior to May 2001, Senior Vice-President, Business Development.
Alexander J. Pourbaix	Executive Vice-President, Power	Executive Vice-President, Power Development, May 2001 to March 2003. Prior to May 2001, Senior Vice-President, Power Ventures.
Sarah E. Raiss	Executive Vice-President, Corporate Services	Prior to January 2002, Executive Vice-President, Human Resources and Public Sector Relations.
Ronald J. Turner	Executive Vice-President, Gas Transmission	Prior to March 2003, Executive Vice-President, Operations and Engineering.
Donald M. Wishart	Executive Vice-President, Operations and Engineering	Prior to March 2003, Senior Vice-President, Field Operations.

(1) Mr. Bellstedt, who served as a trustee of Atlas Cold Storage Income Trust, was subject to an Ontario Securities Commission cease trade order issued in respect of all insiders of Atlas Cold Storage Income Trust on December 2, 2003 which arose because of late filed financial statements required to reflect certain re-statements. The cease trade order was rescinded in January 2004.

Corporate Officers

Name	Present Position Held	Principal Occupation During the Five Preceding Years
Ronald L. Cook	Vice-President, Taxation	Prior to April 2002, Director, Taxation.
Rhondda E.S. Grant	Vice-President, Communications and Corporate Secretary	Prior to February 2005, Vice-President and Corporate Secretary.
Lee G. Hobbs	Vice-President and Controller	Prior to July 2001, Director, Accounting.
Garry E. Lamb	Vice-President, Risk Management	Prior to October 2001, Vice-President, Audit and Risk Management.
Donald R. Marchand	Vice-President, Finance and Treasurer	Vice-President, Finance and Treasurer

CORPORATE GOVERNANCE

The Board and the members of TransCanada's management are committed to the highest standards of corporate governance. TransCanada's corporate governance practices comply with the governance rules of the Canadian Securities Administrators ("*CSA*"), those of the NYSE applicable to foreign issuers and of the U.S. Securities and Exchange Commission ("*SEC*"), and those mandated by the United States *Sarbanes-Oxley Act of 2002* ("*SOX*"). As a non-U.S. company, TransCanada is not required to comply with most of the NYSE corporate governance listing standards; however, except as summarized on its website at www.transcanada.com, the governance practices followed are in compliance with the NYSE standards for U.S. companies in all significant respects. TransCanada is in compliance with the CSA's Multilateral Instrument 52-110 pertaining to audit committees. TransCanada is also in compliance with National Policy 58-201, Corporate Governance Guidelines, and National Instrument 58-101, Disclosure of Corporate Governance Practices (collectively, the "*Canadian Governance Guidelines*"). In 2005, the Canadian Governance Guidelines came into effect and for purposes of the TSX replaced the TSX Corporate Governance Guidelines.

Audit Committee

TransCanada has an Audit Committee which is responsible for assisting the Board in overseeing the integrity of TransCanada's financial statements and compliance with legal and regulatory requirements and in ensuring the independence and performance of TransCanada's internal and external auditors. The members of the Audit Committee at Year End were Harry G. Schaefer (Chair), Douglas D. Baldwin, Kevin E. Benson, Paule Gauthier and Paul L. Joskow. Mr. Jackson is a non-voting member of the Audit Committee.

The Board believes that the composition of the Audit Committee reflects a high level of financial literacy and expertise. Each member of the Audit Committee has been determined by the Board to be "independent" and "financially literate" within the meaning of the definitions under Canadian and U.S. securities laws and the NYSE rules. In addition, the Board has determined that Mr. Schaefer is an "Audit Committee Financial Expert" as that term is defined under U.S. securities laws. The Board has made these determinations based on the education and breadth and depth of experience of each member of the Audit Committee. The following is a description of the education and experience, apart from their respective roles as directors of TransCanada, of each member of the Audit Committee that is relevant to the performance of his or her responsibilities as a member of the Audit Committee:

Mr. Schaefer earned a Bachelor of Commerce from the University of Alberta, is a Chartered Accountant and is a Fellow of the Canadian Institute of Chartered Accountants. He serves on and has served on the boards of several public companies and other organizations, including as Chairman of the Alberta Chapter of the Institute of Corporate

Directors, and on the audit committees of certain of those boards. Mr. Schaefer has also held several executive positions with public companies. He is currently Chair of the Audit Committee and of the audit committees of two other public companies.

Mr. Baldwin earned a Bachelor of Science in Chemical Engineering from the University of Saskatchewan. He has served on the boards of several public companies and other organizations and on the audit committees of certain of those boards. Mr. Baldwin has also held the position of President and Chief Executive Officer of TCPL and other senior executive positions with Imperial Oil Limited and Esso Resources Canada Limited. Mr. Baldwin will retire from the Board at the Annual Meeting of Shareholders to be held on April 28, 2006.

Mr. Benson earned a Bachelor of Accounting from the University of Witwatersrand (South Africa) and was a member of the South African Society of Chartered Accountants. Mr. Benson is the President and Chief Executive Officer of Laidlaw International, Inc. In prior years, he has held several executive positions including one as President and Chief Executive Officer of Canadian Airlines International Ltd. and has served on other public company boards.

Mme. Gauthier earned a Bachelor of Arts from the Collège Jésus-Marie de Sillery, a Bachelor of Laws from Laval University and a Master of Laws in Business Law (Intellectual Property) from Laval-University. She has served on the boards of several public companies and other organizations and on the audit committees of certain of those boards.

Mr. Joskow earned a Bachelor of Arts with Distinction in Economics from Cornell University, a Masters of Philosophy in Economics from Yale University, and Ph.D. in Economics from Yale University. He has served on the boards of several public companies and other organizations and on the audit committees of certain of those.

The Charter of the Audit Committee can be found in Schedule "B" of this AIF and on TransCanada's website under the Corporate Governance Board Committees page, at the link specified above under the heading "Corporate Governance".

Pre-Approval Policies and Procedures

TransCanada's Audit Committee has adopted a pre-approval policy with respect to permitted non-audit services. Under the policy, the Audit Committee has granted pre-approval for specified non-audit services. For engagements of $25,000 or less which are not within the annual pre-approved limit approval by the Audit Committee is not required, and for engagements between $25,000 and $100,000, approval of the Audit Committee chair is required, and in both instances the Audit Committee is to be informed of the engagement at the next scheduled Audit Committee meeting. For all engagements of $100,000 or more, pre-approval of the Audit Committee is required. In all cases, regardless of the dollar amount involved, where there is a potential for conflict of interest involving the external auditor on an engagement, the Audit Committee chair must pre-approve the assignment.

To date, TransCanada has not approved any non-audit services on the basis of the de-minimis exemptions. All non-audit services have been pre-approved by the Audit Committee in accordance with the pre-approval policy described above.

External Auditor Service Fees

The aggregate fees for external auditor services rendered by the External Auditor for TransCanada and its subsidiaries in each of 2005 and 2004 fiscal years, are shown in the table below:

Fee Category	2005	2004	Description of Fee Category
	(millions of dollars)		
Audit Fees	**3.15**	2.50	Aggregate fees for audit services rendered by TransCanada's External Auditor for the audit of TransCanada's and its subsidiaries' annual financial statements or services provided in connection with statutory and regulatory filings or engagements, the review of interim consolidated financial statements and information contained in various prospectuses and other offering documents.
Audit Related Fees	**0.11**	0.06	Aggregate fees for assurance and related services rendered by TransCanada's External Auditor that are reasonably related to performance of the audit or review of TransCanada's financial statements and are not reported as Audit Fees. The nature of services comprising these fees related to the audit of the financial statements of TransCanada's various pension plans.
Tax Fees	**0.12**	0.06	Aggregate fees rendered by TransCanada's External Auditor for tax compliance and tax advice. The nature of these services consisted of: tax compliance including the review of Canadian and U.S. income tax returns; and tax items and tax services related to domestic and international taxation including income tax, capital tax and Goods and Services Tax.
All Other Fees	**0.14**	0.05	Aggregate fees for products and services other than those reported in this table above rendered by TransCanada's External Auditor. The nature of these services consisted of advice with respect to TransCanada's compliance with SOX.
Total	**3.52**	2.67	

Other Board Committees

In addition to the Audit Committee, TransCanada has three other Board committees: the Governance Committee, the Health, Safety and Environment Committee and the Human Resources Committee. Mr. Jackson, the Chair of the Board, sits on each of Board's committees as a non-voting member. The voting members of each of these committees, as of Year End, are identified below:

Governance Committee		**Health, Safety & Environment Committee**		**Human Resources Committee**	
Chair:	W.K. Dobson	Chair:	D.D. Baldwin	Chair:	K.L. Hawkins
Members:	D.H. Burney	Members:	E.L. Draper	Members:	W.K. Dobson
	P.L. Joskow		P. Gauthier		E.L. Draper
	D.P. O'Brien		K.L. Hawkins		D.P. O'Brien
	H.G. Schaefer				

The charters of the Governance Committee, the Health, Safety & Environment Committee and the Human Resources Committee are attached as Schedules "C", "D" and "E", respectively, and can be found on TransCanada's website under the Corporate Governance Board Committees page at the link specified below.

Further information about TransCanada's Board committees and corporate governance can be found in the Proxy Circular under the heading "Corporate Governance" or on TransCanada's website located at: http://www.transcanada.com/company/board_committees.html.

Conflicts of Interest

The Board and members of TransCanada's management are not aware of any existing or potential material conflicts of interest between TransCanada or a subsidiary and any director or officer of TransCanada or its subsidiary. Directors and officers of TransCanada and its subsidiaries are required to disclose the existence of existing or potential conflicts in accordance with TransCanada policies governing directors and officers and in accordance with the *Canada Business Corporations Act*. If a director or officer has such a conflict, TransCanada requires that the director or officer absent himself or herself from any discussion or voting relating to the matter giving rise to the material existing or potential conflict.

ADDITIONAL INFORMATION

1. Additional information in relation to TransCanada may be found under TransCanada's profile on SEDAR at www.sedar.com.

2. Additional information including directors' and officers' remuneration and indebtedness, principal holders of TransCanada's securities and securities authorized for issuance under equity compensation plans (all where applicable), is contained in TransCanada's Proxy Circular for its most recent annual meeting of shareholders that involved the election of directors and can be obtained upon request from the Corporate Secretary of TransCanada.

3. Additional financial information is provided in TransCanada's audited consolidated financial statements and MD&A for its most recently completed financial year.

GLOSSARY

AIF	Annual Information Form of TransCanada Corporation dated February 27, 2006
Alberta System	A natural gas transmission system throughout the province of Alberta
Annual Report	TransCanada's Annual Report to Shareholders for the year ended, December 31, 2005
APG	Aboriginal Pipeline Group or Mackenzie Valley Aboriginal Pipeline Limited Partnership
Bcf	Billion cubic feet
BC System	A natural gas transmission system in southeastern B.C.
Bécancour Plant	A power plant near Trois-Rivières, Québec
Board	TransCanada's Board of Directors
Bruce A	Bruce Power A L.P.
Bruce B	Bruce Power L.P.
Canadian Mainline	A natural gas pipeline system running from the Alberta border east to delivery points in eastern Canada and along the U.S. border
CSA	Canadian Securities Administrators
EUB	Alberta Energy and Utilities Board
External Auditor	KPMG LLP
FERC	Federal Energy Regulatory Commission (USA)
Foothills	Foothills Pipe Lines Ltd.
Foothills System	A natural gas pipeline system in southeastern B.C., southern Alberta and southwestern Saskatchewan
Grandview Plant	A power plant in Saint John, New Brunswick
Great Lakes System	A natural gas pipeline system in the north central U.S., roughly parallel to the Canada-U.S. Border
HS&E	Health, Safety and Environment
Iroquois System	A natural gas pipeline system in New York
LNG	Liquefied Natural Gas
Mackenzie Producers	Mackenzie Delta Producers Group
MD&A	TransCanada's Management's Discussion and Analysis dated February 27, 2006
MW	Megawatts
NBPL	Northern Border Pipeline
NEB	National Energy Board
NEGT	National Energy & Gas Transmission, Inc.
NGTL	NOVA Gas Transmission Ltd.
Northern Border Pipeline	Northern Border Pipeline Company
NYSE	New York Stock Exchange
OPG	Ontario Power Generation Inc.
Power LP	TransCanada Power, L.P.
Proxy Circular	TransCanada's Management Proxy Circular dated February 28, 2006
SEC	U.S. Securities and Exchange Commission
Shell	Shell US Gas & Power LLC
SOX	U.S. *Sarbanes-Oxley Act* of 2002
Tcf	Trillion cubic feet
TCPL	TransCanada PipeLines Limited
TQM	Trans Québec & Maritimes Pipeline Inc.
TQM System	A natural gas pipeline system in southeastern Québec
TransCanada	TransCanada Corporation
TSX	Toronto Stock Exchange
Tuscarora	Tuscarora Gas Transmission Company
USGen	US Gen New England, Inc.
Year End	December 31, 2005

SCHEDULE "A"

Exchange Rate of the Canadian Dollar

All dollar amounts in the AIF are in Canadian dollars, except where otherwise indicated. The following table shows the yearly high and low noon rates, the yearly average noon rates and the year-end noon spot rates for the U.S. dollar for the past five years, each expressed in Canadian dollars, as reported by the Bank of Canada.

	Year Ended				
	2005	**2004**	**2003**	**2002**	**2001**
Yearly High Noon Rate	**1.2704**	1.3968	1.5747	1.6021	1.5593
Yearly Low Noon Rate	**1.1507**	1.1774	1.2924	1.4936	1.4341
Yearly Average Noon Rate	**1.2116**	1.3016	1.4014	1.5484	1.4852
Year-End Noon Rate	**1.1659**	1.2036	1.2924	1.5926	1.5002

On February 27, 2006, the noon rate for the U.S. dollar as reported by the Bank of Canada was US $1.00 = Cdn. $1.1420.

Metric Conversion Table

The conversion factors set out below are approximate factors. To convert from Metric to Imperial multiply by the factor indicated. To convert from Imperial to Metric divide by the factor indicated.

Metric	**Imperial**	**Factor**
Kilometres	Miles	0.62
Millimetres	Inches	0.04
Gigajoules	Million British thermal units	0.95
Cubic metres*	Cubic feet	35.3
Kilopascals	Pounds per square inch	0.15
Degrees Celsius	Degrees Fahrenheit	to convert to Fahrenheit multiply by 1.8, then add 32 degrees; to convert to Celsius subtract 32 degrees, then divide by 1.8

* The conversion is based on natural gas at a base pressure of 101.325 kilopascals and at a base temperature of 15 degrees Celsius.

SCHEDULE "B"
CHARTER OF
THE AUDIT COMMITTEE

1. Purpose

The Audit Committee shall assist the Board of Directors (the "Board") in overseeing and monitoring, among other things, the:

Company's financial accounting and reporting process;

integrity of the financial statements;

Company's internal control over financial reporting;

external financial audit process;

compliance by the Company with legal and regulatory requirements; and

independence and performance of the Company's internal and external auditors.

To fulfill its purpose, the Audit Committee has been delegated certain authorities by the Board of Directors that it may exercise on behalf of the Board.

2. Roles and Responsibilities

I.

Appointment of the Company's External Auditors

Subject to confirmation by the external auditors of their compliance with Canadian and U.S. regulatory registration requirements, the Audit Committee shall recommend to the Board the appointment of the external auditors, such appointment to be confirmed by the Company's shareholders at each annual meeting. The Audit Committee shall also recommend to the Board the compensation to be paid to the external auditors for audit services and shall pre-approve the retention of the external auditors for any permitted non-audit service and the fees for such service. The Audit Committee shall also be directly responsible for the oversight of the work of the external auditor (including resolution of disagreements between management and the external auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or related work. The external auditor shall report directly to the Audit Committee.

The Audit Committee shall also receive periodic reports from the external auditors regarding the auditors' independence, discuss such reports with the auditors, consider whether the provision of non-audit services is compatible with maintaining the auditors' independence and the Audit Committee shall take appropriate action to satisfy itself of the independence of the external auditors.

II.

Oversight in Respect of Financial Disclosure

The Audit Committee, to the extent it deems it necessary or appropriate, shall:

a) review, discuss with management and the external auditors and recommend to the Board for approval, the Company's audited annual financial statements, annual information form including management discussion and analysis, all financial statements in prospectuses and other offering memoranda, financial statements required by regulatory authorities, all prospectuses and all documents which may be incorporated by reference into a prospectus, including without limitation, the annual proxy circular, but excluding any pricing supplements issued

under a medium term note prospectus supplement of the Company;

b)

review, discuss with management and the external auditors and recommend to the Board for approval the release to the public of the Company's interim reports, including the financial statements, management discussion and analysis and press releases on quarterly financial results;

c)

review and discuss with management and external auditors the use of "pro forma" or "adjusted" non-GAAP information and the applicable reconciliation;

d)

review and discuss with management and external auditors financial information and earnings guidance provided to analysts and rating agencies; provided, however, that such discussion may be done generally (consisting of discussing the types of information to be disclosed and the types of presentations to be made). The Audit Committee need not discuss in advance each instance in which the Company may provide earnings guidance or presentations to rating agencies;

e)

review annual and quarterly financial statements and annual disclosure documents of NOVA Gas Transmission Ltd. ("NGTL");

f)

review with management and the external auditors major issues regarding accounting and auditing principles and practices, including any significant changes in the Company's selection or application of accounting principles, as well as major issues as to the adequacy of the Company's internal controls and any special audit steps adopted in light of material control deficiencies that could significantly affect the Company's financial statements;

g)

review and discuss quarterly reports from the external auditors on:

i)

all critical accounting policies and practices to be used;

ii)

all alternative treatments of financial information within generally accepted accounting principles that have been discussed with management, ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the external auditor;

iii)

other material written communications between the external auditor and management, such as any management letter or schedule of unadjusted differences;

h)

review with management and the external auditors the effect of regulatory and accounting initiatives as well as off-balance sheet structures on the Company's financial statements;

i)

review with management, the external auditors and, if necessary, legal counsel, any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Company, and the manner in which these matters have been disclosed in the financial statements;

j)

review disclosures made to the Audit Committee by the Company's CEO and CFO during their certification process for the periodic reports filed with securities regulators about any significant deficiencies in the design or operation of internal controls or material weaknesses therein and any fraud involving management or other employees who have a significant role in the Company's internal controls;

k)

discuss with management the Company's material financial risk exposures and the steps management has taken to monitor and control such exposures, including the Company's risk assessment and risk management policies;

III.

Oversight in Respect of Legal and Regulatory Matters

a) review with the Company's General Counsel legal matters that may have a material impact on the financial statements, the Company's compliance policies and any material reports or inquiries received from regulators or governmental agencies.

IV.

Oversight in Respect of Internal Audit

a)

review the audit plans of the internal auditors of the Company including the degree of coordination between such plan and that of the external auditors and the extent to which the planned audit scope can be relied upon to detect weaknesses in internal control, fraud or other illegal acts;

b)

review the significant findings prepared by the internal auditing department and recommendations issued by the Company or by any external party relating to internal audit issues, together with management's response thereto;

c)

review compliance with the Company's policies and avoidance of conflicts of interest;

d)

review the adequacy of the resources of the internal auditor to ensure the objectivity and independence of the internal audit function, including reports from the internal audit department on its audit process with associates and affiliates;

e)

ensure the internal auditor has access to the Chair of the Audit Committee and of the Board and to the Chief Executive Officer and meet separately with the internal auditor to review with him any problems or difficulties he may have encountered and specifically:

i)

any difficulties which were encountered in the course of the audit work, including restrictions on the scope of activities or access to required information, and any disagreements with management;

ii)

any changes required in the planned scope of the internal audit; and

iii)

the internal audit department responsibilities, budget and staffing;

and to report to the Board on such meetings;

f)

bi-annually review officers' expenses and aircraft usage reports;

V.

Oversight in Respect of the External Auditors

a)

review the annual post-audit or management letter from the external auditors and management's response and follow-up in respect of any identified weakness, inquire regularly of management and the external auditors of any significant issues between them and how they have been resolved, and intervene in the resolution if required;

b)

review the quarterly unaudited financial statements with the external auditors and receive and review the review engagement reports of external auditors on unaudited financial statements of the Company and NGTL;

c)

receive and review annually the external auditors' formal written statement of independence delineating all relationships between itself and the Company;

d)

meet separately with the external auditors to review with them any problems or difficulties the external auditors may have encountered and specifically:

i)

any difficulties which were encountered in the course of the audit work, including any restrictions on the scope of activities or access to required information, and any disagreements with management; and

ii) any changes required in the planned scope of the audit;

and to report to the Board on such meetings;

e) review with the external auditors the adequacy and appropriateness of the accounting policies used in preparation of the financial statements;

f) meet with the external auditors prior to the audit to review the planning and staffing of the audit;

g)

receive and review annually the external auditors' written report on their own internal quality control procedures; any material issues raised by the most recent internal quality control review, or peer review, of the external auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, and any steps taken to deal with such issues;

h)

review and evaluate the external auditors, including the lead partner of the external auditor team;

i)

ensure the rotation of the lead (or coordinating) audit partner having primary responsibility for the audit and the audit partner responsible for reviewing the audit as required by law;

VI.

Oversight in Respect of Audit and Non-Audit Services

a)

pre-approve all audit services (which may entail providing comfort letters in connection with securities underwritings) and all permitted non-audit services, other than non-audit services where:

i)

the aggregate amount of all such non-audit services provided to the Company constitutes not more than 5% of the total fees paid by the Company and its subsidiaries to the external auditor during the fiscal year in which the non-audit services are provided;

ii)

such services were not recognized by the Company at the time of the engagement to be non-audit services; and

iii)

such services are promptly brought to the attention of the Audit Committee and approved prior to the completion of the audit by the Audit Committee or by one or more members of the Audit Committee to whom authority to grant such approvals has been delegated by the Audit Committee;

b)

approval by the Audit Committee of a non-audit service to be performed by the external auditor shall be disclosed as required under securities laws and regulations;

c)

the Audit Committee may delegate to one or more designated members of the Audit Committee the authority to grant pre-approvals required by this subsection. The decisions of any member to whom authority is delegated to pre-approve an activity shall be presented to the Audit Committee at its first scheduled meeting following such pre-approval;

d)

if the Audit Committee approves an audit service within the scope of the engagement of the external auditor, such audit service shall be deemed to have been pre-approved for purposes of this subsection;

VII.

Oversight in Respect of Certain Policies

a)

review and recommend to the Board for approval policy changes and program initiatives deemed advisable by management or the Audit Committee with respect to the Company's codes of business conduct and ethics;

b)

obtain reports from management, the Company's senior internal auditing executive and the external auditors and report to the Board on the status and adequacy of the Company's efforts to ensure its businesses are conducted and its facilities are operated in an ethical, legally compliant and socially responsible manner, in accordance with the Company's codes of business conduct and ethics;

c)

establish a non-traceable, confidential and anonymous system by which callers may ask for advice or report any ethical or financial concern, ensure that procedures for the receipt, retention and treatment of complaints in respect of accounting, internal controls and auditing matters are in place, and receive reports on such matters as necessary;

d)

annually review and assess the adequacy of the Company's public disclosure policy;

e)

review and approve the Company's hiring policies for employees or former employees of the external auditors (recognizing the Sarbanes-Oxley Act of 2002 does not permit the CEO, controller, CFO or chief

accounting officer to have participated in the Company's audit as an employee of the external auditors' during the preceding one-year period) and monitor the Company's adherence to the policy;

VIII.

Oversight in Respect of Pension Matters

a)

consider and in accordance with regulatory requirements approve any changes in the Company's pension plans having to do with financial matters after consultation with the Human Resources Audit Committee in respect of any effect such a change may have on pension benefits;

b)

review and consider financial and investment reports relating to the Company's pension plans;

c)

appoint and terminate the engagement of investment managers with respect to the Company's pension plans;

d)

receive, review and report to the Board on the actuarial valuation and funding requirements for the Company's pension plans;

IX.

Oversight in Respect of Internal Administration

a)

review annually the reports of the Company's representatives on certain audit committees of subsidiaries and affiliates of the Company and any significant issues and auditor recommendations concerning such subsidiaries and affiliates;

b)

review the succession plans in respect of the Chief Financial Officer, the Vice President, Risk Management and the Director, Internal Audit;

c)

review and approve guidelines for the Company's hiring of employees or former employees of the external auditors who were engaged on the Company's account;

X.

Oversight Function

While the Audit Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Audit Committee to plan or conduct audits or to determine that the Company's financial statements and disclosures are complete and accurate or are in accordance with generally accepted accounting principles and applicable rules and regulations. These are the responsibilities of management and the external auditors. The Audit Committee, its Chair and any of its members who have accounting or related financial management experience or expertise, are members of the Board, appointed to the Audit Committee to provide broad oversight of the financial disclosure, financial risk and control related activities of the Company, and are specifically not accountable nor responsible for the day to day operation of such activities. Although designation of a member or members as an "audit committee financial expert" is based on that individual's education and experience, which that individual will bring to bear in carrying out his or her duties on the Audit Committee, designation as an "audit committee financial expert" does not impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the Audit Committee and Board in the absence of such designation. Rather, the role of any audit committee financial expert, like the role of all Audit Committee members, is to oversee the process and not to certify or guarantee the internal or external audit of the Company's financial information or public disclosure.

3. Composition of Audit Committee

The Audit Committee shall consist of three or more Directors, a majority of whom are resident Canadians (as defined in the Canada Business Corporations Act), and all of whom are unrelated and/or independent for the purposes of applicable Canadian and United States securities law and applicable rules of any stock exchange on which the Company's shares are listed. Each member of the Audit Committee shall be financially literate and at least one member shall have accounting or related financial management expertise

(as those terms are defined from time to time under the requirements or guidelines for audit committee service under securities laws and the

applicable rules of any stock exchange on which the Company's securities are listed for trading or, if it is not so defined as that term is interpreted by the Board in its business judgment).

4. Appointment of Audit Committee Members

The members of the Audit Committee shall be appointed by the Board from time to time, on the recommendation of the Governance Committee and shall hold office until the next annual meeting of shareholders or until their successors are earlier appointed or until they cease to be Directors of the Company.

5. Vacancies

Where a vacancy occurs at any time in the membership of the Audit Committee, it may be filled by the Board on the recommendation of the Governance Committee.

6. Audit Committee Chair

The Board shall appoint a Chair of the Audit Committee who shall:

a) review and approve the agenda for each meeting of the Audit Committee and as appropriate, consult with members of management;

b) preside over meetings of the Audit Committee;

c) report to the Board on the activities of the Audit Committee relative to its recommendations, resolutions, actions and concerns; and

d) meet as necessary with the internal and external auditors.

7. Absence of Audit Committee Chair

If the Chair of the Audit Committee is not present at any meeting of the Audit Committee, one of the other members of the Audit Committee present at the meeting shall be chosen by the Audit Committee to preside at the meeting.

8. Secretary of Audit Committee

The Corporate Secretary shall act as Secretary to the Audit Committee.

9. Meetings

The Chair, or any two members of the Audit Committee, or the internal auditor, or the external auditors, may call a meeting of the Audit Committee. The Audit Committee shall meet at least quarterly. The Audit Committee shall meet periodically with management, the internal auditors and the external auditors in separate executive sessions.

10. Quorum

A majority of the members of the Audit Committee, present in person or by telephone or other telecommunication device that permit all persons participating in the meeting to speak to each other, shall constitute a quorum.

11. Notice of Meetings

Notice of the time and place of every meeting shall be given in writing or facsimile communication to each member of the Audit Committee at least 24 hours prior to the time fixed for such meeting; provided, however, that a member may in any manner waive a notice of a meeting. Attendance of a member at a meeting is a waiver of notice of the meeting, except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting is not lawfully called.

12. Attendance of Company Officers and Employees at Meeting

At the invitation of the Chair of the Audit Committee, one or more officers or employees of the Company may attend any meeting of the Audit Committee.

13. Procedure, Records and Reporting

The Audit Committee shall fix its own procedure at meetings, keep records of its proceedings and report to the Board when the Audit Committee may deem appropriate but not later than the next meeting of the Board.

14. Review of Charter and Evaluation of Audit Committee

The Audit Committee shall review its Charter annually or otherwise, as it deems appropriate, and if necessary propose changes to the Governance Committee and the Board. The Audit Committee shall annually review the Audit Committee's own performance.

15. Outside Experts and Advisors

The Audit Committee is authorized, when deemed necessary or desirable, to retain independent counsel, outside experts and other advisors, at the Company's expense, to advise the Audit Committee or its members independently on any matter.

16. Reliance

Absent actual knowledge to the contrary (which shall be promptly reported to the Board), each member of the Audit Committee shall be entitled to rely on (i) the integrity of those persons or organizations within and outside the Company from which it receives information, (ii) the accuracy of the financial and other information provided to the Audit Committee by such persons or organizations and (iii) representations made by Management and the external auditors, as to any information technology, internal audit and other non-audit services provided by the external auditors to the Company and its subsidiaries.

SCHEDULE "C"
CHARTER OF
THE GOVERNANCE COMMITTEE

1. Purpose

The Governance Committee is responsible for performing the duties delegated to it by the Board of Directors to enable the Board to fulfill its responsibilities in relation to:

a) maintaining and enhancing the Company's corporate governance practices;

b) identifying and recommending to the Board, selection criteria and qualified individuals in respect of the composition of the Board and its committees; and

c) assessing the performance of the Board, individual members of the Board, committees and the Chair of the Board.

2. Roles and Responsibilities

The Governance Committee shall monitor, review, develop policies, recommend and take other action as appropriate in fulfilling its purpose, including:

I. Corporate Governance

a) recommend and report to the Board on corporate governance issues, principles and guidelines for review, discussion, approval or other action by the Board;

b) review the Company's governance disclosure as may be required by relevant regulatory authorities or stock exchanges, before such disclosure is submitted to the Board;

c) monitor best governance practices and annually review the Company's governance practices with a view to maintaining high standards of corporate governance;

d) ensure that any issues of corporate governance identified by Board members are raised to management of the Company;

e) review the Company's structures and procedures to ensure that the Board is able to and in fact is, functioning independently of management;

II. Boards and Committees

a) review at least annually, the size, composition and profile of the members of the Board and identify and recommend to the Board, appropriate selection criteria for selecting new directors which relate to experience, integrity, competence, skills, knowledge, diversity and dedication;

b) identify and recommend, to the Board, qualified individuals for election or appointment to the Board;

c)

consider and recommend candidates to act as Chair of the Board, for approval by the Board of Directors;

d) recommend members for appointment to committees taking into account the needs of individual committees, committee and board succession planning and opportunities and risks facing the Company;

e) review and recommend changes in the size, composition and charters of the committees of the Board;

f) satisfy itself that there is a satisfactory orientation program for new directors and committee members;

g) provide continuing education opportunities for all directors;

h) view, from time to time, events or matters that would trigger the resignation or retirement of Board members such as, age, changes in principal occupation and other relevant circumstances;

III.

Operation of Board

a) monitor the quality of the relationship between management and the Board and recommend improvements as deemed necessary or desirable;

b) review any surveys completed by directors dealing with the operational effectiveness of the Board;

c) assess the availability, relevance and timeliness of information required by the Board;

IV.

Assessment

a) develop and recommend to the Board, a process for assessing the performance and operation of the Board and its committees, the chair of the Board and each committee as well as for individual Board members;

b) review annually the performance and contribution of individual Board members, including an evaluation of the competencies and skills the Board as a whole should possess;

c) oversee the implementation of assessment processes and report the results and findings of assessments to the Board;

V.

Director Compensation and Shareholder Alignment

a) conduct an annual review of Directors' compensation for Board and Committee service taking into account such criteria as time commitment, compensation provided by comparative companies, responsibilities, and recommend any change for Board approval;

b) monitor compliance with the share ownership policy for directors and senior officers;

c) administer the Deferred Share Unit Plan for non-employee directors; and

d) consider and recommend to the Board, share ownership targets for directors and senior executive officers.

3. Composition of Committee

The Governance Committee shall consist of three or more Directors. In addition, each member of the Governance Committee shall be "independent" for the purposes of applicable Canadian and United States securities law and applicable rules of any exchange on which the Company's shares are listed.

4. Appointment of Committee Members

Members of the Governance Committee shall be appointed by the Board from time to time, and shall hold office until the next annual meeting of shareholders or until their successors are earlier appointed or until they cease to be Directors of the Company.

5. Vacancies

Where a vacancy occurs at any time in the membership of the Governance Committee, it may be filled by the Board on the recommendation of the Governance Committee.

6. Committee Chair

The Board shall appoint a Chair of the Governance Committee who shall:

a) review and approve the agenda for each meeting of the Governance Committee and as appropriate, consult with members of management;

b) preside over meetings of the Governance Committee;

c) report to the Board on the activities of the Governance Committee relative to its recommendations, resolutions, actions and concerns;

d) annually review the performance of the Chair of the Board on input from the members of the Board; and

e) as necessary, review reports on the exercise, acquisition and disposition of share and option holdings by members of senior management.

7. Absence of Committee Chair

If the Chair of the Governance Committee is not present at any meeting of the Governance Committee, one of the other members of the Governance Committee present at the meeting shall be chosen by the Governance Committee to preside at the meeting.

8. Secretary of Committee

The Corporate Secretary shall act as Secretary to the Governance Committee.

9. Meetings

The Chair, or any two members of the Governance Committee, may call a meeting of the Governance Committee. The Governance Committee shall meet at least semi-annually. The Chair of the Board and the Company's President and Chief Executive Officer may attend all meetings of the Governance Committee. The Governance Committee may also meet in separate executive sessions.

10. Quorum

A majority of the members of the Governance Committee, present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak to each other, shall constitute a quorum.

11. Notice of Meetings

Notice of the time and place of every meeting shall be given in writing or facsimile communication to each member of the Governance Committee at least 24 hours prior to the time fixed for such meeting; provided, however, that a member may in any manner waive a notice of a meeting. Attendance of a member at a meeting is a waiver of notice of the meeting, except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting is not lawfully called.

12. Attendance of Company Officers or Employees at Meeting

At the invitation of the Chair of the Governance Committee, one or more officers or employee of the Company may attend any meeting of the Governance Committee.

13. Procedure, Records and Reporting

The Governance Committee shall fix its own procedure at meetings, keep records of its proceedings and report to the Board not later than the next regularly scheduled meeting of the Board.

14. Review of Charter and Evaluation of Committee

The Governance Committee shall evaluate, on an annual basis, its performance and review its Charter and shall, as it deems appropriate, recommend any changes to the Board for approval.

15. Outside Experts and Advisors

The Governance Committee is authorized when deemed necessary or desirable to retain independent counsel, outside experts and other advisors, at the Company's expense, to advise the Governance Committee or its members independently on any matter.

SCHEDULE "D"
CHARTER OF
THE HEALTH, SAFETY AND ENVIRONMENT COMMITTEE

1. Purpose

The Health, Safety and Environment Committee (the "HS&E Committee") is responsible for the duties delegated to it by the Board of Directors to enable the Board to fulfill its oversight responsibilities in relation to:

a) due diligence in the development and implementation of systems and programs for management of health, safety and environmental matters and to ensure the Company's compliance with applicable laws; and

b) reviewing, reporting and making recommendations to the Board about the Company's policies, standards, practices and performance with respect to its corporate responsibility in relation to health, safety and environment.

2. Roles and Responsibilities

The HS&E Committee shall monitor, review, develop policies, recommend and take other action as appropriate in fulfilling its purpose, including:

a) monitor on a regular basis the existing health, safety and environmental practices and procedures of the Company and its controlled subsidiaries for compliance with applicable legislation, conformity with industry standards, implementation of best practices and prevention or mitigation of losses;

b) consider whether the Company's policies and practices relating to health, safety and environmental matters are being effectively implemented;

c) review and consider reports and recommendations issued by the Company or by an external party relating to health, safety or environmental issues, together with management's response thereto;

d) advise and make recommendations to the Board of Directors as appropriate on matters relating to health, safety and the environment;

e) review and report, as appropriate, to the Board of Directors on the Company's policies and procedures relating to health, safety and the environment and, if appropriate, make recommendations to the Board of Directors;

f) ensure the internal auditor has access to the Chair of the HS&E Committee, the Board and the Chief Executive Officer; and

g) meet separately with the Vice-President, Health, Safety and Environment and report to the Board on such meetings.

3. Composition of Committee

The HS&E Committee shall consist of three or more Directors, a majority of whom shall be independent.

4. Appointment of Committee Members

Members of the HS&E Committee shall be appointed by the Board from time to time, and shall hold office until the next annual meeting, or until their successors are earlier appointed, or until they cease to be Directors of the Company.

5. Vacancies

Where a vacancy occurs at any time in the membership of the HS&E Committee, it may be filled by the Board on the recommendation of the HS&E Committee.

6. Committee Chair

The Board shall appoint a Chair for the HS&E Committee who shall:

a) review and approve the agenda for each meeting of the HS&E Committee and as appropriate, consult with members of management;

b) preside over meetings of the HS&E Committee; and

c) report to the Board on the activities of the HS&E Committee relative to its recommendations, resolutions, actions and concerns.

7. Absence of Committee Chair

If the Chair of the HS&E Committee is not present at any meeting of the HS&E Committee, one of the other members of the HS&E Committee present at the meeting shall be chosen by the HS&E Committee to preside at the meeting.

8. Secretary of Committee

The Corporate Secretary shall act as Secretary to the HS&E Committee.

9. Meetings

The Chair, or any two members of the HS&E Committee, or the external auditors, may call a meeting of the HS&E Committee. The HS&E Committee shall meet at least three times per year. The HS&E Committee may also meet periodically in separate executive sessions.

10. Quorum

A majority of the members of the HS&E Committee, present in person or by telephone or other telecommunication device that permit all persons participating in the meeting to speak to each other, shall constitute a quorum.

11. Notice of Meetings

Notice of the time and place of every meeting shall be given in writing or facsimile communication to each member of the HS&E Committee at least 24 hours prior to the time fixed for such meeting; provided, however, that a member may in any manner waive a notice of a meeting. Attendance of a member at a meeting is a waiver of notice of the meeting, except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting is not lawfully called.

12. Attendance of Company Officers and Employees at Meeting

At the invitation of the Chair of the HS&E Committee, one or more officers or employees of the Company may attend any meeting of the HS&E Committee.

13. Procedure, Records and Reporting

The HS&E Committee shall fix its own procedure at meetings, keep records of its proceedings and report to the Board when the HS&E Committee may deem appropriate but not later than the next regularly scheduled meeting of the Board.

14. Review of Charter and Evaluation of Committee

The HS&E Committee shall evaluate, on an annual basis, its performance and review its Charter and shall, as it deems appropriate, recommend any changes to the HS&E Committee and the Board for approval.

15. Outside Experts and Advisors

The HS&E Committee is authorized, when deemed necessary or desirable, to retain independent counsel, outside experts and other advisors, at the Company's expense, to advise the HS&E Committee or its members independently on any matter.

SCHEDULE "E"
CHARTER OF
THE HUMAN RESOURCES COMMITTEE

1. Purpose

The Human Resources Committee is responsible for performing the duties delegated to it by the Board of Directors to enable the Board to fulfill its responsibilities in relation to:

a) approving goals and objectives, and performance against these goals and objectives, for the President and Chief Executive Officer, and recommending to the Board all Chief Executive Officer compensation matters (including retirement arrangements);

b) reviewing and approving total compensation (including retirement arrangements) for the senior executive officers; and

c) reviewing and approving the Company's human resources philosophies, policies, succession plans and compensation and benefits plans as they pertain to the Company's corporate strategy.

2. Roles and Responsibilities

The Human Resources Committee shall monitor, review, approve, recommend and take other action as appropriate in fulfilling its purpose, including:

a) review and recommend to the Board, goals and objectives relevant to the President and Chief Executive Officer's compensation and conduct an annual review and assessment of the performance against these goals and objectives of the President and Chief Executive Officer, and review annually, the performance of the senior executive officers of the Company;

b) consider and approve the salary and other remuneration, to be awarded to senior executive officers of the Company and make recommendations to the Board on the remuneration package for the President and Chief Executive Officer;

c) review and approve any agreements with senior executive officers with respect to compensation, benefits, or termination arrangements and oversee administration of any such agreements as required;

d) review with the President and Chief Executive Officer existing management resources and plans, including recruitment and training programs, for ensuring that qualified personnel will be available for succession to senior executive officer positions in the Company, and report on this matter to the Board at least once each year;

e) consider, with the President and Chief Executive Officer, proposed changes in organization or personnel affecting the senior executive officers group and recommend for approval any change requiring Board action;

f) approve and review with the President and Chief Executive Officer the Company's overall compensation philosophy and compensation and benefits plans in relation to the Company's business strategy;

g) subject to any specific responsibilities as set out in this Charter, consider and approve changes in the Company's compensation and benefit plans involving an annual change in cost to the Company in excess of $10 million;

h)

consider and approve any major benefit changes in the Company's pension plans (after consultation with the Audit Committee) in respect of any significant effect such a change may have on pension financial matters; appoint members to the Company's Pension Committee, and report thereon to the Board;

i) consider and approve the Company's equity based compensation programs, (collectively referred to as the "Equity Plans"), in accordance with the requisite plan texts and relevant legislation, and do such other things including the following:

1. review the initial design, development and plan texts of Equity Plans, and recommend to the Board the adoption or creation of any such Equity Plans;

2. approve the designation of employees who are to participate in the Equity Plans;

3. approve grants for each participant and any applicable terms and conditions pursuant to the plan texts of such grants including but not limited to: term, price, vesting, and performance requirements;

4. interpret any Equity Plans' texts as required from time to time, including (upon consultation with the Audit Committee) the determination of the degree to which performance requirements have been met;

5. review and monitor the entire equity grant funding and effect this has on dilution and overall corporate expense;

6. consider and recommend to the Board any requirement for shares to be set aside from the authorized and unissued shares of the Company; and

7. approve and recommend to the Board any significant amendments to the Equity Plans or the discontinuance or substitution thereof;

j) consider and approve the Company's non-equity based incentive compensation programs, (collectively referred to as the "Non-Equity Programs"), in accordance with the requisite plan texts and applicable legislation, and do such other things including the following:

1. approve the initial design, development and any plan texts of Non-Equity Programs;

2. approve overall Company grants, including individual grants to senior executive officers, and any applicable terms and conditions pursuant to the plan texts of such grants including but not limited to: term, price, vesting, estimated cost and performance requirements;

3. interpret any Non-Equity Programs' texts as required from time to time, including (upon consultation with the Audit Committee) the determination of the degree to which performance requirements have been met; and

4. approve any significant amendments to the Non Equity Programs or the discontinuance or substitution thereof;

k) review and approve the annual report on executive compensation for inclusion in the Company's public disclosure documents; and

l) discharge any other responsibilities allocated to the Committee by the Board.

3. Composition of Committee

The Human Resources Committee shall consist of three or more Directors. In addition, each member of the Human Resources Committee shall be "independent" for the purposes of applicable Canadian and United States securities law and applicable rules of any exchange on which the Company's shares are listed.

4. Appointment of Committee Members

Members of the Human Resources Committee shall be appointed by the Board from time to time, and shall hold office until the next annual meeting, or until their successors are earlier appointed, or until they cease to be Directors of the Company.

5. Vacancies

Where a vacancy occurs at any time in the membership of the Human Resources Committee, it may be filled by the Board on the recommendation of the Human Resources Committee.

6. Committee Chair

The Board shall appoint a Chair for the Human Resources Committee who shall:

a) review and approve the agenda for each meeting of the Human Resources Committee and as appropriate, consult with members of management;

b) preside over meetings of the Human Resources Committee;

c) report to the Board on the activities of the Human Resources Committee relative to its recommendations, resolutions, actions and concerns; and

d) obtain and maintain relationships with independent advisors including consultants, lawyers and other professionals when deemed necessary or advisable.

7. Absence of Committee Chair

If the Chair of the Human Resources Committee is not present at any meeting of the Human Resources Committee, one of the other members of the Human Resources Committee present at the meeting shall be chosen by the Human Resources Committee to preside at the meeting.

8. Secretary of Committee

The Corporate Secretary shall act as Secretary to the Human Resources Committee.

9. Meetings

The Chair, or any two members of the Human Resources Committee, or the external auditors, may call a meeting of the Human Resources Committee. The Human Resources Committee shall meet at least three times per year. The Human Resources Committee may also meet periodically in separate executive sessions.

10. Quorum

A majority of the members of the Human Resources Committee, present in person or by telephone or other telecommunication device that permit all persons participating in the meeting to speak to each other, shall constitute a quorum.

11. Notice of Meetings

Notice of the time and place of every meeting shall be given in writing or facsimile communication to each member of the Human Resources Committee at least 24 hours prior to the time fixed for such meeting; provided, however, that a member may in any manner waive a notice of a meeting. Attendance of a member at a meeting is a waiver of notice of the meeting, except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting is not lawfully called.

12. Attendance of Company Officers and Employees at Meeting

At the invitation of the Chair of the Human Resources Committee, one or more officers or employees of the Company may attend any meeting of the Human Resources Committee.

13. Procedure, Records and Reporting

The Human Resources Committee shall fix its own procedure at meetings, keep records of its proceedings and report to the Board when the Human Resources Committee may deem appropriate but not later than the next regularly scheduled meeting of the Board.

14. Review of Charter and Evaluation of Committee

The Human Resources Committee shall evaluate, on an annual basis, its performance and review its Charter and shall, as it deems appropriate, recommend any changes to the Human Resources Committee and the Board for approval.

15. Outside Experts and Advisors

The Human Resources Committee is authorized, when deemed necessary or desirable, to retain independent counsel, outside experts and other advisors, at the Company's expense, to advise the Human Resources Committee or its members independently on any matter.

Financial Highlights

Year ended December 31 (millions of dollars)	**2005**	2004	2003	2002	2001	2000
Income Statement						
Net income/(loss)						
Continuing operations	**1,209**	980	801	747	686	628
Discontinued operations		52	50		(67)	61
	1,209	1,032	851	747	619	689
Cash Flow Statement						
Funds generated from operations	**1,951**	1,703	1,822	1,843	1,625	1,484
(Increase)/decrease in operating working capital	**(49)**	29	93	92	(487)	437
Net cash provided by operations	**1,902**	1,732	1,915	1,935	1,138	1,921
Capital expenditures and acquisitions	**2,071**	2,046	965	851	1,082	1,144
Balance Sheet						
Total assets	**24,113**	22,422	20,887	20,555	20,531	25,245

Long-term debt	**9,640**	9,749	9,516	8,899	9,444	10,008
Common shareholders' equity	**7,206**	6,565	6,091	5,747	5,426	5,211

Common Share Statistics *Year ended December 31*	**2005**	2004	2003	2002	2001	2000
Net income/(loss) per share Basic						
Continuing operations	**$2.49**	$2.02	$1.66	$1.56	$1.44	$1.32
Discontinued operations		0.11	0.10		(0.14)	0.13
	$2.49	$2.13	$1.76	$1.56	$1.30	$1.45
Net income/(loss) per share Diluted						
Continuing operations	**$2.47**	$2.01	$1.66	$1.55	$1.44	$1.32
Discontinued operations		0.11	0.10		(0.14)	0.13
	$2.47	$2.12	$1.76	$1.55	$1.30	$1.45
Dividends declared per share	**$1.22**	$1.16	$1.08	$1.00	$0.90	$0.80
Common shares outstanding (millions)						
Average for the year	**486.2**	484.1	481.5	478.3	475.8	474.6
End of year	**487.2**	484.9	483.2	479.5	476.6	474.9

Chairman's Message

TransCanada has in place the key building blocks of a truly great company the right team, the right businesses and the right strategy.

TransCanada continues to make great strides in achieving its goal of becoming the leading North American energy infrastructure company. The company's financial strength and focused execution in 2005 delivered excellent results and consequently we were able to increase the dividend in January 2006 for the sixth consecutive year.

Our Board was again honoured this past year to be recognized as one of Canada's top corporate boards. It is a privilege to work with such a highly respected group. The commitment to meeting the highest standards of integrity and governance best practices is unquestioned, but a key focus remains on what we strongly believe is the most important role of the Board making the strategic decisions that are in the best interests of shareholders and other stakeholders. Our primary responsibility is to foster the long-term success of the company and a cornerstone of that responsibility is the Board's active role in the discussion, refinement and approval of the company's strategic activities.

That kind of strategic leadership is exemplified by Doug Baldwin, a director who will retire from the Board at the Annual Meeting in April 2006. As a director since 1999, and as President and Chief Executive Officer from August 1999 to April 2001, Mr. Baldwin played a pivotal role in bringing TransCanada to where it is today.

We also thank Tom Stephens, who stepped down from the Board in 2005, for his valued contribution and dedicated service.

Three new directors joined the Board over the last year, their backgrounds reflecting TransCanada's growing presence in the North American energy market. Mr. Kevin E. Benson, President and Chief Executive Officer, Laidlaw International, Inc. contributes significant financial and business leadership. Dr. E. Linn Draper, Former Chairman, President and Chief Executive Officer, American Electric Power Co., Inc., brings tremendous knowledge of and insight into U.S. energy markets and nuclear power. Mr. Derek H. Burney, O.C., Chairman of the Board, New Brunswick Power, offers unique experience in federal government and Canada-U.S. relations. All three are valuable additions to an already strong and representative Board.

Looking forward, the Board is pleased to approve the nomination of D. Michael G. Stewart, Principal, Ballinacurra Group, to the Board at our annual meeting in April. Mr. Stewart brings a wealth of experience in the oil and gas and utility industries.

Along with the Board, I would express our appreciation to the management and the employees of TransCanada for their commitment and exceptional performance over the past year and for continuing to exemplify TransCanada's core values of integrity, trust and respect. The combination of this excellent team, our strong and growing core businesses, and a proven strategy makes TransCanada a company in which we can all take great pride.

On behalf of the Board of Directors,

S. Barry Jackson
Chair

Letter to Shareholders

Six years ago, we took the strategic decision to focus on our core businesses of natural gas transmission and power. Our strategies then, and now, are to grow those businesses, to maximize the long-term value of our existing assets, to focus on operational excellence and to enhance our corporate strength and competitive position within North America. As we begin 2006, we can confidently say the growth strategies we embraced six years ago have proven successful.

Delivering value for our shareholders Net income from continuing operations (net earnings) grew to a record $1.209 billion or $2.49 per share in 2005. Excluding gains on sale of TransCanada Power, L.P., units of TC PipeLines, LP and P.T. Paiton Energy Company, net earnings were $852 million or $1.75 per share.

Funds generated from operations were approximately $2.0 billion. This strong underlying cash flow, combined with proceeds from the sale of non-core assets, allowed us to invest approximately $2.1 billion in our core businesses of natural gas transmission and power. As in previous years, we were able to make those investments without issuing common equity or weakening our financial position.

During 2005, the Board of Directors increased the annual dividend on the company's common shares from $1.16 to $1.22 and our share value increased from $29.80 at the end of 2004 to $36.65 at December 31, 2005. Total shareholder return in 2005 was approximately 28 per cent.

In January 2006, TransCanada's Board of Directors raised the quarterly dividend on the company's common shares to $0.32 per share, which is equivalent, on an annualized basis, to $1.28 per share.

Since 2000, dividends per common share have grown from 80 cents to $1.28, an increase of eight per cent per year.

Building on a solid track record The results we achieved in 2005 build on the track record of success we have established since 1999 and are driven by the diligent and disciplined execution of our growth strategies.

During the past six years:

- Net income per share from continuing operations, excluding gains, has grown from $1.08 to $1.75, an increase of eight per cent per year
- Funds generated from operations have grown from approximately $1.0 billion to approximately $2.0 billion, an increase of 11 per cent per year
- Total shareholder return has averaged 25 per cent per year

For a company the size of TransCanada, it takes substantial investment to deliver measurable growth in earnings. Since 1999, we've invested more than $8.5 billion in our core businesses. Notably, we could have invested more. However, we are determined to stay within our strategic parameters and to evaluate opportunities rigorously. We pursue only those acquisitions and development projects that make sense for TransCanada, that deliver benefits to our shareholders and other stakeholders, and that offer potential for future growth.

Growing our Pipeline Business

Strategic acquisitions and expansions In our natural gas transmission business, we are focused on growing our system to offer our customers unparalleled connections from traditional and emerging supply basins to key North American markets. No other company shares TransCanada's market reach. We continue to extend our presence through acquisitions including the Gas Transmisssion Northwest System and North Baja System in the western United States that deliver natural gas into the California and Mexico markets and over time, will connect us to new and proposed liquefied natural gas (LNG) terminals on the west coast of Mexico.

We've also increased our ownership interests in strategically significant pipeline systems such as Foothills, which forms the "pre-build" portion of the proposed Alaska Highway Pipeline Project, Iroquois Gas Transmission which serves the high-demand market of New York City, and Portland Natural Gas Transmission, which delivers natural gas to growing markets in New England. In February 2006, through TC PipeLines, LP, we entered into agreements which increase our interest in Northern Border Pipeline, the largest natural gas pipeline serving the U.S. Midwest. In early 2007, TransCanada will become the operator of this pipeline that annually transports more than 20 per cent of the natural gas exported from Canada to the U.S. and is positioned to play a significant role in delivering northern natural gas to market.

Northern development We remain active in the advancement of the Mackenzie Gas and Alaska Highway pipeline projects to bring much-needed northern natural gas to market. We were pleased to see the Mackenzie Gas Pipeline Project move to hearings before the National Energy Board in January 2006 and to participate in the hearings of the Joint Review Panel the following month. With respect to Alaska, we remain encouraged by the process that has unfolded between the Alaska North Slope Producers and the State of Alaska during recent months, and await its substantive conclusion. TransCanada, as the holder of the Canadian rights under the Northern Pipeline Act (NPA), is ready to work with North Slope producers to complete the Canadian section of an Alaska Highway pipeline and assist where possible with the project within Alaska.

Mexico Further south, we've set our sights on opportunities in Mexico. In 2005, we began construction on the 125 kilometre Tamazunchale Pipeline in Mexico. We view Mexico as an integral component of the broader North American natural gas market, and anticipate future growth through the development of new natural gas pipelines and LNG terminals.

Growing Power

Exponential growth In Power, since 1999, we've grown our portfolio of generating capacity by approximately thirteen times to more than 6,700 megawatts (MW) at the start of 2006. In doing so, we've built a diversified portfolio of low-cost, base-load power generation in selected markets where we enjoy competitive advantage. Notable investments over the past six years include our interest in Bruce Power, one of Ontario's largest independent power generators. In 2005, Bruce Power initiated a restart and refurbishment program for the Bruce A units, which will bring Bruce Power's total generating capacity to 6,200 MW. TransCanada will invest approximately $2.125 billion in the restart program through 2011.

Value-creating acquisitions In April 2005, we acquired hydroelectric generation assets in New England with 567 MW of capacity. These are low-cost, base-load facilities that fit well with our existing operations in the Northeastern U.S. The acquisition was immediately accretive to earnings and cash flow.

In December 2005, TransCanada acquired the remaining rights and obligations of the 756 MW Sheerness Power Purchase Arrangement (PPA). This acquisition adds to the Sundance A and B PPAs we acquired in 2001 and 2002, respectively, providing the company with additional low-cost, base-load power and further expanding and diversifying our power business in Alberta.

Partner of choice We've continued to build our profile as a partner of choice in the development of efficient and environmentally responsible cogeneration plants. Since 1999, we've built six cogeneration plants, including the 90 MW Grandview plant in New Brunswick, which was commissioned in January 2005. Over the course of the year, TransCanada continued construction of the 550 MW Bécancour plant our largest cogeneration plant to date and we're on track to bring the plant into commercial service in late 2006.

Wind energy With wind power becoming increasingly viable from an economic and technological standpoint, TransCanada is positioned to become one of North America's largest providers of wind energy through our 62 per cent interest in Cartier Wind Energy Inc. Cartier Wind was awarded six projects by Hydro-Québec Distribution representing a total of 739.5 MW. Construction is scheduled to begin in early 2006. The first wind farm is anticipated to be operational beginning in late 2006 with the remaining projects continuing through 2012.

New Opportunities

Oil transmission TransCanada is in the business of connecting energy supplies to markets. During the past year, we've made significant progress on the Keystone crude oil pipeline project a US$2.1 billion, 2,960 kilometre pipeline that combines new build in the U.S., Alberta and Manitoba with the conversion of a portion of TransCanada's existing pipeline facilities from natural gas to crude oil transmission in Canada. The pipeline would initially be capable of shipping 435,000 barrels per day of crude oil from Alberta to markets in the U.S. Midwest and could be expanded to 590,000 barrels per day with additional pump stations.

TransCanada has secured firm, long-term shipping commitments on the proposed Keystone pipeline totalling approximately 340,000 barrels per day, with a duration averaging 18 years. This commercial support, including a significant commitment from ConocoPhillips Company, confirms that our project is an innovative and cost-competitive way to link rising oil sands production to preferred markets in the U.S. Midwest.

Natural Gas Storage In 2005, we initiated construction of our Edson natural gas storage facility in Alberta and anticipate beginning to offer storage capacity on a phased-in basis in mid-2006. With capacity of 60 petajoules, the Edson facility, combined with storage capacity that we own through CrossAlta Gas Storage & Services and lease of storage capacity through a third party, will position TransCanada to become one of the largest natural gas storage providers in Western Canada. We believe Alberta-based natural gas storage will continue to serve market needs and will play an important role in the connection of northern natural gas to North American markets. We see natural gas storage as a natural extension to our gas transmission business.

LNG We continue to pursue the construction and operation of LNG terminals in Québec and New York.

In February 2006, Québec's Ministry of Environment notified TransCanada it will begin its public consultation period allowing the next phase for the proposed Cacouna Energy LNG terminal to begin. In September 2005, residents from the village of Cacouna, Québec gave the Cacouna Energy project a vote of confidence in a town referendum with approximately 57 per cent of voters supporting the proposed development of an LNG facility near the town, which is located near Rivière-du-Loup. The Cacouna Energy project, a partnership between TransCanada and Petro-Canada, would be capable of receiving, storing, and regasifying imported LNG with an average send-out capacity of approximately 500 million cubic feet per day of natural gas.

In January 2006, Broadwater Energy filed its formal application with the U.S. Federal Energy Regulatory Commission for approval to construct and operate the Broadwater LNG project in Long Island Sound. Broadwater plans to begin operation in late 2010 supplying one billion cubic feet of natural gas per day, an amount equal to the needs of four million New York and Connecticut residences. Broadwater is being developed jointly by TransCanada and Shell US Gas & Power LLC, the world's leading LNG player.

Future opportunities The need for new natural gas and power infrastructure is becoming critical in many parts of North America. Existing systems have delivered more and more natural gas and power to growing markets over many years, and many of those systems have now reached their limits. Deregulation has made it more difficult to undertake large and complex infrastructure projects, while complex regulatory processes have delayed the construction of new and essential infrastructure. North America is facing an "infrastructure deficit" that must be addressed in the near to medium term.

North America's infrastructure challenge creates significant opportunities for companies like TransCanada. With more than 50 years experience in the planning, construction and operation of large-scale infrastructure, TransCanada plays a vital role in the North American energy market. As new sources of supply are developed from northern gas, LNG and oil sands to power generated by wind, nuclear, clean coal and natural gas the growth initiatives we've embarked on over the last six years position TransCanada to play a key role in connecting new supplies with ever-growing demand in our preferred North American markets.

The development of future opportunities is a strategic priority at TransCanada. Over the past six years we have studied the energy markets of North America from an infrastructure perspective. We have identified market regions that will need new infrastructure, and we have identified sources of natural gas and electricity that could meet the demands of growing market regions. We have acquired key assets upon which we can build, such as the Gas Transmission Northwest System, Bruce Power and the Foothills System. We have developed new projects that are now under construction, including Bécancour, Cartier Wind, Edson gas storage, the Tamazunchale Pipeline and the Bruce A restart. We have created new projects that are moving towards construction, including Keystone, North Baja and our two LNG projects at Cacouna and Broadwater. At all times we have focused on our core regions and relied on our genuine competitive advantages.

The cycle of opportunity generation, business development and project implementation is essential to the long-term future of our company. We will continue to analyze, develop and expand our portfolio of attractive capital projects, to ensure that TransCanada is well positioned to create significant shareholder value for many years to come.

Pipe, power and people We would not have this wonderful growth story to tell without the hard work and dedication of TransCanada's people. The TransCanada team is highly competent, energized, motivated and committed to the objectives and priorities of the company. Our success over the past six years is testament to their efforts.

In Closing I wish to acknowledge the exceptional contributions of Doug Baldwin who will retire from TransCanada's Board of Directors in April 2006.

Mr. Baldwin stepped forward to serve as TransCanada's Chief Executive Officer from August 1999 to April 2001. Under Doug's leadership, the new TransCanada emerged a strong, Calgary-based enterprise engaged in natural gas transmission and power generation with a strong focus on blue-chip opportunities in Canada and the northern United States. TransCanada has evolved and we have broadened our focus over the five years since Doug retired as CEO, but we have not strayed from the key strategies that were developed in his tenure.

On behalf of TransCanada's employees, I express our sincere thanks to Doug Baldwin for his astute leadership, extraordinary common sense and unwavering commitment to the long-term success of our company. Doug, we wish you the very best.

Hal Kvisle President and Chief Executive Officer

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The Management's Discussion and Analysis (MD&A) dated February 27, 2006 should be read in conjunction with the audited Consolidated Financial Statements of TransCanada Corporation (TransCanada or the company) and the notes thereto for the year ended December 31, 2005. Amounts are stated in Canadian dollars unless otherwise indicated.

CONSOLIDATED FINANCIAL REVIEW

HIGHLIGHTS

Net Income

In 2005, net income was $1,209 million or $2.49 per share compared to $1,032 million or $2.13 per share in 2004.

Net Earnings

In 2005, TransCanada's net income from continuing operations (net earnings) increased $229 million to $1,209 million or $2.49 per share compared to $980 million or $2.02 per share in 2004.

Excluding gains on sale of assets, TransCanada's net earnings increased $66 million to $852 million or $1.75 per share compared to $786 million or $1.62 per share.

Investing Activities

In 2005, TransCanada invested more than $2.0 billion in the Gas Transmission and Power businesses.

Balance Sheet

In 2005, TransCanada's shareholders' equity increased by more than $0.6 billion.

The total market value of the company's common shares at December 31, 2005 was $17.9 billion, an increase of $3.4 billion from December 31, 2004.

Dividend

In January 2006, the Board of Directors of TransCanada raised the quarterly dividend on the company's outstanding common shares five per cent to $0.32 per share from $0.305 per share for the quarter ending March 31, 2006.

CONSOLIDATED RESULTS-AT-A-GLANCE

Year ended December 31 (millions of dollars except per share amounts)

	2005	2004	2003
Net Income			
Continuing operations	**1,209**	980	801
Discontinued operations		52	50
	1,209	1,032	851

Net Income Per Share	**Basic**			
Continuing operations		**$2.49**	$2.02	$1.66
Discontinued operations			0.11	0.10
		$2.49	$2.13	$1.76

SEGMENT RESULTS-AT-A-GLANCE

Year ended December 31 (millions of dollars except per share amounts)

	2005	2004	2003
Gas Transmission Net Earnings			
Excluding gains	**635**	579	622
Gain on sale of PipeLines LP units	**49**		
Gain on sale of Millennium		7	
	684	586	622
Power Net Earnings			
Excluding gains	**253**	209	220
Gain on sale of Paiton Energy	**115**		
Gains related to Power LP	**193**	187	
	561	396	220
Corporate	**(36)**	(2)	(41)
Net Income			
Continuing Operations[1]	**1,209**	980	801
Discontinued Operations		52	50
	1,209	1,032	851
Net Income Per Share Basic			
Continuing Operations[2]	**$2.49**	$2.02	$1.66
Discontinued Operations		0.11	0.10
	$2.49	$2.13	$1.76
[1] **Net Income from Continuing Operations:**			
Excluding gains	**852**	786	801
Gains related to Paiton Energy, PipeLines LP, Power LP and Millennium	**357**	194	
	1,209	980	801
[2] **Net Income Per Share from Continuing Operations:**			
Excluding gains	**$1.75**	$1.62	$1.66
Gains related to Paiton Energy, PipeLines LP, Power LP and Millennium	**0.74**	0.40	
	$2.49	$2.02	$1.66

Net income for the year ended December 31, 2005 was $1,209 million or $2.49 per share compared to $1,032 million or $2.13 per share for 2004 and $851 million or $1.76 per share for 2003. This includes net income from discontinued operations of $52 million or $0.11 per share in 2004 and $50 million or $0.10 per share in 2003, reflecting income recognized on the initially deferred gains relating to the disposition in 2001 of the company's Gas Marketing business.

TransCanada's net earnings for the year ended December 31, 2005 were $1,209 million or $2.49 per share compared to $980 million or $2.02 per share and $801 million or $1.66 per share in 2004 and 2003, respectively. Net earnings for 2005 included after-tax gains of $193 million on the sale of the company's interest in TransCanada Power, L.P. (Power LP), $115 million on the sale of the company's interest in P.T. Paiton Energy Company (Paiton Energy) and $49 million on the sale of TC PipeLines, LP (PipeLines LP) units, while net earnings for 2004 included after-tax gains of $187 million on the sale of the ManChief and Curtis Palmer assets to Power LP and the recognition of dilution gains

resulting from a reduction in TransCanada's ownership interest in Power LP and other previously deferred gains, as well as a $7 million after-tax gain on sale of the company's equity interest in the Millennium Pipeline Project (Millennium).

Excluding the total gains of $357 million recorded in 2005 and total gains of $194 million recorded in 2004, net earnings for 2005 of $852 million or $1.75 per share increased $66 million or $0.13 per share compared to 2004. This was mainly due to an increase in net earnings from the Gas Transmission and Power businesses, partially offset by an increase in net expenses in Corporate.

Excluding the gains on sale of PipeLines LP units in 2005 and the Millennium interest in 2004, the $56 million increase in net earnings from the Gas Transmission business for 2005 compared to 2004 was primarily attributable to a $57 million increase as a result of a full year of net earnings from the Gas Transmission Northwest System and the North Baja System (collectively GTN), acquired on November 1, 2004. In addition, Gas Transmission's net earnings for 2005 included approximately $35 million ($13 million related to 2004 and $22 million related to 2005) as a result of the April 2005 National Energy Board (NEB) decision on the Canadian Mainline's 2004 Tolls and Tariff Application (Phase II). This decision dealt with capital structure and included an increase in the deemed common equity ratio to 36 per cent from 33 per cent for 2004, which was also effective for 2005 under the 2005 tolls settlement. The increase in Canadian Mainline's net earnings for 2005 as a result of this NEB decision was partially offset by a combination of a lower average investment base, lower earnings related to operating cost savings and a decrease in the approved rate of return on common equity (ROE) in 2005 compared to 2004. These increases in net earnings were partially offset by lower net earnings from TransCanada's Other Gas Transmission businesses.

Excluding the gains related to the company's investments in Power LP in 2004 and 2005 and Paiton Energy in 2005, Power's net earnings for 2005 increased $44 million compared to 2004 as a result of higher operating and other income from Bruce Power (being the collective investments in Bruce Power A L.P. (Bruce A) and Bruce Power L.P. (Bruce B)) and Eastern Operations, partially offset by a lower contribution from Western Operations and higher general, administrative, support costs and other.

The increase in net expenses of $34 million in Corporate in 2005 compared to 2004 was primarily due to increased net interest expense on higher average long-term debt and commercial paper balances in 2005 as well as the release in 2004 of previously established restructuring provisions.

The increase in net earnings of $179 million or $0.36 per share in 2004 compared to 2003 included $187 million of gains related to Power LP and a $7 million gain on sale of Millennium. Excluding these gains, 2004 net earnings decreased $15 million from 2003. Lower net earnings in the Gas Transmission and Power businesses were partially offset by reduced net expenses in Corporate. The decrease in net earnings, excluding gains, of $43 million in the Gas Transmission business in 2004 compared to 2003 was primarily due to a decline in the Alberta System's and Canadian Mainline's net earnings. The $11 million decrease in Power's net earnings, excluding gains, in 2004 compared to 2003 was primarily due to a $19 million after-tax settlement with a counterparty in 2003. The decrease in net expenses of $39 million in Corporate in 2004 compared to 2003 was primarily due to the positive impacts of income tax, foreign exchange related items and release of the restructuring provisions in 2004.

FORWARD-LOOKING INFORMATION

Certain information in this MD&A includes forward-looking statements. All forward-looking statements are based on TransCanada's beliefs and assumptions based on information available at the time the assumptions were made. Forward-looking statements relate to, among other things, anticipated financial performance, business prospects, strategies, regulatory developments, new services, market forces, commitments and technological developments. By its nature, such forward-looking information is subject to various risks and uncertainties, including those material risks discussed in this MD&A under "Gas Transmission Business Risks" and "Power Business Risks", which could cause TransCanada's actual results and experience to differ materially from the anticipated results or other expectations expressed. The material assumptions in making these forward-looking statements are disclosed in this MD&A under the headings "Overview and Strategic Priorities", "Gas Transmission Opportunities and Developments", "Gas Transmission

Outlook", "Power Opportunities and Developments" and "Power Outlook". Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this MD&A or otherwise, and TransCanada undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise.

TRANSCANADA OVERVIEW

TransCanada is a leading North American energy infrastructure company with a strong focus on natural gas transmission and power generation opportunities located in regions in which it has significant competitive advantages. Natural gas transmission and power are complementary businesses for TransCanada. They are driven by similar supply and demand fundamentals, they are both capital intensive businesses, and they use similar technology and operating practices. They are also businesses with significant long-term growth prospects.

North American natural gas demand is growing and is mainly driven by the demand for electricity. Experts predict that demand for electricity will increase at an average annual rate of approximately two per cent over the next ten years primarily due to a growing population and an increase in gross domestic product. A large part of this growth is expected to be met through higher utilization of natural gas-fired power generating plants that were built as part of the significant capacity additions that occurred in many North American markets over the last five years.

Nuclear facilities have played, and will continue to play, a significant role in supplying North America with power and new nuclear capacity is expected to come on stream over time. Coal-fired plants remain the largest source of electric power in North America and coal reserves are significant. However, the long lead times required to complete new coal and nuclear projects, the associated environmental and socio-economic issues, the high capital costs and the difficulty in locating these plants near load centres may impede the development and completion of new coal or nuclear generation over the next five to ten years. As a result, North America is expected to continue to rely on natural gas-fired generation to satisfy its growing electricity needs in the near term. This is expected to lead to a significant increase in natural gas consumption. Natural gas demand in North America, including Mexico, is expected to grow to approximately 92 billion cubic feet per day (Bcf/d) by 2015, an increase of 16 Bcf/d when compared to 2005. New natural gas-fired power generation is expected to account for approximately 10 Bcf/d of that growth.

While growing demand will provide a number of opportunities, the natural gas industry also faces a number of challenges. North America has entered a period when it will no longer be able to rely solely on traditional sources of natural gas supply to meet its growing needs. Current high natural gas prices suggest that North America is in a period of transition and significant change. Natural gas supply is tight and this is likely to continue until major investments are made in the infrastructure required to bring new supply to market. Looking forward, production from North America's traditional basins is expected to essentially remain flat over the next decade. An increase in production in the United States Rockies will likely only offset declines in other basins, including the Gulf of Mexico. This outlook for traditional basins means that northern gas and offshore liquefied natural gas (LNG) will be required to fill the expected shortfall between supply and demand. TransCanada is well positioned in North America to serve growing power demand in the near term and to bring new natural gas supplies to market in the medium to longer term.

TRANSCANADA'S STRATEGY

TransCanada's strong position is the direct result of successfully executing its corporate strategy which was first adopted in 2000. While the plan has evolved over time in response to actual and anticipated changes in the business environment, it fundamentally remains the same. Today, TransCanada's corporate strategy consists of the following five components:

Grow the North American Gas Transmission business.

Maximize the long-term value of existing Gas Transmission assets.

Grow the North American Power business.

Drive for operational excellence.

Maximize TransCanada's competitive strength, its opportunities and options, and its enduring value.

Gas Transmission

Strategy

The company's strategy in Gas Transmission is focused on growing its North American business while maximizing the long-term value of its existing natural gas transmission assets. In order to grow the Gas Transmission business, TransCanada is focusing its efforts on expanding and extending its existing systems to connect new supply to growing markets, increasing its ownership in partially-owned entities, acquiring or constructing pipelines that provide it with a significant regional presence, expanding into crude oil transmission and in the long term, connecting new sources of supply in the form of northern natural gas and LNG.

Over the past 50 years, TransCanada has developed significant expertise in large-diameter, cold-climate natural gas pipeline design, construction, operation and maintenance. It has also developed significant expertise in the design, optimization and operation of large gas turbine compressor stations. Today, TransCanada operates one of the largest, most sophisticated, remote-controlled pipeline networks in the world with a solid reputation for safety and reliability. TransCanada also has strong project development and management skills and is committed to the highest levels of operational excellence. The company's strong financial position allows it to build large-scale infrastructure and act quickly on quality opportunities as they arise.

In addition to growing the North American Gas Transmission business, the company continues to place a strategic priority on maximizing the long-term value of its wholly-owned pipelines. Efforts in this area are focused on achieving a fair return on invested capital, developing highly competitive tariff structures, and streamlining and harmonizing processes and tariff provisions for and among TransCanada's regulated pipelines. Further, the company continues to work collaboratively with its customers to develop and implement new services that deliver value to customers while sustaining TransCanada's Gas Transmission business.

Existing Pipelines

TransCanada's natural gas transmission assets link the Western Canada Sedimentary Basin (WCSB) with premium North American markets. With more than 41,000 kilometres (km) of pipeline, the company's wholly-owned gas transmission network is one of the largest in North America.

In 2005, the wholly-owned Alberta System gathered 66 per cent of the natural gas produced in Western Canada, equal to 17 per cent of total North American production. TransCanada exports gas from the WCSB to Eastern Canada as well as the U.S. West, Midwest and Northeast through four wholly-owned pipeline systems:

the Canadian Mainline;

the Gas Transmission Northwest System;

the Foothills System; and

the BC System.

TransCanada also exports gas from the WCSB to Eastern Canada as well as the U.S. West, Midwest and Northeast through six pipeline systems in which TransCanada holds the following ownership interests:

Trans Québec & Maritimes System (TQM) 50 per cent;

Great Lakes Gas Transmission System (Great Lakes) 50 per cent;

Iroquois Gas Transmission System (Iroquois) 44.5 per cent;

Portland Natural Gas Transmission System (Portland) 61.7 per cent;

Northern Border Pipeline (Northern Border) 4 per cent; and

Tuscarora Gas Transmission System (Tuscarora) 7.6 per cent.

Northern Development

In 2005, TransCanada continued to pursue pipeline opportunities to move both Mackenzie Delta and Alaska North Slope natural gas to markets throughout North America. If the Mackenzie Gas Pipeline Project and the Alaska Highway Pipeline Project are constructed and connected to TransCanada's existing infrastructure, they will represent additional growth opportunities for TransCanada and enhance the long-term viability and value of the company's existing Gas Transmission business, especially the wholly-owned pipelines.

Mexico

In June 2005, TransCanada was awarded a contract to construct, own and operate a natural gas pipeline in east-central Mexico. The 36 inch, 125 km Tamazunchale Pipeline will extend from the facilities of Pemex Gas near Naranjos, Veracruz and transport natural gas to an electricity generation station near Tamazunchale, San Luis Potosi. TransCanada expects to invest approximately US$181 million in the project with a planned in-service date of December 1, 2006. The pipeline will be designed to transport initial volumes of 170 million cubic feet per day (mmcf/d). Under the contract, the capacity of the Tamazunchale Pipeline is expected to be expanded beginning in 2009 to approximately 430 mmcf/d to meet the needs of two additional proposed power plants near Tamazunchale. TransCanada continues to explore other pipeline and energy infrastructure opportunities in Mexico.

LNG

TransCanada continues to work toward gaining regulatory approval for its two LNG projects: Cacouna in Québec, a joint venture with Petro-Canada; and the Broadwater Energy project (Broadwater), offshore of New York State in Long Island Sound, a joint venture with Shell US Gas & Power LLC (Shell). TransCanada, on behalf of Broadwater, filed a formal application with the U.S. Federal Energy Regulatory Commission (FERC) on January 30, 2006 for federal approval to construct and operate Broadwater.

Natural Gas Storage

The company's initiatives in the natural gas storage business are a logical extension of its Gas Transmission business. TransCanada believes Alberta-based natural gas storage will continue to serve market needs and could play an important role should northern gas be connected to North American markets. In the first quarter of 2005, TransCanada started development of a natural gas storage facility near Edson, Alberta. The Edson facility is expected to have a capacity of approximately 60 petajoules (PJ) and will connect to TransCanada's Alberta System. In addition, in 2004, the company secured a long-term contract with a third party for existing Alberta-based natural gas storage capacity, increasing from 20 PJ in 2005 to 30 PJ in 2006 and to 40 PJ in 2007. These initiatives, combined with the company's current 60 per cent ownership interest in CrossAlta Gas Storage & Services Ltd. (CrossAlta), position TransCanada to become one of the largest natural gas storage providers in Western Canada. With more than 130 PJ of storage capacity by 2007, TransCanada will own or lease approximately one-third of the natural gas storage capacity available in Alberta.

Oil Transmission

In November 2005, TransCanada, ConocoPhillips Company and ConocoPhillips Pipe Line Company (CPPL), a wholly-owned subsidiary of ConocoPhillips Company, signed a Memorandum of Understanding (MOU) which commits ConocoPhillips Company to ship crude oil on the proposed Keystone oil pipeline (Keystone pipeline), and gives CPPL the right to acquire up to a 50 per cent participating interest in the pipeline. On January 31, 2006, TransCanada announced that through the binding Open Season held in fourth quarter 2005 it had secured firm, long-term contracts totalling 340,000 barrels per day of crude oil with an average term of 18 years. The Keystone pipeline, expected to cost approximately US$2.1 billion, will have an initial capacity to transport approximately 435,000 barrels per day of crude oil from Hardisty, Alberta to Patoka, Illinois through a 2,960 km pipeline system.

Regulatory

In 2005, TransCanada's principal regulatory activities and events included:

- a decision by the NEB to increase the deemed equity ratio of the Canadian Mainline to 36 per cent from 33 per cent following the completion of the hearings of the Canadian Mainline's 2004 Tolls and Tariff Application (Phase II);

- a negotiated settlement with respect to 2005 Canadian Mainline tolls;

a revenue requirement settlement for 2005, 2006 and 2007 for the Alberta System;

a hearing before the Alberta Energy and Utilities Board (EUB) on the rate design of the Alberta System, with potential implications for the competitiveness of the Alberta System;

an agreement with the Canadian Association of Petroleum Producers (CAPP) and other stakeholders to increase the deemed common equity ratios on the Foothills System and the BC System to 36 per cent from 30 per cent, effective January 1, 2006; and

commencement of settlement negotiations with its Canadian Mainline shippers regarding 2006 tolls.

Power

TransCanada has built a substantial power business over the past decade. The power plants and power supply that TransCanada owns, operates and/or controls, including projects under construction, represent approximately 6,700 megawatts (MW) of power generation capacity in Canada and the U.S. The company's power assets are concentrated in two main regions the western business focused in Alberta and the eastern business focused in the Northeastern U.S. and Eastern Canada markets.

Strategy

TransCanada's strategy for growth and value creation in Power is driven by four principles:

acquire low-cost, base-load generation in markets it knows. The company believes that being a low-cost provider is critical to being successful in volatile power markets;

develop low-risk, greenfield generation projects, backed by long-term input and sales contracts with quality counterparties. The company believes that long-term contracts are an essential part of most greenfield development projects;

actively participate in markets that are in transition. The changes that took place in Alberta and the Northeastern U.S., and the changes that continue in Ontario and Québec, allow the company to capture opportunities that are created as a result of power markets in transition; and

optimize the existing asset portfolio by running the company's facilities as efficiently and cost-effectively as possible through operational excellence.

TransCanada's ability to successfully execute its strategy is directly related to the following core competencies in the power business:

broad understanding of North American energy markets and a deep understanding of its core markets in Alberta, Eastern Canada and the Northeastern U.S.;

active participation in deregulated and deregulating markets;

ability to structure transactions and manage risk which is critical to mitigating volatility and uncertainty for industrial customers and shareholders;

a strong financial position which allows the company to build large-scale infrastructure and gives it the ability to act quickly on quality opportunities as they arise; and

strong project development, project management and operational skills.

In 2005, TransCanada continued to add to its diverse portfolio of quality power generation assets.

Bécancour and Cartier Wind

Throughout 2005, TransCanada continued to advance the Bécancour and Cartier Wind Energy (Cartier Wind) power projects. Construction of the 550 MW Bécancour cogeneration plant near Trois Rivières, Québec, remains on schedule to begin operations in September 2006. The 739.5 MW Cartier Wind project, 62 per cent owned by TransCanada, awarded construction contracts in late 2005, and is expected to commence construction in early 2006. Located in the

Gaspésie region of Québec, the first of the six projects that comprise Cartier Wind is anticipated to be commissioned beginning in late 2006 with the remaining projects being commissioned through to 2012. The entire power output from both Bécancour and Cartier Wind will be supplied to Hydro-Québec Distribution (Hydro-Québec) under 20 year power purchase contracts.

TC Hydro

In April 2005, TransCanada acquired from USGen New England, Inc. (USGen), hydroelectric generation assets (TC Hydro) with total generating capacity of 567 MW, for approximately US$503 million. These are low operating cost power generation assets serving the New England market.

Bruce Power

In October 2005, Bruce Power and the Ontario Power Authority (OPA), entered into a long-term agreement whereby Bruce A will restart and refurbish the currently idle Units 1 and 2, extend the operating life of Unit 3 by replacing its steam generators and fuel channels when required and replace the steam generators on Unit 4. The capital program for the restart and refurbishment work is expected to total approximately $4.25 billion and TransCanada's approximate $2.125 billion share will be financed through capital contributions to 2011. Work to refurbish Units 1 and 2 was initiated in 2005 and the first unit is expected to be on-line in 2009. Restarting Units 1 and 2 will add approximately 1,500 MW to Bruce Power's existing generation capacity of 4,700 MW. All of the Bruce A output will be sold to the OPA under fixed price contract terms.

As a result of the agreement between Bruce Power and the OPA, and the decision by Cameco Corporation (Cameco) not to participate in the restart and refurbishment program, a new partnership, Bruce A, was created. The Bruce A partnership subleases the Bruce A facilities, comprised of Units 1 to 4, from Bruce B. The effect of these transactions was that TransCanada and BPC Generation Infrastructure Trust (BPC) each incurred a net cash outlay of $100 million and as at December 31, 2005 each owned a 47.9 per cent interest in Bruce A.

Sheerness PPA

In December 2005, TransCanada acquired the remaining rights and obligations under the 756 MW Sheerness Power Purchase Arrangement (PPA) from the Alberta Balancing Pool for $585 million. The remaining term of the PPA is 15 years. The Sheerness power plant, which consists of two low-cost coal-fired thermal power generating units, is located approximately 230 km northeast of Calgary, Alberta.

Grandview

Construction of the 90 MW Grandview natural gas-fired cogeneration power plant located in Saint John, New Brunswick, was completed at the end of 2004. It was commissioned in January 2005. Under a 20 year tolling arrangement, 100 per cent of the plant's heat and electricity output is sold to Irving Oil (Irving).

TransCanada expects its Power business to continue to be a key growth driver. The company is committed to growing the Power business through asset acquisitions, selected greenfield developments and further expansions of its existing business. TransCanada's goal is to build and establish a diverse portfolio of high quality assets that deliver strong returns to shareholders.

OPERATIONAL EXCELLENCE AND "SPIRIT"

In addition to growing its Gas Transmission and Power businesses, TransCanada is committed to an operational excellence business model. The company's focus is on being a low-cost, reliable and safe operator that provides responsive services to its customers in an effective and timely manner.

The company's values guide the way business is conducted at TransCanada. Within TransCanada, these values are commonly referred to as "SPIRIT". They are the principles that direct how the company works and they include: Social responsibility, Passion, Integrity, Results, Innovation and Teamwork. The company's commitment to these values helps ensure it maintains its reputation as one of North America's premier energy infrastructure companies.

COMPETITIVE STRENGTH AND ENDURING VALUE

TransCanada's strategy also focuses on developing and enhancing those strengths that are at the core of its corporate success:

- developing excellence in value-creating strategy, analysis and investment execution;
- continuing to improve its financial capacity and flexibility;
- maintaining its corporate governance initiatives and its culture of honesty and integrity;
- developing and sustaining its relationships and reputation with all key stakeholders; and
- creating sustainable organizational and people strengths.

These initiatives bring competitive advantage and facilitate the effective delivery of results for the company's Gas Transmission and Power businesses.

TransCanada has approximately 2,350 employees who through their talent, integrity, hard work and results provide the company with a strong competitive advantage driven by industry-leading expertise in pipeline and power operations, depth of market and industry knowledge, financial acumen and exceptional infrastructure project capabilities.

OUTLOOK

TransCanada's corporate strategy is underpinned by a long-term focus on growing its Gas Transmission and Power businesses in a disciplined and measured manner. This strategy was initiated in 2000 and has been consistently followed. In 2006 and beyond, the company's net earnings and cash flow, combined with a strong balance sheet, are expected to continue to provide the financial flexibility for TransCanada to capture further opportunities and create additional long-term value for shareholders.

In Gas Transmission, the company will continue to focus its efforts on maximizing the long-term value from its pipeline and natural gas storage assets, including efforts to connect new long-term supply to growing markets. This focus will take a variety of forms in 2006 including:

- working with natural gas producers and the Aboriginal Pipeline Group (APG), including participating in regulatory proceedings as may be required, to advance the Mackenzie Gas Pipeline Project with an ultimate goal of connecting new northern natural gas supply to TransCanada's existing facilities and obtaining an equity ownership interest in the project;
- working with natural gas producers and the State of Alaska to advance the proposed Alaska Highway Pipeline Project, thereby connecting another source of northern natural gas supply to TransCanada's facilities;
- advancing development of the Cacouna and Broadwater LNG facilities which will, upon completion, connect new natural gas supply to existing and growing markets in Eastern North America. TransCanada will have a 50 per cent ownership interest in each of these projects and these new natural gas supplies are expected to increase natural gas flows on certain of TransCanada's natural gas pipeline systems;
- advancing development of the innovative Keystone pipeline which includes conversion of a portion of TransCanada's existing facilities from natural gas to crude oil transmission, thereby providing cost-effective and much needed pipeline capacity for the Alberta oil sands;

completing construction of the Tamazunchale natural gas pipeline in Mexico, which is expected at the end of 2006;

continuing discussions with Canadian Mainline stakeholders towards a settlement on 2006 tolls;

advancing the expansion of the North Baja System;

transitioning to the operatorship of Northern Border Pipeline in early 2007; and

filing a rate case with FERC with a goal of establishing new rates for the Gas Transmission Northwest System.

In addition, Gas Transmission will continue to grow its natural gas storage business in 2006 through completion of the Edson facility, an expanded CrossAlta facility and increased capacity under a long-term contract with a third party. TransCanada will also seek to continue to capitalize on opportunities to increase its ownership in its partially-owned pipelines and acquire interests in new pipelines in markets where TransCanada has a significant regional presence.

In Power, TransCanada has had significant success in growing this segment and, in 2006, will continue to focus its efforts on further growth. As in 2005 and prior years, this growth is expected to come from a combination of greenfield developments, new acquisitions and organic growth within its existing assets and markets. In particular, in 2006, TransCanada is expected to:

- work with Bruce A and its partners to advance the restart and refurbishment of the Bruce A units;
- complete construction of the 550 MW Bécancour power plant in late 2006;
- complete construction of the first of six Cartier Wind projects at the end of 2006 and continue construction of the second wind facility;
- integrate the newly acquired Sheerness PPA into Power's Western Operations; and
- pursue additional greenfield projects and acquisition opportunities in TransCanada's key regional markets.

The following discussion reflects management's expectations for 2006, as discussed throughout this MD&A. A number of risk factors and developments may positively or negatively affect the actual results for 2006, including new acquisitions, advancement of greenfield developments, regulatory decisions and settlements, customer bankruptcies, market changes in commodity prices, weather and interest rates as well as unplanned outages on various Gas Transmission and Power assets. The performance of the Canadian dollar relative to the U.S. dollar would either positively or negatively impact TransCanada's net earnings, although this impact is mitigated by partially offsetting exposures in certain of the company's businesses as well as through the company's hedging activities.

In 2006, TransCanada expects reduced net earnings from the Gas Transmission business compared to 2005 (excluding the gain on sale of PipeLines LP units in 2005). The combined effects of an expected net decline in the rate base of each of the Canadian Mainline and Alberta System and the decline in each of their respective allowed ROEs are expected to decrease net earnings on these systems compared to 2005. In addition, reduced firm contract volumes on the Gas Transmission Northwest System, partially due to the effects of customer bankruptcies, are expected to have a slightly negative impact on the Gas Transmission Northwest System results compared to 2005, although it is uncertain what impact the 2006 rate case filing may have on the system's results. Lastly, anticipated lower firm service revenues on certain partially-owned pipelines and a full year of reduced ownership of PipeLines LP are expected to be only partially offset by the effects of a higher allowed deemed common equity component on the Foothills System and the BC System and the expected growth in natural gas storage net earnings.

In the Power business, 2006 net earnings are expected to be higher than in 2005 (excluding the gains on sales related to Power LP and Paiton Energy in 2005) due to higher Bruce Power results reflecting an increased ownership in Bruce A and fewer planned outages, increased contributions from Western Operations reflecting the acquisition of the Sheerness PPA, slightly improved Eastern Operations' results reflecting a full year of TC Hydro operations as well as initial contributions from Bécancour and Cartier Wind expected in late 2006. Offsetting these improved results is the loss of income due to the sale of Power LP in 2005.

In 2006, Corporate is expected to incur higher net expenses compared to 2005 primarily due to the income tax refunds and positive income tax adjustments recorded in 2005 that are not currently expected to recur in 2006. In addition, Corporate's results in 2006 could be impacted by debt levels, interest rates, foreign exchange movements and income tax refunds and adjustments.

GAS TRANSMISSION

HIGHLIGHTS

Net Earnings

Net earnings from Gas Transmission increased $98 million to $684 million in 2005 compared to $586 million in 2004.

This increase is primarily due to a full year of GTN earnings in 2005 and the gain on sale of PipeLines LP units.

Canadian Mainline

The NEB, in its decision on the 2004 Tolls and Tariff Application (Phase II), approved an increase in the deemed common equity component of the Canadian Mainline's capital structure to 36 per cent from 33 per cent, effective January 1, 2004.

The NEB approved a negotiated settlement of 2005 Canadian Mainline tolls.

Alberta System

The EUB approved a three year revenue requirement settlement negotiated with shippers and other stakeholders. The settlement finalized the 2005 revenue requirement as well as established a framework for calculating the 2006 and 2007 revenue requirements. Most costs are treated on a flow through basis but certain costs have been fixed in each of the three years.

GTN

GTN contributed $71 million of earnings in 2005.

Successfully integrated into TransCanada's business.

Foothills System and BC System

Following an agreement with CAPP and other stakeholders to increase the deemed common equity component of the capital structure to 36 per cent from 30 per cent for the Foothills System and BC System and discussions with its shippers on those two systems, on December 2, 2005, TransCanada filed applications with the NEB for final 2006 tolls. On December 21, 2005, the NEB approved the Foothills System 2006 tolls as final tolls, effective January 1, 2006. On February 22, 2006, the NEB finalized the BC System's 2006 tolls as filed.

Other Gas Transmission

TransCanada sold approximately 3.5 million common units of PipeLines LP for an after-tax gain on sale of approximately $49 million.

TransCanada continued to fund the APG participation in the Mackenzie Gas Pipeline Project.

TransCanada commenced development of a natural gas storage project near Edson, Alberta.

TransCanada was awarded the contract to construct, own and operate the Tamazunchale Pipeline in east-central Mexico. Construction commenced in 2005.

TransCanada closed the acquisition of a 3.5 per cent ownership interest in Iroquois, increasing its ownership interest to 44.5 per cent.

CANADIAN MAINLINE TransCanada's 100 per cent owned, 14,898 km natural gas transmission system in Canada extends from the Alberta/Saskatchewan border east to the Québec/Vermont border and connects with other natural gas pipelines in Canada and the U.S.

ALBERTA SYSTEM TransCanada's 100 per cent owned natural gas transmission system in Alberta gathers natural gas for use within the province and delivers it to provincial boundary points for connection with the Canadian Mainline, BC System, the Foothills System and other pipelines. The 23,339 km system is one of the largest carriers of natural gas in North America.

GAS TRANSMISSION NORTHWEST SYSTEM TransCanada's 100 per cent owned, 2,174 km natural gas transmission system links the BC System and the Foothills System with Pacific Gas and Electric Company's California Gas Transmission System, with the Northwest Pipeline and with Tuscarora, a partially-owned entity that runs from the Oregon/California border into Nevada.

FOOTHILLS SYSTEM TransCanada's 100 per cent owned, 1,040 km natural gas transmission system in Western Canada carries natural gas for export from central Alberta to the U.S. border to serve markets in the U.S. Midwest, Pacific Northwest, California and Nevada.

BC SYSTEM TransCanada's 100 per cent owned natural gas transmission system extends 201 km from Alberta's western border through British Columbia to connect with the Gas Transmission Northwest System at the U.S. border, serving markets in B.C. as well as the Pacific Northwest, California and Nevada.

NORTH BAJA SYSTEM TransCanada's 100 per cent owned, 129 km natural gas transmission system extends from southwestern Arizona to a point near Ogilby, California on the California/Mexico border and connects with the Gasoducto Bajanorte pipeline system in Mexico.

VENTURES LP Ventures LP, which is 100 per cent owned by TransCanada, owns a 121 km pipeline and related facilities which supply natural gas to the oil sands region of northern Alberta, and a 27 km pipeline which supplies natural gas to a petrochemical complex at Joffre, Alberta.

GREAT LAKES Great Lakes connects with the Canadian Mainline at Emerson, Manitoba and serves markets in central Canada and the eastern and midwestern U.S. TransCanada has a 50 per cent ownership interest in this 3,402 km pipeline system.

TQM TQM is a 572 km natural gas pipeline system which connects with the Canadian Mainline and transports natural gas from Montréal to Québec City and to the Portland system. TransCanada holds a 50 per cent ownership interest in TQM.

IROQUOIS Iroquois connects with the Canadian Mainline near Waddington, New York and delivers natural gas to customers in the Northeastern U.S. TransCanada has a 44.5 per cent ownership interest in this 663 km pipeline system.

PORTLAND Portland is a 474 km pipeline that connects with TQM near East Hereford, Québec and delivers natural gas to customers in the Northeastern U.S. TransCanada has a 61.7 per cent ownership interest in Portland.

NORTHERN BORDER Northern Border is a 2,010 km natural gas pipeline system which serves the U.S. Midwest from a connection with the Foothills System near Monchy, Saskatchewan. TransCanada indirectly owns approximately 4 per cent of Northern Border through its 13.4 per cent ownership interest in PipeLines LP.

TUSCARORA Tuscarora operates a 386 km pipeline system transporting natural gas from the Gas Transmission Northwest System at Malin, Oregon to Wadsworth, Nevada with delivery points in northeastern California and northwestern Nevada. TransCanada owns an aggregate 7.6 per cent interest in Tuscarora, of which 6.6 per cent is held through TransCanada's interest in PipeLines LP.

TAMAZUNCHALE TransCanada is currently constructing the Tamazunchale natural gas pipeline in east central Mexico. The 125 km pipeline will extend from the facilities of Pemex Gas near Naranjos, Veracruz to an electricity generation station near Tamazunchale, San Luis Potosi. TransCanada will operate and own 100 per cent of the pipeline. This pipeline is expected to be in service on December 1, 2006.

TRANSGAS TransGas is a 344 km natural gas pipeline system which runs from Mariquita in the central region of Colombia to Cali in the southwest of Colombia. TransCanada holds a 46.5 per cent ownership interest in this pipeline.

GAS PACIFICO Gas Pacifico is a 540 km natural gas pipeline extending from Loma de la Lata, Argentina to Concepción, Chile. TransCanada holds a 30 per cent ownership interest in Gas Pacifico.

INNERGY INNERGY is an industrial natural gas marketing and distribution company based in Concepción, Chile that markets and distributes natural gas transported on Gas Pacifico. TransCanada holds a 30 per cent ownership interest in INNERGY.

CROSSALTA CrossAlta is an underground natural gas storage facility connected to the Alberta System and is located near Crossfield, Alberta. CrossAlta has a working natural gas capacity of 56 PJ with a maximum deliverability capability of 0.45 PJ per day. TransCanada holds a 60 per cent ownership interest in CrossAlta.

EDSON TransCanada is currently developing the Edson natural gas storage facility near Edson, Alberta. The Edson facility is expected to have a capacity of approximately 60 PJ and will connect to TransCanada's Alberta System. Storage capacity is expected to be available from the Edson facility, on a phased-in basis, commencing mid-2006.

BROADWATER Broadwater, a joint venture with Shell, is a proposed LNG project offshore of New York State in Long Island Sound, capable of receiving, storing and regasifying imported LNG with an average send-out capacity of approximately one Bcf/d of natural gas.

CACOUNA Cacouna, a joint venture with Petro-Canada, is a proposed LNG project at Gros Cacouna harbour on the St. Lawrence River, capable of receiving, storing and regasifying imported LNG with an average send-out capacity of approximately 500 mmcf/d of natural gas.

GAS TRANSMISSION RESULTS-AT-A-GLANCE

Year ended December 31 (millions of dollars)

	2005	2004	2003
Wholly-Owned Pipelines			
Canadian Mainline	**283**	272	290
Alberta System	**150**	150	190
GTN[1]	**71**	14	
Foothills System[2]	**21**	22	20
BC System	**6**	7	6
	531	465	506
Other Gas Transmission			
Great Lakes	**46**	55	52
Iroquois	**17**	17	18
PipeLines LP[3]	**9**	16	15
Portland[4]	**11**	10	11
Ventures LP[5]	**12**	15	10
TQM	**7**	8	8
CrossAlta	**19**	13	6
TransGas	**11**	11	22
Northern Development	**(4)**	(6)	(4)
General, administrative, support costs and other	**(24)**	(25)	(22)
	104	114	116
Gain on sale of PipeLines LP units (after tax)	**49**		
Gain on sale of Millennium (after tax)		7	
	153	121	116
Net earnings	**684**	586	622

(1) TransCanada acquired GTN on November 1, 2004. Amounts in this table reflect TransCanada's 100 per cent ownership interest in GTN's net earnings from the acquisition date.

(2) The remaining ownership interests in the Foothills System, previously not held by TransCanada, were acquired on August 15, 2003.

(3) During 2005, TransCanada decreased its ownership interest in PipeLines LP to 13.4 per cent from 33.4 per cent.

(4) TransCanada increased its ownership interest in Portland to 61.7 per cent from 33.3 per cent in 2003.

(5) TransCanada Pipeline Ventures Limited Partnership.

In 2005, net earnings from the Gas Transmission business were $684 million compared to $586 million and $622 million in 2004 and 2003, respectively. The increase in 2005 compared to 2004 was mainly due to higher net earnings from Wholly-Owned Pipelines and a gain on sale of PipeLines LP units, partially offset by lower net earnings from Other Gas Transmission. The increase in Wholly-Owned Pipelines' net earnings in 2005 was primarily due to a full year of GTN net earnings and higher Canadian Mainline net earnings. Lower net earnings in 2005 from Other Gas Transmission were primarily due to decreased earnings from Great Lakes and PipeLines LP, partially offset by higher earnings for CrossAlta.

The overall decrease of $36 million in 2004 Gas Transmission net earnings compared to 2003 was mainly due to lower net earnings from Wholly-Owned Pipelines. The decrease in Wholly-Owned Pipelines' net earnings in 2004 was primarily due to a reduction in the Alberta System's net earnings, reflecting the EUB's disallowance of certain operating costs in

its decision on Phase I of the 2004 General Rate Application (GRA) and in its decision in the generic cost of capital (GCOC) proceeding to allow an ROE in 2004 lower than the return implicit in the 2003 revenue requirement settlement with stakeholders. In addition, net earnings on the Canadian Mainline were lower in 2004 compared to 2003 due to a decline in both the average investment base and the allowed ROE. The addition of GTN had a positive effect on net earnings in 2004.

GAS TRANSMISSION FINANCIAL ANALYSIS

Canadian Mainline

The Canadian Mainline is regulated by the NEB. The NEB sets tolls which provide TransCanada the opportunity to recover projected costs of transporting natural gas, including the return on the Canadian Mainline's average investment base. In addition, new facilities are approved by the NEB before construction begins. Net earnings of the Canadian Mainline are affected by changes in investment base, the ROE, the level of deemed common equity and the potential for incentive earnings.

The Canadian Mainline generated net earnings of $283 million in 2005, an increase of $11 million over 2004. The increase in net earnings is primarily due to the NEB's decision on the 2004 Tolls and Tariff Application (Phase II) which included an increase in the deemed common equity ratio to 36 per cent from 33 per cent for 2004 which is also effective for 2005 under the tolls settlement. The Phase II decision resulted in a $35 million ($13 million related to 2004 and $22 million related to 2005) increase to Canadian Mainline's 2005 net earnings compared to 2004. However, this earnings increase was partially offset by the combination of a lower average investment base, lower operating cost savings and a lower approved ROE in 2005. The NEB-approved ROE decreased to 9.46 per cent in 2005 from 9.56 per cent in 2004.

Net earnings of $272 million in 2004 were $18 million lower than 2003 net earnings of $290 million. The decrease was primarily due to a lower average investment base and allowed ROE. The NEB-approved ROE was 9.56 per cent in 2004 compared to 9.79 per cent in 2003.

Alberta System

The Alberta System is regulated by the EUB primarily under the provisions of the *Gas Utilities Act (Alberta)* (GUA) and the *Pipeline Act (Alberta)*. Under the GUA, its rates, tolls and other charges, and terms and conditions of service are subject to approval by the EUB. In addition, major facilities are approved by the EUB before construction begins.

Net earnings of $150 million in 2005 were unchanged from 2004 due to the negative impacts of a lower investment base and a lower approved rate of return in 2005 being offset by the positive impact of higher allowed operating costs in 2005 than in 2004 as a result of cost disallowances in 2004 as a result of the EUB's decision on Phase I of the 2004 GRA. Net earnings in 2004 and 2005 reflect an ROE of 9.60 and 9.50 per cent, respectively, as prescribed by the EUB, on deemed common equity of 35 per cent.

Net earnings in 2004 of $150 million were $40 million lower than 2003 net earnings of $190 million. The decrease was primarily due to the impact of the EUB decisions in respect of Phase I of the 2004 GRA and the GCOC proceeding. The GRA Phase I decision disallowed approximately $24 million of operating costs, and the GCOC decision resulted in a lower return on deemed common equity in 2004 compared to 2003.

GTN

Both the Gas Transmission Northwest System and the North Baja System operate under fixed rate models, under which maximum and minimum rates for various service types have been ordered by FERC and which GTN is permitted to discount or negotiate on a non-discriminatory basis. The Gas Transmission Northwest System's last filed rate case was in 1994 and it was settled and approved by FERC in 1996. The North Baja System's rates were established in FERC's initial order in 2002, certifying construction and operation of the system. The net earnings of GTN are impacted by variations in volumes delivered and prices charged under the various service types that are provided, as well as by variations in the costs of providing transportation service. Net earnings were $71 million for the year ended December 31, 2005 compared to $14 million for November and December 2004.

Other Gas Transmission

TransCanada's other direct and indirect investments in various natural gas pipelines and gas transmission related businesses are included in Other Gas Transmission. It also includes TransCanada's natural gas storage facilities and project development activities related to TransCanada's pursuit of new pipeline and natural gas and crude oil transmission related opportunities throughout North America.

TransCanada's net earnings from Other Gas Transmission in 2005 were $153 million compared to $121 million and $116 million in 2004 and 2003, respectively. Excluding the gains on sale of PipeLines LP units in 2005 and Millennium in 2004, net earnings for 2005 were $10 million lower compared to 2004. The decrease was primarily due to lower net earnings of Great Lakes as a result of lower short-term revenues and higher operating and maintenance costs, and lower earnings from PipeLines LP as a result of the reduced ownership. Results were also negatively impacted by a weaker U.S. dollar in 2005. These decreases were partially offset by higher earnings from CrossAlta as a result of more favourable natural gas storage conditions in 2005.

Excluding the gain on sale of Millennium, net earnings in 2004 were $2 million lower than 2003. Higher net earnings from CrossAlta and Ventures LP were more than offset by an $11 million positive tax adjustment recorded in TransGas de Occidente S.A. (TransGas) in 2003 and the negative impact of a weaker U.S. dollar in 2004 compared to 2003.

GAS TRANSMISSION OPPORTUNITIES AND DEVELOPMENTS

Tamazunchale Pipeline

In June 2005, TransCanada announced it was awarded a contract by Mexico's Comisión Federal de Electricidad (CFE) to construct, own and operate a natural gas pipeline in east-central Mexico. The 36 inch, 125 kilometre Tamazunchale Pipeline will extend from the facilities of Pemex Gas near Naranjos, Veracruz and transport natural gas under a 26 year

contract with the CFE to an electricity generation station near Tamazunchale, San Luis Potosi. TransCanada expects to invest approximately US$181 million in the project with a planned in-service date of December 1, 2006.

The pipeline will be designed to transport initial volumes of 170 mmcf/d. Under the contract, the capacity of the Tamazunchale Pipeline is expected to be expanded beginning in 2009 to approximately 430 mmcf/d to meet the needs of two additional proposed power plants near Tamazunchale.

North Baja System

In February 2006, the North Baja System filed an application with FERC for a certificate for a two-phase expansion of its existing natural gas pipeline in southern California and the construction of a new pipeline lateral in California's Imperial Valley. The expansion project envisions substantially increasing the capacity of the existing pipeline and allowing for bi-directional flow of natural gas. Natural gas currently flows on the North Baja System southward from its interconnection with El Paso Natural Gas Company at Ehrenberg, Arizona.

The proposed North Baja System expansion links to a corresponding expansion of the Gasoducto Bajanorte line in Mexico owned by Sempra Energy. Together, the expansions may allow for import into the U.S. of up to 2.7 Bcfd/d of natural gas supplied from several potential LNG terminals near Baja California, Mexico, including the Costa Azul terminal that is currently under construction. Shippers have indicated their commercial support for the projects by signing precedent agreements in support of the expansion plan as filed with FERC.

In addition to its FERC certificate of public convenience and necessity (which includes a determination on environmental issues), the project will need various permits and leases from the federal Bureau of Land Management, the California State Lands Commission and other agencies.

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. Through 2005, the Mackenzie Gas Pipeline Project continued to progress, with substantial milestones being achieved in reaching agreement with certain of the northern aboriginal groups as to the terms of land access for the pipeline right of way. As a consequence, in late 2005, the project proponents indicated their readiness to proceed to the public hearings phase of the regulatory review of the project. Hearings commenced in January 2006 and are expected to continue throughout 2006.

In 2003, TransCanada entered into an agreement with the Mackenzie Valley Aboriginal Pipeline Limited Partnership (known as the APG) by which TransCanada agreed to finance the APG's one-third share of the pipeline pre-development costs associated with the Mackenzie Gas Pipeline Project. Cumulative advances made by TransCanada in this respect constitute a loan to the APG, which becomes repayable only after the date upon which the pipeline commences commercial operations. If the project does not proceed, TransCanada has no recourse against the APG for recovery of advances made.

TransCanada's loan advances to the APG were originally estimated to total approximately $90 million, with an acknowledgement that these costs could rise as a result of project delays and increased project costs. Given that the project has experienced delays and is entering into a protracted regulatory hearing process, the total loan advances by TransCanada, on behalf of the APG, are currently forecast to increase to approximately $145 million. These advances are expected to ultimately form part of the rate base of the pipeline, and the loan will subsequently be repaid from the APG's share of available future pipeline revenues or from alternate financing. As at December 31, 2005, TransCanada had funded $87 million of this loan. The ability to recover this investment remains dependent upon the successful outcome of the project. Under the terms of the agreement, TransCanada gains an immediate opportunity to acquire up to five per cent equity ownership of the pipeline at the time of the decision to construct. In addition, TransCanada gains certain rights of first refusal to acquire 50 per cent of any divestitures of existing partners and an entitlement to obtain a one-third interest in all expansion opportunities once the APG reaches a one-third ownership share, with the producers and the APG sharing the balance.

Alaska Highway Pipeline Project

In 2005, TransCanada continued its discussions with Alaska North Slope producers and the State of Alaska relating to the Alaskan portion of the proposed Alaska Highway Pipeline Project. In June 2004, TransCanada filed an application under the State of Alaska's *Stranded Gas Development Act* and requested the State resume processing of its long-pending application for a right-of-way lease across State lands. If the right-of-way lease is approved, TransCanada is prepared to convey the lease to another entity if that entity is willing to connect the final project to TransCanada's pipeline system. The lease conveyance would require an interconnection agreement with TransCanada at the Yukon/Alaska border. TransCanada's Stranded Gas Application is one of three applications currently before the State. In October 2005, the State Administration and ConocoPhillips Company reached a preliminary agreement under the *Stranded Gas Development Act*. On February 21, 2006, the State announced that it had reached a preliminary agreement with BP Resources and ExxonMobil. In addition, on February 21, 2006, the State announced it would be proposing legislation for a new oil and gas production tax regime. It is not expected that a natural gas deal would be submitted to the legislative assembly of Alaska for ratification until after a new oil and gas production tax regime has been enacted.

Foothills Pipe Lines Ltd. (Foothills) holds the priority right to build, own and operate the first pipeline through Canada for the transportation of Alaskan natural gas. This right was granted under the *Northern Pipeline Act of Canada* (NPA), following a lengthy competitive hearing before the NEB in the late 1970s, which resulted in a decision in favour of Foothills. The NPA creates a single window regulatory regime that is uniquely available to Foothills. It has been used by Foothills to construct facilities in Alberta, British Columbia and Saskatchewan which constitute a prebuild for the Alaska Highway Pipeline Project, and to expand those facilities five times, the latest of which was in 1998. TransCanada continues to seek commercial alignment with the Alaska North Slope producers on the Canadian portion of the project. Continued development under the NPA should ensure the earliest in-service date for the project.

Supply

In 2005, the upstream energy sector responded to high natural gas prices by drilling a record number of natural gas wells in the WCSB. TransCanada continued to see supply growth from the west central foothills area as well as unconventional production from coalbed methane (CBM), primarily from the Horseshoe Canyon coals located in central Alberta between Edmonton and Calgary.

TransCanada will continue to focus on the cost effective and timely connection of these volumes that will enable customers to access markets where natural gas continues to achieve premium prices. As well, service flexibility will continue to be a focus to ensure TransCanada remains competitive.

Western Markets

TransCanada continues to pursue growth opportunities within existing and new natural gas markets. In 2005, TransCanada further pursued the provision of cost effective incremental delivery service into the Fort McMurray, Alberta market. As demand for natural gas continued to grow at unprecedented levels, numerous oil sands projects, both mining and in-situ, were announced in this region in 2005 resulting in incremental natural gas demand.

In late 2004 and throughout 2005, TransCanada executed firm contracts for delivery service to the Fort McMurray area on the Alberta System for volumes in excess of 900 mmcf/d. As a result of the ten and 20 year contracts, TransCanada has filed applications with the EUB to construct new natural gas transmission facilities to serve the contracted demand. The construction will begin in late 2006 with a contracted on-stream date of April 1, 2007. In 2008 and 2009, TransCanada expects to add additional facilities as the Fort McMurray oil sands demand continues to grow.

Eastern Markets

Power generation continues to be the primary driver for incremental natural gas demand in Eastern Canada and the U.S. Northeast markets. Power projects that will require significant incremental natural gas volumes continue to be developed and, as a result, the Canadian Mainline is expected to see modest throughput increases in the short to medium term on a long haul basis. Modest expansions, underpinned with long term firm transportation (FT) contracts, are expected to be placed into service in 2006 and 2007 to meet incremental demand in the eastern markets.

Desire for options in accessing natural gas supply is reflected in the continuing trend towards increased demand for short haul contracts by customers in the eastern markets. TransCanada continues to work with these customers to provide service flexibility and optionality.

LNG

In September 2005, the village of Cacouna, Québec, voted 57.2 per cent in favour of an LNG terminal to be built in the area. The Cacouna Energy joint venture between Petro-Canada and TransCanada was originally announced in September 2004 and proposes a $660 million project at Gros Cacouna harbour on the St. Lawrence River, capable of receiving, storing and regasifying imported LNG with an average send-out capacity of approximately 500 mmcf/d of natural gas. TransCanada will operate the planned facility, while Petro-Canada will contract for all of the capacity and supply the LNG. Québec's Ministry of Environment commenced its 45 day public consultation period on February 22, 2006, regarding its next phase for this project.

In November 2004, TransCanada and Shell announced plans to jointly develop an offshore LNG regasification terminal, Broadwater, in the New York State waters of Long Island Sound. The proposed floating storage and regasification unit would be located approximately 15 km off the Long Island coast and 18 km off the Connecticut coast. The proposed terminal would be capable of receiving, storing and regasifying imported LNG with an average send-out capacity of approximately one Bcf/d of natural gas. Broadwater Energy LLC, an entity which will be owned 50 per cent by TransCanada, will own and operate the facility, while Shell will contract for all of the capacity and supply the LNG. The estimated cost of construction is expected to be approximately US$700 million to US$1 billion. Construction of the facility is subject to regulatory approval from U.S. federal and state governments. On January 30, 2006, a formal application was filed with FERC for federal approval to construct and operate Broadwater. Provided the necessary approvals are received, it is expected the facility will be in service in late 2010 or early 2011.

Natural Gas Storage

TransCanada's natural gas storage business is situated in Alberta, and is comprised of a long-term natural gas storage contract, 60 per cent ownership in CrossAlta and the wholly-owned Edson facility which is currently under construction. By mid-2007, TransCanada will own or lease more than 130 PJ, or approximately one-third of the natural gas storage capacity in Alberta.

Natural gas market price volatility, partly due to extreme weather, supply disruptions and sharp increases in oil prices, contributed to strong storage values during 2005. TransCanada commenced commercial natural gas storage operations in second quarter 2005 through marketing and optimizing the 20 PJ of contracted natural gas storage capacity. The capacity under contract increases to 30 PJ in 2006 and to 40 PJ in 2007.

TransCanada commenced construction of the Edson facility in early 2005. The construction cost of the project is currently expected to be approximately $270 million, which is a $70 million increase from the initial estimate due to higher drilling and construction costs, and higher base gas costs. The Edson facility is expected to have a capacity of approximately 60 PJ and will connect to TransCanada's Alberta System. Storage capacity is expected to be available from the Edson facility, on a phased-in basis, commencing in mid-2006.

TransCanada also has a 60 per cent interest in the CrossAlta natural gas storage facility, which has a total working natural gas capacity of 56 PJ. In 2005, CrossAlta completed expansion projects that improved the injection and withdrawal rates and increased developed capacity from 44 PJ to 56 PJ.

Current market fundamentals for natural gas storage are expected to remain strong. The imbalance in North American natural gas supply and demand has created natural gas price volatility, resulting in demand for storage service.

TransCanada believes Alberta-based storage will continue to serve market needs and could play an even more important role when northern natural gas is connected to North American markets.

Keystone Pipeline

In November 2005, TransCanada, ConocoPhillips Company and CPPL signed an MOU which commits ConocoPhillips Company to ship crude oil on the proposed Keystone pipeline, and gives CPPL the right to acquire up to a 50 per cent ownership interest in the pipeline. On January 31, 2006, TransCanada announced it has secured firm, long-term contracts totalling 340,000 barrels per day with a duration averaging 18 years. The commitments were obtained through the successful completion of a binding Open Season held during fourth quarter 2005. With these commitments from shippers, TransCanada will proceed with regulatory filings for approval of the project.

At an estimated cost of approximately US$2.1 billion, the Keystone pipeline is intended to transport approximately 435,000 barrels per day of crude oil from Hardisty, Alberta, to Patoka, Illinois through a 2,960 km pipeline system. The pipeline can be expanded to 590,000 barrels per day with additional pump stations. In addition to approximately 1,730 km of new pipeline construction in the U.S., the Canadian portion of the proposed project includes the construction of approximately 370 km of new pipeline and the conversion of approximately 860 km of TransCanada's existing pipeline facilities from natural gas to crude oil transmission. The Keystone pipeline, upon receipt of the appropriate regulatory approvals in Canada and the U.S., is expected to be in service in 2009. Construction is proposed to begin in late 2007.

Shippers have also expressed interest in proposed extensions of the Keystone pipeline to Cushing, Oklahoma and Fort Saskatchewan, Alberta. TransCanada expects to hold a binding Open Season for these two extensions later in 2006.

TransCanada is in the business of connecting energy supplies to markets and it views this opportunity as another way of providing a valuable service to its customers. Converting one of the company's natural gas pipeline assets for crude oil transportation is an innovative, cost-competitive way to meet the need for pipeline expansions to accommodate anticipated growth in Canadian crude oil production during the next decade.

GAS TRANSMISSION REGULATORY DEVELOPMENTS

In 2005, TransCanada's principal regulatory activities included receiving the decision from the NEB regarding the Canadian Mainline's 2004 Tolls and Tariff Application (Phase II); a negotiated settlement with respect to 2005 Canadian Mainline tolls; a three year revenue requirement settlement for the Alberta System; a hearing before the EUB on the rate design of the Alberta System, with potential implications for the competitiveness of the Alberta System; and the successful negotiation with shippers and CAPP for their support on increasing the deemed common equity ratio on the Foothills System and the BC System. TransCanada is also currently in negotiation for a settlement with its Canadian Mainline shippers regarding 2006 tolls.

Canadian Mainline

In April 2005, the NEB issued its decision on the Canadian Mainline's 2004 Tolls and Tariff Application (Phase II) which increased the Canadian Mainline deemed common equity to 36 per cent from 33 per cent for 2004 tolls.

In April 2005, the NEB approved TransCanada's application for a negotiated settlement of the 2005 Canadian Mainline tolls as filed. The settlement established operating, maintenance and administration (OM&A) costs for 2005 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 were to be treated on a flow through basis. Further, the 2005 ROE was set at 9.46 per cent and the deemed common equity component in 2005 reflected the outcome of the NEB's Phase II decision with respect to the Canadian Mainline's 2004 capital structure.

In May 2005, in compliance with the NEB's decision regarding the Canadian Mainline's 2004 Tolls and Tariff Application (Phase II), TransCanada filed separate final tolls applications with the NEB for 2004 and 2005. In June 2005, the NEB issued its decision approving the 2004 and 2005 final tolls applications as filed.

In December 2005, the NEB approved the 2006 interim tolls, effective January 1, 2006. TransCanada is currently engaged in settlement discussions with its stakeholders on matters related to the Canadian Mainline's 2006 tolls and

tariff. Pending progress on the settlement discussions, TransCanada intends to file an application for approval of the 2006 tolls and tariff with the NEB in first quarter 2006.

The formula-based ROE for the Canadian Mainline for 2006 is 8.88 per cent.

Alberta System

In December 2004, TransCanada filed its 2005 Phase I GRA with the EUB. In March 2005, a settlement was reached with shippers and other interested parties regarding 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 were fixed at $193 million for 2005, $201 million for 2006, and $207 million for 2007. Any variance between actual OM&A and other fixed costs and those agreed to in the settlement in each year accrue to TransCanada. The majority of other cost elements of the 2005, 2006 and 2007 revenue requirements are treated on a flow through basis.

The return on equity 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, ROE under the EUB formula was 9.50 per cent. In addition, depreciation expenses are determined using the depreciation rates and methodology that was proposed to the EUB in the 2004 GRA. Depreciation expense was $303 million in 2005 and is expected to be approximately $285 million in 2006 and $282 million in 2007.

In June 2005, the EUB approved the negotiated settlement of the Alberta System's three year revenue requirement. As stipulated in the settlement, TransCanada then discontinued the action it had commenced to appeal the EUB's disallowance of certain incentive compensation and long-term incentive compensation costs in the 2004 revenue requirement and its work on an application to the EUB to review and vary this same decision.

Interim tolls approved in December 2004 were charged throughout 2005 for transportation service on the Alberta System. With the issuance on February 21, 2006 of the EUB's decision on Phase II of the Alberta System's 2005 GRA, in which the application to retain the Alberta System's current rate design and cost allocation methodologies was approved, final tolls for 2005 can be determined. An application for 2005 final tolls will be made in March 2006.

On December 15, 2005, the EUB approved the application to charge interim tolls for transportation service, effective January 1, 2006. The 2006 interim tolls, which replaced the 2005 interim tolls, will be finalized through an application to the EUB in March 2006 in which the flow-through cost components of the revenue requirement will be updated to reflect actual costs and revenues from the prior year as stipulated under the Alberta System's 2005, 2006 and 2007 revenue requirement settlement.

The formula-based ROE for the Alberta System for 2006 is 8.93 per cent.

GTN

TransCanada is preparing a rate case for the Gas Transmission Northwest System that is expected to be filed by summer 2006. The primary reason for a rate case is decreased revenues due to contract non-renewals and shipper defaults. Currently, the Gas Transmission Northwest System has about 12 per cent of its long-term capacity unsubscribed and there is a risk of additional contracts not being renewed during the remainder of 2006. FERC typically suspends the effectiveness of rate increase filings for a five month period, so the company anticipates that the new rates, which are subject to refund pending the final result of the case, would go into effect near the end of 2006.

Foothills and BC Systems

TransCanada filed applications with the NEB in early December 2005 for approval of 2006 tolls for the Foothills System and the BC System reflecting an agreement with CAPP and other stakeholders to increase the deemed equity component of the capital structure of each system to 36 per cent from 30 per cent. On December 21, 2005, the NEB approved the Foothills System application as filed. On February 22, 2006, the NEB finalized the BC System's 2006 tolls as filed.

Competition

TransCanada faces competition at both the supply end and the market end of its systems. The competition is a result of other pipelines accessing an increasingly mature WCSB and markets served by TransCanada's pipelines. In addition, the continued expiration of long-term FT contracts has resulted in significant reductions in long-term firm contracted capacity on the Canadian Mainline, the Alberta System, the BC System and the Gas Transmission Northwest System, and shifts to short-term firm contracts.

As of December 2004, the WCSB had remaining discovered natural gas reserves of approximately 55 trillion cubic feet and a reserves-to-production ratio of approximately nine years at current levels of production. Historically, additional reserves have continually been discovered to maintain the reserves-to-production ratio at close to nine years. Natural gas prices in the future are expected to be higher than long-term historical averages due to a tighter supply/demand balance which should stimulate exploration and production in the WCSB. However, WCSB supply is expected to remain essentially flat. With the expansion of capacity on TransCanada's wholly- and partially-owned pipelines over the past decade, and the competition provided by other pipelines, combined with significant growth in natural gas demand in Alberta, TransCanada anticipates there will be excess pipeline capacity out of the WCSB for the foreseeable future.

TransCanada's Alberta System is the major natural gas gathering and transportation system for the WCSB which connects most of the natural gas processing plants in Alberta to domestic and export markets. The Alberta System has faced, and will continue to face, increasing competition from other pipelines.

The Canadian Mainline is TransCanada's cross-continental natural gas pipeline serving mid-western and eastern markets in Canada and the U.S. The demand for natural gas in TransCanada's key eastern markets is expected to continue to increase, particularly to meet the expected growth in natural gas-fired power generation. Although there are opportunities to increase market share in Canadian and U.S. export markets, TransCanada faces significant competition in these regions. Consumers in the U.S. Northeast have access to an array of pipeline and supply options. Eastern Canadian markets that historically received Canadian supplies only from TransCanada are now capable of receiving supplies from new pipelines into the region that can source Western Canadian, Atlantic Canadian and U.S. supplies.

Over the last few years, the Canadian Mainline has experienced reductions in long haul FT contracts. This has been partially offset by increases in short haul contracts. While decreases in throughput do not directly impact Canadian Mainline earnings, such decreases will impact the competitiveness of its tolls. Over the course of 2005, strong natural gas prices in Eastern Canada and the Northeast U.S. resulted in higher than anticipated flows on the Canadian Mainline to serve those markets. In addition to increases in flow, the Canadian Mainline has also experienced an increase in short-term contracts and a resulting decrease in tolls. Looking forward, in the short to medium term, there is expected to be limited opportunity to further reduce tolls by increasing long haul volumes on the Canadian Mainline. Further, throughput and contract levels are expected to return to more modest levels.

The Gas Transmission Northwest System must compete with other pipelines to access natural gas supplies as well as to access markets. Transportation service capacity on the Gas Transmission Northwest System provides customers with access to supplies of natural gas primarily from the WCSB and serves markets in the Pacific Northwest, California and Nevada. These three markets may also access supplies from other competing basins in addition to supplies from the WCSB. Historically, natural gas supplies from the WCSB have been competitively priced in relation to natural gas supplies from the other supply regions serving these markets. The Gas Transmission Northwest System experienced contract non-renewals in 2005 and additional contracts may not be renewed in 2006. Natural gas transported from the WCSB on the Gas Transmission Northwest System competes in the California and Nevada markets against supplies from the Rocky Mountain and southwest U.S. supply basins. In the Pacific Northwest market, natural gas transported on the Gas Transmission Northwest System competes against Rocky Mountain gas supply as well as additional Western Canadian supply that is transported by the Northwest Pipeline.

Transportation service on the North Baja System provides access to natural gas supplies primarily from both the Permian Basin, located in western Texas and southeastern New Mexico, and the San Juan Basin, primarily located in northwestern New Mexico and Colorado. The North Baja System delivers natural gas to the Gasoducto Bajanorte

pipeline at the California/Mexico border, which transports the natural gas to markets in northern Baja California, Mexico. While there are currently no direct competitors to deliver natural gas to the North Baja System's downstream markets, the pipeline may compete with fuel oil which is an alternative to natural gas in the operation of some electric generation plants in the North Baja region.

Counterparty Risk

The risk of customer defaults and bankruptcy has always been present. In December 2005, Calpine Corporation and certain of its subsidiaries (Calpine) filed for bankruptcy protection. Calpine has transportation contracts on certain of TransCanada's Canadian and U.S. pipelines. TransCanada presently holds the maximum financial assurances allowable under the respective tariffs. As at February 27, 2006, these transportation contracts had not been accepted or rejected. Should the Calpine contracts with TransCanada's Canadian pipeline systems be rejected, TransCanada considers that it has been prudent in obtaining the maximum financial assurances and would make an application to the regulator for recovery under the current regulatory model of any lost revenue, net of the assurances, and any revenues from the defaulted capacity. Should contracts be rejected on TransCanada's U.S. systems, the unmitigated annual after-tax exposure of the contract obligations is estimated at $10 million for the Gas Transmission Northwest System and $10 million for Portland Natural Gas Transmission System Partnership, in which TransCanada holds a 61.7 per cent ownership interest. Mitigating factors exist which are expected to reduce this exposure including recovery through future general rate case filings, recontracting at maximum or discounted rates where applicable, recontracting as short-term or interruptible service, and recovery from bankruptcy proceedings. The potential impact of such mitigating factors and the resulting net exposure are unknown at this time.

Financial Risk

Regulatory decisions continue to have a significant impact on the financial returns for existing and future investments in TransCanada's Canadian wholly-owned pipelines. TransCanada remains concerned the approved financial returns discourage additional investment in existing Canadian natural gas transmission systems. TransCanada had applied for a return of 11 per cent on 40 per cent deemed common equity for both the Canadian Mainline and the Alberta System to the NEB and EUB, respectively. The outcome of these proceedings resulted in the current Canadian Mainline's 36 per cent deemed equity thickness and Alberta System's 35 per cent deemed equity thickness. Additionally, the NEB reaffirmed its return on equity formula, while the EUB set a generic ROE which largely aligns with the formula of the NEB. In 2005, the NEB's ROE formula provided an ROE of 9.46 per cent and the EUB's generic ROE was 9.50 per cent. In 2006, the Canadian Mainline and Alberta System's ROEs decline to 8.88 percent and 8.93 per cent, respectively.

The company remains cognizant of the views and shares the concerns of credit rating agencies regarding the Canadian regulatory environment. Credit ratings and liquidity continue to be at the forefront of investor attention. While recent regulatory decisions increasing the deemed equity component of the capital structure of the company's Canadian pipelines may serve to somewhat mitigate these concerns in the long run, significantly reduced allowed ROE on NEB and EUB regulated pipelines are expected to offset any positive effect in 2006.

Foreign Exchange

TransCanada's earnings from GTN, as well as a significant amount of earnings in Other Gas Transmission are generated in U.S. dollars. The performance of the Canadian dollar relative to the U.S. dollar would either positively or negatively impact Gas Transmission's net earnings, although this impact is mitigated by offsetting exposures in certain of TransCanada's other businesses as well as through the company's hedging activities.

Throughput Risk

As transportation contracts expire on Great Lakes, Northern Border and GTN, these pipelines will be more exposed to throughput risk and their revenues will more likely experience increased variability. Throughput risk is created by supply and market competition, gas basin pricing, economic activity, weather variability, pipeline competition and pricing of alternative fuels.

Operational Excellence

TransCanada continued its commitment to operational excellence in 2005 by further advancing initiatives that will improve the company's ability to provide low-cost, reliable and responsive service to customers. TransCanada continues to pursue the operational excellence strategy in order to continue to be the preferred company for customers wishing to connect new natural gas supplies and markets.

TransCanada maintained a high level of plant operating performance, as measured by the number of operational perfect days on both the Canadian Mainline and the Alberta System. GTN was effectively integrated in 2005, and maintained high levels of operating performance as well.

Receiving the American Society of Mechanical Engineers' inaugural award for pipeline technology in 2005 further recognized the efforts of TransCanada to ensure high reliability levels are sustained over the long term.

The annual Customer Satisfaction Survey, conducted by Ipsos Reid in the fall of 2005, found that TransCanada maintained high levels of overall customer satisfaction and improved significantly in the area of senior management relationships. As part of the Customer Express website, TransCanada launched the "Toll Calculator", an online tool that allows customers to quickly obtain the cost of shipping on TransCanada's wholly-owned and affiliated pipeline systems. Feedback from customers and other stakeholders indicates this tool was well received and support for further development of on-line tools is strong.

Also, 2005 was a very productive year with respect to collaborative efforts with customers. The Tolls Task Force, the Canadian Mainline stakeholder group, produced twenty resolutions in 2005 including process improvements, several service enhancements, a new service and a settlement for the Canadian Mainline. The Tolls, Tariff, Facilities and Procedures committee, the Alberta System stakeholder group, had eleven resolutions in 2005 focusing on greater service flexibility and process efficiency for the Alberta System. Many of these initiatives will result in increasing service flexibility and more efficient service delivery. Productive collaborative processes also result in costs savings for both TransCanada and industry by avoiding costs associated with regulatory proceedings.

In 2006, TransCanada will continue to focus efforts on efficiencies, operational reliability, and environmental and safety performance. Greenhouse gas emissions management programs will continue to receive focused attention and in 2006 further efforts will be undertaken to improve contractor safety performance.

Safety

TransCanada worked closely with regulators, customers and communities during 2005 to ensure the continued safety of employees and the public. Pipeline safety performance in 2005 was very good with only one small diameter pipeline line-break located in a relatively remote area of northern Alberta. The break resulted in minimal impact with no injuries or property damage. Under the approved regulatory models in Canada, expenditures on pipeline integrity for the NEB and EUB regulated pipelines have no negative impact on TransCanada's earnings. The company expects to spend approximately $105 million in 2006 for pipeline integrity on its Wholly-Owned Pipelines, which is an increase from the $64 million spent in 2005. The increase is due primarily to initial inspections of the Gas Transmission Northwest System, additional inspections for stress corrosion cracking on the Canadian Mainline and repairs to several water crossings in southern Alberta that were damaged during flood events in June 2005. TransCanada continues to use a rigorous risk management system that focuses spending on issues and areas that have the largest impact on maintaining or improving the reliability and safety of the pipeline system.

Environment

In 2005, TransCanada continued to address and assess environmental issues through proactive sampling, monitoring and remediation programs. Activities on the Canadian Mainline included the completion of three ongoing remediation projects, as well as building containment integrity improvement projects at seven compressor stations. All facilities on the Foothills System were assessed through the company's Site Assessment, Remediation and Monitoring program in 2005, along with the majority of facilities on GTN. In addition, the decommissioning and reclamation of four Canadian

Mainline compressor plants and two Alberta System compressor plants was carried out in 2005. TransCanada will continue to actively invest in improved environmental protection measures.

For information on management of risks with respect to the Gas Transmission business, see the "Risk Management" section.

GAS TRANSMISSION OUTLOOK

As demand for natural gas continues to grow across North America, TransCanada's Gas Transmission business will continue to play a critical role in the reliable transportation of natural gas. For 2006, the business will focus on the reliable delivery of natural gas to growing markets, connecting new supply and progressing development of new infrastructure to connect northern gas. TransCanada will also focus on development of the Keystone pipeline.

Looking forward, it is expected that producers will continue to explore and develop new fields, particularly in northeastern B.C. and the west central foothills regions of Alberta, as well as unconventional supply such as gas production from CBM reserves. New facilities will be required to move this incremental supply based on the location of the resource, even though overall WCSB supply is expected to remain essentially flat. The Alberta System anticipates filing an application during 2006 with the EUB, to construct new facilities required to connect additional natural gas supplies anticipated to be delivered to the Alberta System from the Mackenzie Delta.

In 2006, TransCanada will continue to focus on serving the growing demand in the Fort McMurray area with construction of new natural gas transmission facilities, beginning in late 2006, with a contractual on-stream date of April 1, 2007. In 2008 and 2009, TransCanada anticipates constructing additional facilities as the Fort McMurray oil sands demand for natural gas continues to grow.

It is expected that incremental supply from LNG will serve growing North American markets in the mid to long term. As a result, TransCanada will take prudent steps to further evaluate the potential commercial and operational implications of connecting LNG facilities to those systems affected.

Prior to the onset of new supply from LNG and northern gas, many of the markets served by TransCanada's systems may be exposed to volatile natural gas prices. As a result, TransCanada will continue to focus on operational excellence and collaborative efforts with all stakeholders on negotiated settlements and service options that will increase the value of TransCanada's business to customers and shareholders.

Earnings

TransCanada's earnings from its Canadian wholly-owned pipelines are primarily determined by the average investment base, ROE, deemed common equity and opportunity for incentive earnings. In the short to medium term, the company expects a modest level of investment in these mature assets and therefore anticipates a continued net decline in the average investment base due to depreciation expense in excess of capital expenditures. Accordingly, without an increase in ROE, deemed common equity or incentive opportunities, future earnings are anticipated to decrease. However, these mature assets will continue to generate strong cash flows that can be redeployed to other projects offering higher returns. Under the current regulatory model, earnings from the Canadian wholly-owned pipelines are not affected by short-term fluctuations in the commodity price of natural gas, changes in throughput volumes or changes in contract levels.

In December 2005, the NEB established the 2006 ROE for the Canadian Mainline at 8.88 per cent compared to 9.46 per cent in 2005. In addition, the 2006 average investment base is expected to continue to decline. These two factors are expected to lower earnings on the Canadian Mainline in 2006 relative to 2005 if there are no offsetting factors. TransCanada is currently engaged in settlement discussions with its stakeholders on matters related to the Canadian Mainline's 2006 tolls.

Alberta System earnings in 2006 will be negatively influenced by the decrease in the EUB's generic ROE to 8.93 per cent in 2006 from 9.50 per cent in 2005, and an anticipated decrease in the average investment base. The three year revenue requirement settlement reached in 2005 does provide the opportunity for limited incentive earnings as the settlement contains some at-risk cost components. If TransCanada is successful in its focus on cost efficiency,

there is an opportunity to partially mitigate the effect of a lower ROE and average investment base for the Alberta System in 2006.

In 2006, earnings from Portland and the Gas Transmission Northwest System may be negatively impacted should Calpine contracts be rejected on the respective systems. Calpine's FT contract accounts for approximately 24 per cent of Portland's total FT revenues. On the Gas Transmission Northwest System, approximately seven per cent of transportation revenues come from Calpine's FT contracts. It is not possible at this time to determine the impact of any potential mitigating factors on 2006 earnings if these contracts are rejected.

Reduced firm contract volumes on the Gas Transmission Northwest System, including the effects of customer bankruptcies, are expected to have a slightly negative impact on the Gas Transmission Northwest System results compared to 2005. The impact of the 2006 rate case filing on the system's results in 2006 is uncertain at this time.

Anticipated lower firm service revenues on certain partially-owned pipelines and a full year of reduced ownership of PipeLines LP are expected to be partially offset by the effects of a higher deemed equity structure on the Foothills System and BC System and the expected growth in natural gas storage net earnings.

Capital Expenditures

Total capital spending for the Wholly-Owned Pipelines during 2005 was $135 million. Overall capital spending on the Wholly-Owned Pipelines in 2006 is expected to be approximately $382 million. Capital expenditures on the Edson natural gas storage project and the Tamazunchale Pipeline are expected to be approximately $105 million and $95 million, respectively, in 2006.

NATURAL GAS THROUGHPUT VOLUMES
(Bcf)[1]

	2005	2004	2003
Canadian Mainline[2]	2,997	2,621	2,628
Alberta System[3]	3,999	3,909	3,883
Gas Transmission Northwest System[4]	777	181	
Foothills System	1,051	1,139	1,110
BC System	321	360	325
North Baja System[4]	84	13	
Great Lakes	850	801	856
Northern Border	808	845	850
Iroquois	394	356	341
TQM	166	159	164
Ventures LP	192	136	111
Portland	62	50	53
Tuscarora	25	25	22
TransGas	19	18	16

(1) Billion cubic feet.

(2) Canadian Mainline deliveries originating at the Alberta border and in Saskatchewan for the year ended December 31, 2005 were 2,215 Bcf (2004 2,017 Bcf; 2003 2,055 Bcf).

(3) Field receipt volumes for the Alberta System for the year ended December 31, 2005 were 4,034 Bcf (2004 3,952 Bcf; 2003 3,892 Bcf).

(4) TransCanada acquired the Gas Transmission Northwest System and the North Baja System on November 1, 2004. The volumes for 2004 represent November and December 2004 throughput.

POWER

HIGHLIGHTS

Net Earnings

Power's net earnings in 2005 were $561 million compared to $396 million in 2004.

Excluding gains related to Power LP and Paiton Energy, Power's net earnings for 2005 increased $44 million to $253 million compared to $209 million in 2004.

TransCanada's operating and other income before income taxes from Bruce Power for 2005 of $195 million increased by $65 million compared to $130 million in 2004.

Expanding Asset Base

In October 2005, Bruce Power and the OPA completed a long-term agreement whereby Bruce A will restart and refurbish the currently idle Units 1 and 2, extend the life of Unit 3 by replacing its steam generators and fuel channels when required and replace the steam generators on Unit 4. Restarting Units 1 and 2, which have a capacity of approximately 1,500 MW, will boost Bruce Power's output to more than 6,200 MW of which approximately 2,450 MW is TransCanada's share. As at December 31, 2005, TransCanada owned 47.9 per cent of Bruce A and 31.6 per cent of Bruce B.

Effective December 31, 2005, TransCanada acquired the remaining rights and obligations of the 756 MW Sheerness PPA from the Alberta Balancing Pool for $585 million. The remaining term of the PPA is approximately 15 years. The plant consists of two coal-fired thermal power generating units.

In April 2005, TransCanada acquired the hydroelectric generation assets from USGen with a total generating capacity of 567 MW for US$503 million.

In January 2005, the 90 MW Grandview natural gas-fired cogeneration plant located in Saint John, New Brunswick was commissioned and placed in service.

Construction continued on the 550 MW Bécancour cogeneration plant and it is expected to be in service in late 2006.

The 739.5 MW Cartier Wind project awarded construction contracts in 2005. Construction on the first two projects is expected to commence early 2006 and the first project is scheduled to be commissioned in late 2006.

Plant Availability

Weighted average plant availability was 87 per cent in 2005, excluding Bruce Power, compared to 96 per cent in 2004.

Including Bruce Power, weighted average plant availability was 84 per cent in 2005, compared to 90 per cent in 2004.

BEAR CREEK An 80 MW natural gas-fired cogeneration plant located near Grande Prairie, Alberta.

MACKAY RIVER A 165 MW natural gas-fired cogeneration plant located near Fort McMurray, Alberta.

REDWATER A 40 MW natural gas-fired cogeneration plant located near Redwater, Alberta.

SUNDANCE A&B The Sundance power facility in Alberta is the largest coal-fired electrical generating facility in Western Canada. TransCanada owns the 560 MW Sundance A PPA, ending in 2017. TransCanada effectively owns 50 per cent of the 706 MW Sundance B PPA, ending in 2020.

SHEERNESS In December 2005, TransCanada acquired the remaining rights and obligations of the 756 MW Sheerness PPA with a remaining term of 15 years. The plant consists of two coal-fired thermal power generating units.

CARSELAND An 80 MW natural gas-fired cogeneration plant located near Carseland, Alberta.

CANCARB The 27 MW Cancarb facility at Medicine Hat, Alberta is fuelled by waste heat from TransCanada's adjacent thermal carbon black facility.

BRUCE POWER At December 31, 2005, TransCanada owned 31.6 per cent of Bruce B, consisting of operating Units 5 to 8 with approximately 3,200 MW of generating capacity. In addition, TransCanada owned 47.9 per cent of Bruce A, consisting of operating Units 3 and 4 with approximately 1,500 MW of generating capacity and currently idle Units 1 and 2 with approximately 1,500 MW of generating capacity. Units 1 and 2 are currently being refurbished for expected restart of the first unit commencing in 2009.

OSP The OSP plant is a 560 MW natural gas-fired, combined-cycle facility in Rhode Island.

BÉCANCOUR The 550 MW Bécancour natural gas-fired cogeneration power plant located near Trois-Rivières, Québec is under construction and is expected to be in service in late 2006. The entire power output will be supplied to Hydro-Québec under a 20 year power purchase contract. Steam will also be sold to local businesses.

CARTIER WIND Cartier Wind, 62 per cent owned by TransCanada, is comprised of six wind projects totalling 739.5 MW to be commissioned between 2006 and 2012. Construction on the first two projects, with a combined generating capacity of 210 MW, is expected to commence early 2006 and the first project is expected to be in service in late 2006. The entire power output will be supplied to Hydro-Québec under a 20 year power purchase contract.

GRANDVIEW A 90 MW natural gas-fired cogeneration power plant located in Saint John, New Brunswick was commissioned and in service in January 2005. Under a 20 year tolling arrangement, 100 per cent of the plant's heat and electricity output is sold to Irving.

TC HYDRO In April 2005, TransCanada closed the acquisition of hydroelectric generation assets from USGen. These merchant assets have a total generating capacity of 567 MW and are located in New Hampshire, Vermont and Massachusetts.

POWER RESULTS-AT-A-GLANCE

Year ended December 31 (millions of dollars)

	2005	2004	2003
Bruce Power	**195**	130	99
Western operations	**123**	138	160
Eastern operations	**137**	108	127
Power LP investment	**29**	29	35
General, administrative, support costs and other	**(102)**	(89)	(86)
Operating and other income	**382**	316	335
Financial charges	**(11)**	(13)	(12)
Income taxes	**(118)**	(94)	(103)
	253	209	220
Gains related to Power LP and Paiton Energy (after tax)	**308**	187	
Net earnings	**561**	396	220

Power's net earnings in 2005 of $561 million increased $165 million compared to $396 million in 2004 primarily due to gains related to Paiton Energy and Power LP. In 2005, TransCanada sold its approximate 11 per cent interest in Paiton Energy to subsidiaries of The Tokyo Electric Power Company for gross proceeds of US$103 million ($122 million) resulting in an after-tax gain of $115 million. In August 2005, TransCanada sold its ownership interest in Power LP to EPCOR Utilities Inc. (EPCOR) for net proceeds of $523 million resulting in an after-tax gain of $193 million. Included in 2004 net earnings was an after-tax gain of $187 million comprised of a $15 million after-tax gain on the sale of TransCanada's Curtis Palmer and ManChief power facilities to Power LP as well as $172 million of after-tax dilution and other gains.

Excluding the Paiton Energy and Power LP-related gains in 2005 and 2004, respectively, Power's net earnings for the year ended December 31, 2005 of $253 million increased $44 million compared to $209 million in 2004. The increase was primarily due to higher operating and other income from Bruce Power and Eastern Operations, partially offset by a reduced contribution from Western Operations and higher general, administrative, support costs and other.

In 2003, Western Operations' results included a $31 million pre-tax ($19 million after tax) settlement with a former counterparty that defaulted in 2001 under power forward contracts. Power's net earnings for 2004, excluding gains related to Power LP in 2004 and the counterparty settlement in 2003, increased $8 million year-over-year. Pre-tax equity income from Bruce Power of $130 million in 2004 increased $31 million compared to TransCanada's period of ownership in 2003. This was partially offset by lower contributions from Eastern Operations and Power LP investment.

POWER PLANTS NOMINAL GENERATING CAPACITY AND FUEL TYPE

	MW	Fuel Type
Bruce Power[1]	2,450	Nuclear
Western operations		
Sheerness[2]	756	Coal
Sundance A[3]	560	Coal
Sundance B[3]	353	Coal
MacKay River	165	Natural gas
Carseland	80	Natural gas
Bear Creek	80	Natural gas
Redwater	40	Natural gas
Cancarb	27	Natural gas
	2,061	
Eastern operations		
TC Hydro[4]	567	Hydro
OSP	560	Natural gas
Bécancour[5]	550	Natural gas
Cartier Wind[6]	458	Wind
Grandview[7]	90	Natural gas
	2,225	
Total Nominal Generating Capacity	6,736	

(1) Represents TransCanada's 47.9 per cent proportionate interest in Bruce A and 31.6 per cent proportionate interest in Bruce B at December 31, 2005. Bruce A consists of four 750 MW reactors. Bruce A Unit 4 was returned to service in fourth quarter 2003. Bruce A Unit 3 was returned to service in first quarter 2004. Bruce A Units 1 and 2 are currently being refurbished and are expected to restart commencing in 2009. Bruce B consists of four reactors which are currently in operation, with a combined capacity of approximately 3,200 MW.

(2) TransCanada directly acquires 756 MW from Sheerness through a long-term PPA acquired in December 2005.

(3) TransCanada directly or indirectly acquires 560 MW from Sundance A and 353 MW from Sundance B through long-term PPAs, which represents 100 per cent of the Sundance A and 50 per cent of the Sundance B power plant output, respectively.

(4) Acquired in April 2005.

(5) Currently under construction.

(6) Currently under construction. Represents TransCanada's 62 per cent of 739.5 MW.

(7) Placed in-service in January 2005.

POWER FINANCIAL ANALYSIS

Bruce Power

On October 31, 2005, Bruce Power and the OPA completed a long-term agreement whereby Bruce A will restart and refurbish the currently idle Units 1 and 2, extend the operating life of Unit 3 by replacing its steam generators and fuel channels when required and replace the steam generators on Unit 4. As a result of the agreement between Bruce Power and the OPA, and Cameco's decision not to participate in the restart and refurbishment program, a new partnership was created. Bruce A subleases its facilities, which are comprised of Units 1 to 4, from Bruce B. TransCanada and BPC each incurred a net cash outlay of approximately $100 million on the formation of Bruce A. As

at December 31, 2005, TransCanada and BPC each owned a 47.9 per cent interest in Bruce A. The remaining 4.2 per cent is owned by the Power Worker's Union Trust No. 1 and The Society of Energy Professionals Trust. The day-to-day operations of the Bruce Power facilities are expected to be unaffected by the formation of Bruce A and TransCanada continues to own 31.6 per cent of the Bruce B Units 5 to 8.

Upon reorganizing, both Bruce A and Bruce B became jointly controlled entities and TransCanada proportionately consolidated these investments on a prospective basis from October 31, 2005. The following Bruce Power financial results reflect the operations of the full six-unit operation for all periods. The Bruce Power information below includes adjustments to eliminate the effect of certain intercompany transactions between Bruce A and Bruce B.

Bruce Power Results-at-a-Glance

Year ended December 31 (millions of dollars)

	2005	2004	2003
Bruce Power (100 per cent basis)			
Revenues			
Power	**1,907**	1,563	1,183
Other[1]	**35**	20	25
	1,942	1,583	1,208
Operating expenses			
Operations and maintenance	**(871)**	(793)	(608)
Fuel	**(77)**	(68)	(45)
Supplemental rent	**(164)**	(156)	(111)
Depreciation and amortization	**(198)**	(161)	(89)
	(1,310)	(1,178)	(853)
Operating income	**632**	405	355
Financial charges under equity accounting to October 31, 2005	**(58)**	(67)	(69)
	574	338	286
TransCanada's proportionate share	**188**	107	65
Adjustments	**7**	23	34
TransCanada's operating and other income from Bruce Power[2]	**195**	130	99
Bruce Power Other Information			
Plant availability	**80%**	82%	83%
Sales volumes (GWh)[3]			
Bruce Power 100 per cent	**32,900**	33,600	21,060
TransCanada's proportionate share	**10,732**	10,608	6,655
Results per MWh[4]			
Power revenues	**$58**	$47	$48
Fuel	**$2**	$2	$2
Total operating expenses[5]	**$40**	$35	$36
Percentage of output sold to spot market	**49%**	52%	35%

(1) Includes fuel cost recoveries for Bruce A of $4 million for 2005.

(2) TransCanada's consolidated equity income includes $168 million which represents TransCanada's 31.6 per cent share of Bruce Power earnings for the ten months ended October 31, 2005. TransCanada acquired a 31.6 per cent interest in Bruce B in February 2003, which

at the time owned the currently idle Bruce A Units 1 and 2 as well as the currently operating Bruce A Units 3 and 4 and Bruce B Units 5 to 8.

(3) Gigawatt hours.

(4) Megawatt hours.

(5) Net of cost recoveries.

TransCanada's operating and other income from its combined investment in Bruce Power for 2005 was $195 million compared to $130 million for 2004. The increase of $65 million was primarily due to higher realized prices in 2005 and was offset in part by higher maintenance costs, higher depreciation and lower capitalization of labour and other in-house costs following the restart of Unit 3 in first quarter 2004. Adjustments to TransCanada's combined interest in Bruce Power's income before income taxes for 2005 were lower than in 2004 primarily due to a lower amortization of the purchase price allocated to the fair value of sales contracts in place at the time of acquisition in 2003.

Combined Bruce Power prices achieved during 2005 (excluding Bruce cost recoveries) were $58 per MWh compared to $47 per MWh in 2004 reflecting higher prices on uncontracted volumes sold into the spot market. Bruce Power's combined operating expenses (net of cost recoveries) increased to $40 per MWh for 2005 from $35 per MWh in 2004. This was primarily the result of one additional planned maintenance outage in 2005 compared to 2004 as well as higher maintenance costs, higher depreciation and lower capitalization of labour and other in-house costs following the restart of Unit 3.

The Bruce units ran at a combined average availability of 80 per cent in 2005, compared to an 82 per cent average availability during 2004. The lower availability in 2005 was the result of 67 additional days of planned maintenance outages plus an additional 45 forced outage days in 2005 as compared to 2004. The additional forced outage days in 2005 are due in large part to a 27 day forced outage that occurred as a result of a transformer fire at Unit 6.

TransCanada's operating and other income from its combined investment in Bruce Power for 2004 was $130 million compared to $99 million for 2003. This increase was primarily due to higher output in 2004 as a result of the return to service of Units 3 and 4 as well as a full year of earnings in 2004 on Units 5 to 8 compared to earnings from February 14 to December 31 in 2003, reflecting TransCanada's period of ownership in 2003. Adjustments to TransCanada's interest in Bruce Power income before taxes for 2004 were lower than the same period in 2003 primarily due to the cessation of interest capitalization upon the return to service of Units 3 and 4.

Income from Bruce B is directly impacted by fluctuations in wholesale spot market prices for electricity and income from both Bruce A and Bruce B units is impacted by overall plant availability, which in turn, is impacted by scheduled and unscheduled maintenance. To reduce its exposure to spot market prices, Bruce B had, as at December 31, 2005, entered into fixed price sales contracts to sell forward approximately 13,000 GWh hours of 2006 output and approximately 3,600 GWh of 2007 output. As a result of the contract with the OPA, all of the output from Bruce A will be sold at a fixed price of $57.37 per MWh, adjusted annually on April 1 for inflation, before recovery of fuel costs from the OPA. Under the terms of the arrangement between Bruce A and the OPA, effective October 31, 2005, Bruce A receives a contract price for power generated, where the price is adjusted for inflation annually on April 1 and capital cost variances associated with the restart and refurbishment project but will not vary with changes in the wholesale price of power in the Ontario market. As part of this contract, sales from the Bruce B Units 5 to 8 are subject to a floor price of $45 per MWh, adjusted annually for inflation on April 1. Receipts by Bruce Power under this floor price mechanism are refundable if prices subsequently increase above the floor price.

The overall plant availability percentage in 2006 is expected to be in the low 90s for the four Bruce B units and the low 80s for the two operating Bruce A units. A planned outage on Bruce A Unit 3 is scheduled to last approximately one month during first quarter 2006 and a two month maintenance outage of Bruce A Unit 4 is expected to commence in second quarter 2006. The only planned maintenance outage for 2006 for Bruce B is an approximate two month outage scheduled for Unit 8 beginning in third quarter 2006.

In 2005, cash distributions to partners, excluding a special distribution, were $400 million of which TransCanada's share was $126 million. No distributions were made to partners in 2004. The partners have agreed that all excess cash from both Bruce A and Bruce B will be distributed on a monthly basis and that separate cash calls will be made for major capital projects, including the Bruce A restart and refurbishment project.

Bruce A's capital program for the restart and refurbishment project is expected to total approximately $4.25 billion and TransCanada's approximate $2.125 billion share will be financed through capital contributions to 2011. A capital cost risk and reward sharing schedule with OPA is in place for spending below or in excess of the $4.25 billion base case estimate. Work to refurbish Units 1 and 2 has commenced with the first unit expected to be online in 2009, subject to approval by the Canadian Nuclear Safety Commission. Restarting Units 1 and 2, which have a combined capacity of approximately 1,500 MW, will boost the Bruce facilities' overall output to more than 6,200 MW. As at December 31, 2005, Bruce A had capitalized $324 million with respect to the restart and refurbishment project.

Western Operations

Western Operations Results-at-a-Glance[1]

Year ended December 31 (millions of dollars)

	2005	2004	2003
Revenues			
Power	**715**	606	688
Other[2]	**158**	120	112
	873	726	800
Cost of sales			
Power	**(476)**	(377)	(442)
Other[3]	**(104)**	(64)	(71)
	(580)	(441)	(513)
Other costs and expenses	**(149)**	(125)	(98)
Depreciation	**(21)**	(22)	(29)
Operating and other income	**123**	138	160

(1) ManChief is included until April 30, 2004.

(2) Includes Cancarb Thermax and natural gas sales.

(3) Includes the cost of natural gas sold.

Western Operations Sales Volumes[1]

Year ended December 31 (GWh)

	2005	2004	2003
Supply			
Generation	**2,245**	2,105	2,010
Purchased			
Sundance A & B PPAs	**6,974**	6,842	6,959
Other purchases	**2,687**	2,748	3,327
	11,906	11,695	12,296
Contracted vs. Spot			
Contracted	**10,374**	10,705	11,039
Spot	**1,532**	990	1,257
	11,906	11,695	12,296

(1) ManChief is included until April 30, 2004.

As at December 31, 2005, Western Operations directly controlled approximately 2,100 MW of power supply in Alberta from its three long-term PPAs and five natural gas-fired cogeneration facilities. The Western Operations power supply portfolio is now comprised of approximately 1,700 MW of low-cost, base-load coal-fired generation supply and approximately 400 MW of natural gas-fired cogeneration assets. This supply portfolio is among the lowest-cost, most competitive generation in the Alberta market area. The three long-term PPAs include the December 2005 acquisition of the remaining rights and obligations of the 756 MW Sheerness PPA in addition to the Sundance A and Sundance B PPAs acquired in 2001 and 2002, respectively. The Sheerness PPA was acquired from the Alberta Balancing Pool for $585 million and has a remaining term of approximately 15 years. The PPAs entitle TransCanada to the output capacity of these coal facilities, ending in 2017 to 2020.

The focus of Western Operations is to maximize the value of its power supply portfolio through a balanced portfolio of long- and short-term power sale contracts. The focus is also on expanding its power supply portfolio though acquisitions and optimizing the value and output from its existing generation assets. The success of Western Operations is the direct result of its two integrated functions marketing and plant operations.

The marketing function, based in Calgary, Alberta, purchases and resells electricity sourced from the PPAs, markets uncommitted generation volumes from the cogeneration facilities and purchases and resells power and natural gas to maximize the value of the cogeneration facilities. The marketing function is integral to optimizing Power's return from its portfolio of power supply and managing risks around uncontracted volumes. The intention for the Sheerness output is the same as the Sundance output, whereby a significant portion of the power supply is expected to be sold under long-term contract to the extent possible in the market. The majority of the expected output from the cogeneration plants is also sold under long-term contract. Some portion of power supply from the PPAs and the cogeneration assets is intentionally not committed under long-term sales contracts to assist in managing Power's overall portfolio of generation. This approach to portfolio management assists in minimizing costs in situations where Power would otherwise have to purchase power in the open market to fulfill its contractual obligations. In 2005, approximately 13 per cent of power sales volumes were sold into the spot market. To reduce exposure to spot market prices of uncontracted volumes, as at December 31, 2005, Western Operations had fixed price sale contracts to sell forward approximately 9,800 GWh for 2006 and 6,000 GWh for 2007.

Plant operations consist of five natural gas-fired cogeneration power plants located in Alberta with an approximate combined output capacity of 400 MW ranging from 27 MW to 165 MW per facility. A majority of the expected output is sold under long-term contracts and the remainder is subject to fluctuations in the price of power and natural gas. Market heat rates in Alberta in 2005 were at historic lows earlier in the year but improved substantially by year-end. Market heat rate is determined by dividing the average price of power per MWh by the average price of natural gas per gigajoule (GJ) for a given period. To the extent power is not sold under long-term contract and plant fuel-gas has not been purchased, the higher the market heat rate, the more profitable is a natural gas-fired generating facility. Market heat rates averaged approximately 8.3 GJ/MWh in 2005 compared to approximately 8.8 GJ/MWh in 2004. All plants, except the 80 MW Bear Creek facility located near Grand Prairie, operated with an average plant availability in 2005 of approximately 93 per cent.

Bear Creek experienced an unplanned outage in 2005 resulting from technical difficulties with its gas turbine in the early part of 2005 and the facility has remained on an unplanned outage since May 31, 2005. Technical evaluation continued throughout 2005 regarding a possible long-term solution and the asset is expected to be back in service by mid-2006.

Operating and other income for 2005 was $123 million or $15 million lower compared to $138 million earned in 2004. This decrease was primarily due to reduced margins in 2005 resulting from the lower market heat rates on uncontracted volumes of power generated, fee revenues earned in 2004 from Power LP and a lower contribution from Bear Creek. Revenues and cost of sales increased in 2005 compared to 2004 primarily due to higher realized prices. Other costs and expenses, which include fuel gas consumed in generation, increased due to higher operating and fuel usage costs at MacKay River resulting from a full year of operation and higher natural gas prices. Generation volumes in 2005 increased compared to 2004 primarily due to a full year of operations at MacKay River partially offset by the unplanned outage at Bear Creek. The potential to earn fees to manage and operate Power LP's plants was eliminated with the sale of Power LP to EPCOR in August 2005. In 2005, approximately 13 per cent of power sales volumes were sold into the spot market compared to eight per cent in 2004.

Operating and other income in 2004 of $138 million was $22 million lower than the $160 million earned in 2003. The decrease was mainly due to a positive $31 million pre-tax settlement in June 2003 with a former counterparty that defaulted in 2001 under power forward contracts, as well as reduced income from ManChief following the sale of the plant to Power LP in April 2004. Partially offsetting these decreases were contributions from the MacKay River plant which was placed in service in 2004, fees earned with respect to Power LP's asset acquisitions in 2004 and the impact of higher net margins achieved in second and third quarter 2004 on the overall portfolio.

Eastern Operations

Eastern Operations Results-at-a-Glance[1]

Year ended December 31 (millions of dollars)

	2005	2004	2003
Revenues			
Power	**505**	535	608
Other[2]	**412**	238	200
	917	773	808
Cost of sales			
Power	**(215)**	(288)	(281)
Other[2]	**(373)**	(211)	(185)
	(588)	(499)	(466)
Other costs and expenses	**(167)**	(146)	(186)
Depreciation	**(25)**	(20)	(29)
Operating and other income	**137**	108	127

(1) Curtis Palmer is included until April 30, 2004.

(2) Other includes natural gas.

Eastern Operations Sales Volumes[1]

Year ended December 31 (GWh)

	2005	2004	2003
Supply			
Generation	**2,879**	1,467	1,871
Purchased	**2,627**	4,731	5,035
	5,506	6,198	6,906
Contracted vs. Spot			
Contracted	**4,919**	6,055	6,678
Spot	**587**	143	228
	5,506	6,198	6,906

(1) Curtis Palmer is included until April 30, 2004.

Eastern Operations conducts its business primarily in the Northeastern U.S. and Eastern Canada markets and excludes Bruce Power. In the New England market, Eastern Operations has established a successful marketing operation and, in 2005, acquired a significant group of hydroelectric generation assets from USGen with generation capacity of 567 MW. In Eastern Canada, construction continued on the 550 MW Bécancour natural gas-fired plant in Québec and the 90 MW Grandview cogeneration facility was placed into service on January 1, 2005. In late 2005, development plans were finalized and construction is expected to commence early 2006 on the first two of six wind farm projects, with generating capacity of 210 MW of the 739.5 MW Cartier Wind projects in Québec. Including facilities that are under construction or in development, Eastern Operations owns more than 2,200 MW of power generation capacity.

Eastern Operations' success in the New England deregulated power markets is the direct result of a knowledgeable, region-specific marketing operation which is conducted through its wholly-owned subsidiary, TransCanada Power Marketing Limited (TCPM), located in Westborough, Massachusetts. TCPM has firmly established itself as a leading energy provider and marketer and is focused on selling power under short- and long-term contracts to wholesale, commercial and industrial customers while managing a portfolio of power supplies sourced from both its own generation and wholesale power purchases. To reduce its exposure to spot market prices, as at December 31, 2005, Eastern Operations had entered into fixed price sales contracts to sell approximately 5,000 GWh of power for 2006 and approximately 3,500 GWh of power for 2007, although certain contracted volumes are dependent on customer usage levels. TCPM is a full requirement electricity service provider offering varied products and services to assist customers in managing their power supply and power prices in volatile deregulated power markets.

Eastern Operations' operating power generation assets currently consist of TC Hydro, Ocean State Power (OSP) and Grandview.

The TC Hydro assets, acquired on April 1, 2005, include 13 hydroelectric stations housing 39 generating units on the Connecticut River System in New Hampshire and Vermont, and the Deerfield River System in Massachusetts and Vermont. These facilities were integrated into TransCanada in 2005. Water flows in 2005 through the hydro assets were above the long-term average as a result of higher precipitation in the areas surrounding the river systems.

OSP is a 560 MW natural gas-fired plant located in Rhode Island. In 2005, OSP was successful in restructuring its long-term natural gas fuel supply contracts with its suppliers. The contract restructuring at OSP reduced the term of the long-term natural gas supply contracts by approximately three years (currently ending in October 2008) and adjusted the pricing to track spot market pricing of natural gas at the Niagara delivery point versus the previously arbitrated pricing that had resulted in an above-market cost of natural gas for OSP. The new contracts, for approximately 100,000 GJ per day, require OSP to take delivery of the natural gas irrespective of the fuel requirements at the plant. OSP experienced an unplanned outage for most of the first half of 2005 resulting from a failure of one of the steam turbines at the plant. This unit was returned to service in mid-2005; however, due to the nature of the failure, the second steam turbine at OSP was taken out of service to undertake repairs and was returned to service in January 2006. An insurance claim has been filed in respect of this incident, including a claim for business interruption coverage. This claim is currently under discussion with the insurers.

Grandview is a 90 MW natural gas-fired cogeneration facility on the site of the Irving refinery in Saint John, New Brunswick. The Grandview facility was commissioned in January 2005. Under a 20 year tolling arrangement, Irving supplies fuel for the plant and contracts for 100 per cent of the plant's heat and electricity output.

Eastern Operations emerging presence in Eastern Canada is represented by the development and construction in 2006 of the 550 MW natural gas-fired Bécancour plant and the first two of six wind farms of the Cartier Wind project. The first of the two wind farms is expected to be in service in late 2006. Bécancour is expected to be operational in late 2006. Bécancour and Cartier Wind are located in Québec.

Operating and other income for 2005 was $137 million or $29 million higher than the $108 million earned in 2004. Incremental income from the acquisition of the TC Hydro assets and income from the Grandview cogeneration facility were the primary reasons for this increase. Partially offsetting these increases were a $16 million pre-tax ($10 million after tax) contract restructuring payment made by OSP to its natural gas fuel suppliers in first quarter 2005, a $16 million pre-tax ($10 million after tax) reduction in income as a result of the sale of Curtis Palmer to Power LP in April 2004, and a loss of operating income primarily associated with the expiration of certain long-term sales contracts in 2004.

Eastern Operations' power revenues decreased in 2005 primarily due to lower long-term sales volumes resulting from the expiration of certain contracts at the end of 2004. Partially offsetting this were higher realized prices in 2005. Other revenue and other cost of sales increased year-over-year as a result of natural gas purchased and resold under the new

natural gas supply contracts at OSP. Cost of sales for power were lower in 2005 due to the impact of lower purchased volumes partially offset by higher prices for purchased power. Purchased power volumes were lower in 2005 due to lower contracted sales volumes and the incremental power generation from the purchase of the TC Hydro assets. Volumes generated from the TC Hydro assets reduced the requirement to purchase power to fulfill contractual sales obligations. Other costs and expenses in 2005 were higher primarily due to the acquisition of the TC Hydro assets.

Operating and other income for 2004 was $108 million or $19 million lower than the $127 million earned in 2003. This decrease was mainly due to a reduction in income as a result of the sale of the Curtis Palmer hydroelectric facilities to Power LP in April 2004, the unfavourable impact of higher natural gas fuel costs at OSP and a weaker U.S. dollar in 2004. Partially offsetting these decreases was a $16 million positive impact from the restructuring transaction related to the power purchase contracts in 2004 between OSP and Boston Edison Company (Boston Edison). TransCanada recognized earnings from the transaction's effective date of April 1, 2004.

Power LP Investment

On August 31, 2005, TransCanada closed the sale of all of its interest in Power LP to EPCOR for net proceeds of $523 million resulting in an after-tax gain of $193 million. This divestiture included approximately 14.5 million Partnership units, representing approximately 30.6 per cent of the outstanding units, 100 per cent ownership of the general partner of Power LP, and management and operations agreements governing the ongoing operation of Power LP's generation assets. TransCanada's investment in Power LP generated operating and other income of $29 million in 2005 compared to $29 million and $35 million in 2004 and 2003, respectively.

Weighted Average Plant Availability[1]

	2005	2004	2003
Bruce Power[2]	80%	82%	83%
Western operations[3]	85%	95%	93%
Eastern operations[3][4]	83%	95%	94%
Power LP investment[3][5]	94%	97%	96%
All plants, excluding Bruce Power	87%	96%	94%
All plants	84%	90%	90%

(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) Unit 3 is included effective March 1, 2004 and Unit 4 is included effective November 1, 2003.

(3) ManChief and Curtis Palmer are included in Power LP Investment effective April 30, 2004.

(4) TC Hydro is included in Eastern Operations effective April 1, 2005.

(5) Power LP is included to August 31, 2005.

Weighted average plant availability, excluding Bruce Power, was 87 per cent in 2005 compared to 96 per cent in 2004. Western Operations' weighted average plant availability was impacted in 2005 by an unplanned outage at Bear Creek

and a planned outage at MacKay River. In 2005, Eastern Operations experienced two significant outages at OSP. The first outage was completed in mid-2005 and the second outage was completed in January 2006.

POWER OPPORTUNITIES AND DEVELOPMENTS

TransCanada is committed to growing the Power business through acquisitions and development of greenfield opportunities in markets it knows and where it has a competitive advantage primarily Western Canada, Eastern Canada and the Northeastern U.S. The North American power industry is expansive and will provide many opportunities for greenfield growth in power generation and power infrastructure projects. In addition to greenfield growth opportunities, TransCanada will continue to pursue acquisitions of additional power assets, including opportunities resulting from, amongst other things, industry and corporate restructurings and corporate bankruptcies. Power's diverse power supply portfolio will continue to include low-cost, base-load facilities with low operating costs and high reliability and/or be underpinned by secure long-term contracts.

The Cartier Wind project is scheduled to commercially place in service the first of six wind farms in 2006. The remaining five wind farms are expected to be placed in service between 2007 and 2012. The Bécancour natural gas-fired cogeneration power plant is expected to be in service in late 2006. Bruce Power will continue refurbishment of the currently idle Bruce A Units 1 and 2 for expected restart commencing in 2009.

In February 2006, the Ontario Energy Minister directed the OPA to move forward to negotiate the terms for the construction of the 550 MW Portlands Energy Centre (PEC) in downtown Toronto. TransCanada has a 50 per cent interest in PEC through a partnership with Ontario Power Generation.

POWER BUSINESS RISKS

Plant Availability

Maintaining plant availability is critical to the continued success of the Power business and this risk is mitigated through a commitment to an operational excellence model that provides low-cost, reliable operating performance at each of the company's power plants. This same commitment to operational excellence will be applied in 2006 and future years. However, unexpected plant outages and/or the duration of outages could result in lower sales revenue, reduced margins, increased maintenance costs and may require power purchases at market prices to enable TransCanada to meet the company's contractual power supply obligations.

Fluctuating Market Prices

TransCanada operates in highly competitive, deregulated power markets. Volatility in electricity prices is caused by market factors such as power plant fuel costs, fluctuating supply and demand which are greatly affected by weather, power consumption and plant availability. TransCanada manages these inherent market risks through:

- long-term purchase and sales contracts for both electricity and plant fuels;
- control of generation output;
- matching physical plant contracts or PPA supply with customer demand;
- fee-for-service managed accounts rather than direct commodity exposure; and
- the company's overall risk management program with respect to general market and counterparty risks.

The company's risk management practices are described further in the section on "Risk Management". See the section below "Power Business Risks Uncontracted Volumes".

Weather

Extreme temperature and weather events often affect power and natural gas demand and create price volatility, and may also impact the ability to transmit power to markets. Seasonal changes in temperature also affect the efficiency and output capability of natural gas-fired power plants.

Hydrology

Power is subject to hydrology risk with its ownership of hydroelectric power generation facilities in the Northeastern U.S. Climate changes, weather events, local river management and potential dam failures at these plants or upstream facilities pose potential risks to the company.

Uncontracted Volumes

Sale of uncontracted power in the open market is subject to market price volatility which directly impacts earnings. TransCanada has uncontracted sales volumes in both its Eastern Operations and Western Operations. In addition, with the acquisition of the Sheerness PPA in late 2005, Western Operations significantly increased its level of uncontracted sales volumes which are subject to price volatility in the Alberta wholesale marketplace. Although TransCanada seeks to generally secure sales under medium- to long-term contracts, TransCanada retains an amount of unsold generation in the short term in order to provide flexibility in managing the company's portfolio of owned assets. Also, Bruce B has a significant amount of uncontracted volumes sold into the wholesale spot market, although 100 per cent of the Bruce A output will be sold to the OPA under fixed price contract terms. Sales from the Bruce B Units 5 to 8 are subject to a floor price of $45 per MWh, adjusted annually for inflation on April 1.

Execution and Capital Cost

TransCanada, including its investment in Bruce Power, is subject to execution and capital cost risk. Bruce A's four unit restart and refurbishment program is subject to execution and capital cost risk. Bruce A and the OPA share capital costs that are above and below $4.25 billion on a 50/50 basis for cost overruns up to $618 million and 75/25 for any additional cost overruns. Similarly, Bruce A and OPA share 50/50 in cost benefits if costs are $240 million less than expected and 75/25 on the next $150 million of savings.

Regulatory

TransCanada operates in both regulated and deregulated power markets. As electricity markets evolve across North America, there is the potential for regulatory bodies to implement new rules that could negatively impact TransCanada as a generator and marketer of electricity. These may be in the form of market rule changes, price caps, emission controls, unfair cost allocations to generators or attempts to control the wholesale market by encouraging new plant construction. TransCanada continues to monitor regulatory issues and reform as well as participate in and lead discussions around these topics.

Foreign Exchange

TransCanada's earnings from Northeastern U.S. Operations are generated in U.S. dollars. The performance of the Canadian dollar relative to the U.S. dollar would either positively or negatively impact Power's net earnings, although this impact is mitigated by offsetting exposures in certain of TransCanada's other businesses as well as through the company's hedging activities.

POWER OTHER

Operational Excellence

TransCanada's sale of Power LP to EPCOR allowed it to focus on larger, directly owned power assets. TC Hydro was effectively integrated in 2005 while maintaining high levels of operating performance. TransCanada continues its commitment to an operational excellence strategy of providing low cost, reliable performance.

POWER OUTLOOK

Net earnings from Bruce Power are expected to be higher in 2006 as a result of higher generation volumes of output from fewer planned outages and TransCanada's increased ownership in Bruce A. Bruce B earnings are subject to variability as a result of prices realized, and both Bruce A and Bruce B results are impacted by plant availability and operating expense levels. The overall plant availability percentage in 2006, for planning purposes, is expected to be in the low 90s for the four Bruce B units and in the low 80s for the two operating Bruce A units.

The contribution from Western Operations is expected to be higher in 2006 primarily due to the December 2005 acquisition of the Sheerness PPA. At December 31, 2005 a significant portion of the acquired generation from Sheerness was uncontracted. The intention for marketing the Sheerness output is the same as the Sundance output, whereby a significant portion of the power supply is expected to be sold under long-term contract, providing this is possible in the market. The repair of Bear Creek is a high priority in 2006 and management expects the facility to be back in service in mid-2006.

The contribution from Eastern Operations is expected to rise slightly in 2006 compared to 2005 due to a full year of ownership of the TC Hydro assets and the expected commercial in-service of Bécancour and the first of the Cartier wind farms in late 2006.

The loss of earnings resulting from the sale of Power LP in August 2005 will partially offset these impacts.

Earnings opportunities in Power may be affected by factors such as plant availability, fluctuating market prices for power and natural gas and ultimately market heat rates, regulatory changes, weather, sales of uncontracted volumes, currency movements and overall stability of the power industry. See "Power Business Risks" for a complete discussion of these factors.

CORPORATE

CORPORATE RESULTS-AT-A-GLANCE

Year ended December 31 (millions of dollars)

	2005	2004	2003
Indirect financial charges and non-controlling interests	130	79	89
Interest income and other	(29)	(34)	(21)
Income taxes	(65)	(43)	(27)
Net expenses, after tax	36	2	41

Corporate reflects net expenses not allocated to specific business segments, including:

Indirect Financial Charges and Non-Controlling Interests Direct financial charges are reported in their respective business segments and are primarily associated with the debt and preferred securities related to the company's Wholly-Owned Pipelines. Indirect financial charges, including the related foreign exchange impacts, primarily reside in Corporate. These costs are directly impacted by the amount of debt that TransCanada maintains and the degree to which TransCanada is impacted by fluctuations in interest rates and foreign exchange.

Interest Income and Other Interest income is primarily earned on invested cash balances. Gains and losses on foreign exchange related to working capital in Corporate are included in interest income and other.

Income Taxes These include income taxes on corporate net expenses and income tax refunds and adjustments.

Net expenses, after tax, in Corporate were $36 million in 2005 compared to $2 million in 2004 and $41 million in 2003.

The increase of $34 million in net expenses in 2005 compared to 2004 was primarily due to increased interest expense on higher average long-term debt and commercial paper balances in 2005 as well as the release in 2004 of previously established restructuring provisions. Income tax refunds and positive tax adjustments were comparable in 2004 and 2005.

The decrease of $39 million in net expenses in 2004 compared to 2003 was primarily due to the positive impacts of income tax related items, including refunds received and the recognition of income tax benefits relating to additional loss carryforwards utilized, the release in 2004 of previously established restructuring provisions and positive impacts of foreign exchange related items.

In 2006, Corporate is expected to incur higher net expenses compared to 2005 primarily due to the income tax refunds and positive income tax adjustments recorded in 2005 that are not currently expected to recur in 2006. In addition, Corporate's results in 2006 could be impacted by debt levels, interest rates, foreign exchange movements and income tax refunds and adjustments. The performance of the Canadian dollar relative to the U.S. dollar would either positively or negatively impact Corporate's results, although this impact is mitigated by offsetting exposures in certain of TransCanada's other businesses as well as through the company's hedging activities.

LIQUIDITY AND CAPITAL RESOURCES

HIGHLIGHTS

Investing Activities

Total capital expenditures and acquisitions, including assumed debt, were approximately $6.0 billion over the past three years.

Dividend

TransCanada's Board of Directors has increased quarterly common share dividend payments for the past six consecutive years, including a five per cent increase to $0.32 per share from $0.305 per share for the quarter ending March 31, 2006.

Funds Generated from Operations

Funds generated from operations were approximately $2.0 billion for 2005 compared to approximately $1.7 billion and $1.8 billion, for 2004 and 2003, respectively. The Gas Transmission business was the primary source of funds generated from operations for each of the three years. As a result of rapid growth in the Power business in the last few years, the Power segment's funds generated from operations increased in 2005 compared to the two prior years. The decrease in 2004 compared to 2003 was mainly a result of higher current income tax expense in 2004 compared to 2003.

At December 31, 2005, TransCanada's 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, was consistent with recent years.

Investing Activities

Capital expenditures, excluding acquisitions, totalled $754 million in 2005 compared to $530 million in 2004 and $395 million in 2003, respectively. Expenditures in all three years related primarily to construction of new power plants in Canada and maintenance and capacity capital in TransCanada's Gas Transmission business.

During 2005, TransCanada acquired the remaining rights and obligations of the Sheerness PPA for $585 million, invested a net cash outlay of $100 million in Bruce A as part of the Bruce Power reorganization, purchased the TC Hydro assets for US$503 million and acquired an additional 3.5 per cent ownership interest in Iroquois Gas Transmission System L.P. for US$14 million. In 2005, TransCanada sold its ownership interest in Power LP for proceeds of $444 million, net of current tax, its approximate 11 per cent ownership interest in Paiton Energy for proceeds of $125 million, net of current tax, and PipeLines LP units for proceeds of $102 million, net of current tax. During 2004, TransCanada acquired GTN for US$1.2 billion, excluding assumed debt of approximately US$0.5 billion, and sold the ManChief and Curtis Palmer power facilities to Power LP for US$402.6 million, excluding closing adjustments.

During 2003, TransCanada acquired a 31.6 per cent interest in Bruce Power for $409 million, the remaining interests in Foothills previously not held by the company for $105 million, excluding assumed debt of $154 million, and increased its interest in Portland to 61.7 per cent from 33.3 per cent for US$51 million, excluding assumed debt of US$78 million.

Financing Activities

In 2005, TransCanada retired long-term debt of $1,113 million. In June 2005, Gas Transmission Northwest Corporation (GTNC) redeemed all of its outstanding US$150 million 7.80 per cent Senior Unsecured Debentures (Debentures). As a consequence, upon application by GTNC, the Debentures were de-listed from the New York Stock Exchange and GTNC no longer has any securities registered under U.S. securities laws. In June 2005, GTNC completed a US$400 million multi-tranche private placement of senior debt with a weighted average interest rate of 5.28 per cent and weighted average life of approximately 18 years. In 2005, TransCanada also issued $300 million of 5.10 per cent medium-term notes due 2017 under the company's Canadian shelf prospectus. The company increased its notes payable by $416 million during 2005.

In 2004, TransCanada retired long-term debt of $1,005 million. The company issued $200 million of 4.10 per cent medium-term notes due 2009, US$350 million of 5.60 per cent senior unsecured notes due 2034 and US$300 million of 4.875 per cent senior unsecured notes due 2015. The company increased its notes payable by $179 million during 2004.

In 2003, TransCanada repaid long-term debt of $753 million, reduced notes payable by $62 million and redeemed all of its outstanding US$160 million, 8.75 per cent Junior Subordinated Debentures. The company issued $450 million of ten year, 5.65 per cent medium-term notes and US$350 million of ten year, 4.00 per cent senior unsecured notes.

Dividends on common shares of $586 million were paid in 2005 compared to $552 million in 2004 and $510 million in 2003.

In January 2006, TransCanada's Board of Directors approved an increase in the quarterly common share dividend payment to $0.32 per share from $0.305 per share for the quarter ending March 31, 2006. This was the sixth consecutive year of dividend increase since the $0.20 per share declared for fourth quarter 2000, which represents a 60 per cent increase in per share dividends since 2000.

Certain terms of the preferred shares, preferred securities and debt instruments of TransCanada PipeLines Limited (TCPL), a wholly-owned subsidiary of TransCanada, could restrict TCPL's ability to declare dividends on preferred and common shares. At December 31, 2005, under the most restrictive provisions, approximately $1.6 billion was available for the payment of dividends on TCPL's common shares which are held 100 per cent by TransCanada.

Financing activities included a net reduction in TransCanada's proportionate share of non-recourse debt of joint ventures of $42 million in 2005 compared to a net increase of $105 million in 2004 and a net decrease of $12 million in 2003.

Credit Activities

At December 31, 2005, TCPL had shelf prospectuses that qualified for issuance $1.2 billion of medium-term notes in Canada and US$1 billion of debt securities in the U.S. In January 2006, $300 million of 4.3 per cent medium-term notes due 2011 were issued under the Canadian shelf prospectus.

At December 31, 2005, total credit facilities of $2.0 billion were available to support the company's commercial paper program and for general corporate purposes. Of this total, $1.5 billion is a committed five-year term syndicated credit facility. The facility is extendible on an annual basis and is revolving. In December 2005, the maturity date of this facility was extended to December 2010. The remaining amounts are either demand or non-extendible facilities.

At December 31, 2005, TransCanada had used approximately $271 million of its total lines of credit for letters of credit and to support ongoing commercial arrangements. If drawn, interest on the lines of credit would be charged at prime rates of Canadian chartered and U.S. banks or at other negotiated financial bases.

TransCanada's issuer rating assigned by Moody's Investors Service (Moody's) is A3 with a stable outlook. Credit ratings on TCPL's senior unsecured debt assigned by Dominion Bond Rating Service Limited (DBRS), 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.

CONTRACTUAL OBLIGATIONS

Obligations and Commitments

Total long-term debt at December 31, 2005 was approximately $10.0 billion compared to approximately $10.5 billion at December 31, 2004. TransCanada's share of total debt of joint ventures at December 31, 2005 was $978 million compared to $893 million at December 31, 2004. Total notes payable at December 31, 2005, including TransCanada's proportionate share of the notes payable of joint ventures, were $962 million compared to $546 million at December 31, 2004. The security provided by each joint venture, except the capital lease obligations at Bruce Power, is limited to the rights and assets of that joint venture and does not extend to the rights and assets of TransCanada, except to the extent of TransCanada's investment. TransCanada has provided certain pro-rata guarantees related to the capital lease obligations of Bruce Power.

Effective January 1, 2005, under new Canadian accounting standards, the non-controlling interest component of preferred securities was classified as long-term debt.

At December 31, 2005, scheduled principal repayments and interest payments related to long-term debt and the company's proportionate share of the long-term debt of joint ventures are as follows.

PRINCIPAL REPAYMENTS

Year ended December 31 (millions of dollars)

	2006	2007	2008	2009	2010	2011+
Long-term debt	393	604	547	742	416	7,331
Long-term debt of joint ventures	41	28	29	89	286	505
Total principal repayments	434	632	576	831	702	7,836

INTEREST PAYMENTS

Year ended December 31 (millions of dollars)

	2006	2007	2008	2009	2010	2011+
Interest payments on long-term debt	806	784	734	682	637	7,320
Interest payments on long-term debt of joint ventures	70	68	67	64	52	356
Total interest payments	876	852	801	746	689	7,676

At December 31, 2005, future annual payments, net of sub-lease receipts, under the company's operating leases for various premises, services, equipment and a natural gas storage facility are approximately as follows.

OPERATING LEASE PAYMENTS

Year ended December 31 (millions of dollars)

	2006	2007	2008	2009	2010	2011+
Minimum lease payments	46	52	54	54	53	646
Amounts recoverable under sub-leases	(12)	(12)	(12)	(11)	(11)	(13)
Net payments	34	40	42	43	42	633

The operating lease agreements for premises, services and equipment expire at various dates through 2011, with an option to renew certain lease agreements for five years. The operating lease agreement for the natural gas storage facility expires in 2030 with lessee termination rights every fifth anniversary commencing in 2010 and with the lessor having the right to terminate the agreement every five years commencing in 2015.

At December 31, 2005, the company's future purchase obligations are approximately as follows.

PURCHASE OBLIGATIONS[1]

Year ended December 31 (millions of dollars)

	2006	2007	2008	2009	2010	2011+
Gas Transmission						
Transportation by others[2]	179	175	131	89	79	52
Other	253	16	12	3		
Power						
Commodity purchases[3]	1,163	1,039	881	522	525	4,802
Capital expenditures[4]	534	390	145	70		
Other[5]	52	56	32	21	29	92
Corporate						
Information technology and other	16	14	14	14	7	14
Total purchase obligations	2,197	1,690	1,215	719	640	4,960

(1) The amounts in this table exclude funding contributions to pension plans and funding to the APG.

(2) Rates are based on known 2006 levels. Beyond 2006, demand rates are subject to change. The contract obligations in the table are based on known or contracted demand volumes only and exclude commodity charges incurred when volumes flow. Transportation by others is generally included in the revenue requirements of the regulated pipelines.

(3) Commodity purchases include fixed and variable components. The variable components are estimates and are subject to variability in plant production, market prices and regulatory tariffs.

(4) Amounts are estimates and are subject to variability based on timing of construction and project enhancements.

(5)

Includes estimates of certain amounts which are subject to change depending on plant fired hours, the consumer price index, actual plant maintenance costs, plant salaries as well as changes in regulated rates for transportation.

During 2006, TransCanada expects to make funding contributions to the company's pension plans and other benefit plans in the amount of approximately $95 million and $7 million, respectively. The expected increase in total funding in 2006 from $74 million in 2005 is due to continued reductions in discount rates used to calculate plan obligations partially offset by investment performance above long-term expectations in 2005. During 2006, TransCanada's proportionate share of expected funding contributions to be made by joint ventures to their respective pension plans and other benefit plans is approximately $27 million and $2 million, respectively.

Bruce Power

Included in Power's capital expenditures in the table above is TransCanada's share of Bruce A's signed commitments to third party suppliers for the next five years for the restart and refurbishment of the currently idle Units 1 and 2, extending the operating life of Unit 3 by replacing its steam generators and fuel channels when required and replacing the steam generators on Unit 4, as follows.

Year ended December 31 (millions of dollars)	
2006	322
2007	311
2008	142
2009	69
2010	
	844

Aboriginal Pipeline Group

On June 18, 2003, the Mackenzie Delta gas producers, the APG and TransCanada reached an agreement which governs TransCanada's role in the Mackenzie Gas Pipeline Project. The project would result in a natural gas pipeline being constructed from Inuvik, Northwest Territories, to the northern border of Alberta, where it would connect with the Alberta System. Under the agreement, TransCanada agreed to finance the APG for its one-third share of project development costs. These costs were originally estimated to be approximately $90 million, but given extended project delays, the protracted regulatory process and the projected timing to reach a decision to construct the pipeline, this share is currently forecast to increase to approximately $145 million. As at December 31, 2005, TransCanada had funded $87 million (2004 $60 million) of this loan which is included in other assets. The ability to recover this investment is dependent upon the outcome of the project.

TransCanada and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are or were transacted at market prices and in the normal course of business.

Guarantees

TransCanada had no outstanding guarantees related to the long-term debt of unrelated third parties at December 31, 2005.

The company, together with Cameco and BPC, has severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, operator licenses, the lease agreement, and contractor services. The terms of the guarantees currently range from 2018 to 2019.

As part of the reorganization of Bruce Power, including the formation of Bruce A and the commitment to restart and refurbish the Bruce A units, the company, together with BPC, severally guaranteed one-half of certain contingent financial obligations of Bruce A related to the refurbishment agreement with the OPA and cost sharing and sublease agreements with Bruce B. The terms of the guarantees range from 2019 to 2036.

TransCanada's share of the net exposure under these Bruce Power guarantees at December 31, 2005 was estimated to be approximately $652 million of a calculated maximum of $758 million. The current carrying amount of the liability related to these guarantees is nil and the fair value is approximately $17 million.

TransCanada has guaranteed the equity undertaking of a subsidiary which supports the payment, under certain conditions, of principal and interest on US$133 million of public debt obligations of TransGas. The company has a 46.5 per cent interest in TransGas. Under the terms of the agreement, the company severally with another major multinational company may be required to fund more than their proportionate share of debt obligations of TransGas in the event that the minority shareholders fail to contribute. Any payments made by TransCanada under this agreement convert into share capital of TransGas. The potential exposure is contingent on the impact of any change of law on TransGas' ability to service the debt. From the issuance of the debt in 1995 to date, there has been no change in applicable law and thus no exposure to TransCanada. The debt matures in 2010. The company has made no provision related to this guarantee.

In connection with the acquisition of GTN, US$241 million of the purchase price was deposited into an escrow account. As at December 31, 2005, there was US$54 million remaining in the escrow account. The outstanding funds in the escrow account represent the full face amount of the potential liability under certain GTN guarantees and are to be used to satisfy the liability of GTN under these designated guarantees.

Contingencies

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

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

FINANCIAL AND OTHER INSTRUMENTS

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

Derivatives and other instruments must be designated and effective to qualify for hedge accounting. Derivatives are recorded at their fair value at each balance sheet date. For cash flow and fair value hedges, gains or losses relating to derivatives are deferred and recognized in the same period and in the same financial statement category as the corresponding hedged transactions. For hedges of net investments in self-sustaining foreign operations, exchange gains or losses on derivatives, net of tax, and designated foreign currency denominated debt are offset against the exchange losses or gains arising on the translation of the financial statements of the foreign operations included in the foreign exchange adjustment account in Shareholders' Equity. In the event that a derivative does not meet the designation or effectiveness criteria, realized and unrealized gains or losses are recognized in income each period in the same financial statement category as the underlying transaction giving rise to the exposure being economically hedged. Premiums paid or received with respect to derivatives that are hedges are deferred and amortized to income over the term of the hedge.

If a derivative that previously qualified as a hedge is settled, de-designated or ceases to be effective, the gain or loss at that date is deferred and recognized in the same period and in the same financial statement category as the

corresponding hedged transactions. If a hedged anticipated transaction is no longer probable to occur, related deferred gains or losses are recognized in income in the current period.

The recognition of gains and losses on derivatives for Canadian Mainline, Alberta System, the Foothills System and the BC System exposures is determined through the regulatory process.

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

Net Investment in Foreign Operations

At December 31, 2005 and 2004, the company had net investments in self sustaining foreign operations with a U.S. dollar functional currency which created an exposure to changes in exchange rates. The company uses U.S. dollar denominated debt and derivatives to hedge this exposure on an after-tax basis. The fair value for derivatives used to manage the exposure is shown in the table below.

Asset/(Liability)

		2005		2004	
December 31 (millions of dollars)	Accounting Treatment	**Fair Value**	**Notional or Notional Principal Amount**	Fair Value	Notional or Notional Principal Amount
U.S. dollar cross-currency swaps (maturing 2006 to 2012)	Hedge	**119**	**U.S. 450**	95	U.S. 400
U.S. dollar forward foreign exchange contracts (maturing 2006)	Hedge	**5**	**U.S. 525**	(1)	U.S. 305
U.S. dollar options (maturing 2006)	Hedge		**U.S. 60**	1	U.S. 100

Reconciliation of Foreign Exchange Adjustment (Losses)/Gains

December 31 (millions of dollars)	**2005**	2004
Balance at January 1	**(71)**	(40)
Translation losses on foreign currency denominated net assets[(1)]	**(21)**	(39)
Gains on derivatives	**23**	52
Income taxes	**(21)**	(44)
Balance at December 31	**(90)**	(71)

(1) In 2005, includes gains of $80 million (2004 $101 million) related to foreign currency denominated debt designated as a hedge.

Foreign Exchange Gains/(Losses)

Foreign exchange gains included in Other Expenses/(Income) for the year ended December 31, 2005 are $19 million (2004 $6 million; 2003 nil).

Foreign Exchange and Interest Rate Management Activity

The company manages the foreign exchange and interest rate risks related to its U.S. dollar denominated debt, and transactions and interest rate exposures of the Canadian Mainline, the Alberta System and the BC System through the use of foreign currency and interest rate derivatives. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms. The details of the foreign exchange and interest rate derivatives are shown in the table below.

Asset/(Liability)

		2005		2004	
December 31 (millions of dollars)	Accounting Treatment	**Fair Value**	**Notional or Notional Principal Amount**	Fair Value	Notional or Notional Principal Amount
Foreign Exchange					
Cross- currency swaps (maturing 2010 to 2013)	Non-hedge	**(86)**	**363/U.S. 257**	(69)	363/U.S. 257
Interest Rate					
Interest rate swaps					
Canadian dollars (maturing 2007 to 2008)	Hedge	**4**	**100**	7	145
(maturing 2006 to 2009)	Non-hedge	**7**	**374**	9	374
		11		16	
U.S. dollars (maturing 2007 to 2009)	Non-hedge	**5**	**U.S. 100**	7	U.S. 100

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

Asset/(Liability)

		2005		2004	
December 31 (millions of dollars)	Accounting Treatment	**Fair Value**	**Notional or Notional Principal Amount**	Fair Value	Notional or Notional Principal Amount
Foreign Exchange					
Options (maturing 2006)	Non-hedge	**1**	**U.S. 195**	2	U.S. 255
Forward foreign exchange contracts					
(maturing 2006)	Hedge	**2**	**U.S. 29**		
(maturing 2006)	Non-hedge	**1**	**U.S. 208**	1	U.S. 129
Interest Rate					
Options	Non-hedge				U.S. 50
Interest rate swaps					
Canadian dollar					
(maturing 2007 to 2009)	Hedge	**1**	**100**	4	100
(maturing 2006 to 2011)	Non-hedge	**1**	**423**	5	485
		2		9	
U.S. dollar					
(maturing 2013)	Hedge		**U.S. 50**	3	U.S. 375
(maturing 2006 to 2010)	Non-hedge	**18**	**U.S. 550**	22	U.S. 500
		18		25	

Certain of the company's joint ventures use interest rate derivatives to manage interest rate exposures. The company's proportionate share of the fair value of the outstanding derivatives at December 31, 2005 was nil (2004 $1 million).

Energy Price Risk Management

The company executes power, natural gas and heat rate derivatives for overall management of its asset portfolio. Heat rate contracts are contracts for the sale or purchase of power that are priced based on a natural gas index. The fair value and notional volumes of contracts for differences and the swap, future, option and heat rate contracts are shown in the tables below.

Power

Asset/(Liability)

		2005	2004
December 31 (millions of dollars)	Accounting Treatment	**Fair Value**	Fair Value
Power swaps and contracts for differences			
(maturing 2006 to 2011)	Hedge	**(130)**	7
(maturing 2006 to 2010)	Non-hedge	**13**	(2)
Gas swaps, futures and options			
(maturing 2006 to 2016)	Hedge	**17**	(39)
(maturing 2006 to 2008)	Non-hedge	**(11)**	(2)
Heat rate contracts			
(maturing 2006)	Non-hedge		(1)

Notional Volumes

		Power (GWh)		**Gas (Bcf)**	
December 31, 2005	Accounting Treatment	**Purchases**	**Sales**	**Purchases**	**Sales**
Power swaps and contracts for differences					
(maturing 2006 to 2011)	Hedge	**2,566**	**7,780**		
(maturing 2006 to 2010)	Non-hedge	**1,332**	**456**		
Gas swaps, futures and options					
(maturing 2006 to 2016)	Hedge			**91**	**69**
(maturing 2006 to 2008)	Non-hedge			**15**	**18**
Heat rate contracts					
(maturing 2006)	Non-hedge		**35**		
December 31, 2004					
Power swaps and contracts for differences	Hedge	3,314	7,029		
	Non-hedge	438			
Gas swaps, futures and options	Hedge			80	84
	Non-hedge			5	8
Heat rate contracts	Non-hedge		229	2	

Certain of the company's joint ventures use power derivatives to manage energy price risk exposures. The company's proportionate share of the fair value of these outstanding power sales derivatives at December 31, 2005 was $(38) million (2004 nil) and relates to contracts which cover the period 2006 to 2008. The company's proportionate share of the notional sales volumes associated with this exposure at December 31, 2005 was 2,058 GWh (2004 nil).

RISK MANAGEMENT

Risk Management Overview

TransCanada and its subsidiaries are exposed to market, financial and counterparty risks in the normal course of their business activities. The risk management function assists in managing these various business activities and the risks associated with them. A strong commitment to a risk management culture by TransCanada's management supports this function. TransCanada's primary risk management objective is to protect earnings and cash flow and ultimately, shareholder value.

The risk management function is guided by the following principles that are applied to all businesses and risk types:

Board Oversight Risk strategies, policies and limits are subject to review and approval by TransCanada's Board of Directors.

Independent Review Risk-taking activities are subject to independent review, separate from the business lines that initiate the activity.

Assessment Processes are in place to ensure that risks are properly assessed at the transaction and counterparty levels.

Review and Reporting Market positions and exposures, and the creditworthiness of counterparties are subject to ongoing review and reporting to executive management.

Accountability Business lines are accountable for all risks and the related returns for their particular businesses.

Audit Review Risk processes are subject to internal audit review, with independent reporting to the Audit Committee of TransCanada's Board of Directors.

The processes within TransCanada'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 TransCanada's risk taking is consistent with the company's business objectives and risk tolerance. Risks are managed within limits ultimately established by the company's Board of Directors and implemented by senior management, monitored by risk management personnel and audited by internal audit personnel.

TransCanada manages market, financial and counterparty risks and related exposures in accordance with the company's market risk, interest rate and foreign exchange risk, and counterparty risk policies. The company's primary market and financial risks result from volatility in commodity positions and prices, interest rates and foreign currency exchange rates. Senior management reviews these exposures and reports on a regular basis to the Audit Committee of TransCanada's Board of Directors.

Market Risk Management

In order to manage market risk exposures created by fixed and variable pricing arrangements at different pricing indices and delivery points, the company enters into offsetting physical positions and derivative financial instruments. Market risks are quantified using value-at-risk methodology and are reviewed weekly by senior management.

Financial Risk Management

TransCanada monitors the financial market risk exposures relating to the company's investments in foreign currency denominated net assets, regulated and non-regulated long-term debt portfolios and foreign currency exposure on transactions. The market risk exposures created by these business activities are managed by establishing offsetting positions or through the use of derivative financial instruments.

Counterparty Risk Management

Counterparty risk is the financial loss that the company would experience if the counterparty failed to meet its obligations in accordance with the terms and conditions of its contracts with the company. Counterparty risk is mitigated by conducting financial and other assessments to establish

a counterparty's creditworthiness, setting exposure limits and monitoring exposures against these limits, and, where warranted, obtaining financial assurances.

The company's counterparty risk management practices and positions are further described in Note 16 to the consolidated financial statements.

Risks and Risk Management Related to the Kyoto Protocol

TransCanada is in the business of transporting natural gas and generating electricity to meet the growing energy needs of businesses and consumers throughout North America. While expanding the company's businesses, TransCanada continuously identifies and takes action to manage issues that could affect the company's ability to provide consumers with safe, reliable and cost-effective energy supplies. Among these issues are business risks associated with greenhouse gas emissions.

In Canada, TransCanada's fossil-fired power plants, pipeline assets and carbon black facilities are expected to be covered under legislation for large final emitters. While the broad elements of the proposed regulations to reduce greenhouse gas emissions intensities from large industrial emitters have been established, key policy elements remain outstanding, including details of compliance options that entities may use to fulfill compliance obligations. At this time, it is difficult to determine the level of impact to the company's Canadian assets until these and other key policy elements have been defined.

In 2006, TransCanada will continue with its strategy for managing the climate change issue. This strategy includes activities such as:

- energy conservation through improvements to overall system efficiency;
- conducting research and development work designed to reduce greenhouse gas emissions;
- gaining experience with flexible market mechanisms;
- participation in government-led policy forums; and
- taking part in public awareness initiatives and education programs focused on climate change and air quality issues.

In addition to these activities, TransCanada also ensures that the potential business risks and opportunities posed by increasing environmental priorities are considered when making decisions regarding the company's businesses.

Disclosure Controls and Procedures and Internal Controls

Pursuant to regulations adopted by the U.S. Securities and Exchange Commission (SEC), under the *Sarbanes-Oxley Act of 2002* and those of the Canadian Securities Administrators, TransCanada's management evaluates the effectiveness of the design and operation of the company's disclosure controls and procedures (disclosure controls). This evaluation is done under the supervision of, and with the participation of, the President and Chief Executive Officer and the Chief Financial Officer.

As of the end of the period covered by this Annual Report, TransCanada's management evaluated the effectiveness of its disclosure controls. Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer have concluded that TransCanada's disclosure controls are effective in ensuring that material information relating to TransCanada is made known to management on a timely basis, and is included in this Annual Report.

During the period covered by this Annual Report, there has been no change in internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, TransCanada's internal control over financial reporting.

CEO and CFO Certifications

With respect to the year ending December 31, 2005, TransCanada's President and Chief Executive Officer has provided the New York Stock Exchange with the annual CEO certification regarding TransCanada's compliance with the New York Stock Exchange's corporate governance listing standards applicable to foreign issuers. In addition, TransCanada's President and Chief Executive Officer and Chief Financial Officer have filed with the SEC certifications regarding the quality of TransCanada's public disclosures relating to its fiscal 2005 reports filed with the SEC.

Compliance Expenditures

The total cost incurred by TransCanada to meet compliance requirements of Sections 302, 404 and 906 of the *Sarbanes-Oxley Act of 2002* for the period January 1, 2002 to December 31, 2005, was estimated to be $9 million, including third party charges of $3 million.

CRITICAL ACCOUNTING POLICY

The company accounts for the impacts of rate regulation in accordance with generally accepted accounting principles (GAAP) as outlined in Notes 1 and 12 to the consolidated financial statements. Three criteria must be met to use these accounting principles: the rates for regulated services or activities must be subject to approval by a regulator; the regulated rates must be designed to recover the cost of providing the services or products; and it must be reasonable to assume that rates set at levels to recover the cost can be charged to and will be collected from customers in view of the demand for services or products and the level of direct and indirect competition. The company's management believes that all three of these criteria have been met. The most significant impact from the use of these accounting principles is that in order to appropriately reflect the economic impact of the regulators' decisions regarding the company's revenues and tolls, and to thereby achieve a proper matching of revenues and expenses, the timing of recognition of certain expenses and revenues in the regulated businesses may differ from that otherwise expected under GAAP as detailed in Note 12 to the consolidated financial statements.

As prescribed by the regulators, the taxes payable method of accounting for income taxes is used for tollmaking purposes for Canadian regulated natural gas transmission operations. As permitted by GAAP, this method is also used for accounting purposes, since there is reasonable expectation that future income taxes payable will be included in future costs of service and recorded in revenues at that time. Consequently, future income tax liabilities have not been recognized as it is expected that when these amounts become payable, they will be recovered through future rate revenues. In the absence of rate regulation accounting, GAAP would require the recognition of future income tax liabilities. If the liability method of accounting had been used, additional future income tax liabilities in the amount of $1,619 million at December 31, 2005 would have been recorded.

CRITICAL ACCOUNTING ESTIMATE

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 is depreciation expense. TransCanada's plant, property and equipment are depreciated on a straight-line basis over their estimated useful lives. Depreciation expense for the year ended December 31, 2005 was $1,017 million. Depreciation expense impacts the Gas Transmission and Power segments of the company. In the Gas Transmission business, depreciation rates are approved by the regulators, where applicable, and depreciation expense is recoverable based on the cost of providing the services or products. A change in the estimation of the useful lives of the plant, property and equipment in the Gas Transmission segment would, if recovery through rates is permitted by the regulators, have no material impact on TransCanada's net income but would directly impact funds generated from operations.

ACCOUNTING CHANGES

Financial Instruments Disclosure and Presentation

Effective January 1, 2005, the Company adopted the amendment of the Canadian Institute of Chartered Accountants (CICA) 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 the issuance of the issuer's equity shares as debt when the instrument that embodies the obligations does not establish an ownership relationship. In accordance with this amendment, TransCanada classified the non-controlling interest component of preferred

securities as long-term debt. This change was applied retroactively with restatement of prior periods. See Note 2 to the consolidated financial statements for the impact of this accounting change.

Disclosure by Entities Subject to Rate Regulation

In May 2005, the Accounting Standards Board (AcSB) issued Accounting Guideline AcG-19 "Disclosures by Entities Subject to Rate Regulation" to improve the quality and consistency of disclosures by entities subject to rate regulation. Under AcG-19, all rate regulated entities are required to disclose general information about the rate-setting process, its accounting effects and the operations affected. The new disclosure requirements were effective for fiscal years ending on or after December 31, 2005. The company adopted these requirements effective December 31, 2005. See Note 12 to the consolidated financial statements for disclosures required under AcG-19.

Limited Partnerships

A wholly-owned subsidiary of TransCanada serves as the general partner of PipeLines LP. Effective December 31, 2005, TransCanada consolidated limited partnerships when the general partner controls the strategic operating, financing and investing activities of the limited partnerships and the limited partners do not have substantive participating rights. This change was applied retroactively with restatement of prior periods. There was no impact on previously recorded net income and the balance sheet and income statement impact was not material.

Consolidation of Variable Interest Entities

In June 2003, the Accounting Standards Board of the CICA issued a new Accounting Guideline "Consolidation of Variable Interest Entities" which requires enterprises to identify variable interest entities in which they have an interest, determine whether they are the primary beneficiary of such entities and, if so, to consolidate them. For TransCanada, the guideline's requirements were effective as of January 1, 2005. Adopting the provisions of this guideline had no impact on the company's consolidated financial statements.

Non-Monetary Transactions

In June 2005, the AcSB issued the new Handbook Section 3831 "Non-Monetary Transactions" replacing Section 3830 of the same title. The revised standard requires all non-monetary transactions to be measured at fair value, subject to certain exceptions. Commercial substance replaces culmination of the earnings process as the test for fair value measurement and is a function of the cash flows expected from the exchanged assets. The new requirements are effective for non-monetary transactions initiated in periods beginning on or after January 1, 2006. Adopting the provisions of this standard is not expected to have an impact on the company's consolidated financial statements.

Financial Instruments Recognition and Measurement

In January 2005, the AcSB issued the new Handbook Section 3855 "Financial Instruments Recognition and Measurement" which prescribes that all financial instruments within the scope of this standard, including derivatives, be included on a company's balance sheet and measured, either at their fair value or, in limited circumstances when fair value may not be considered most relevant, at cost or amortized cost. It also specifies when gains and losses as a result of changes in fair value are to be recognized in the income statement. This standard is effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2006. This standard is substantially similar to the corresponding requirements under Statement of Financial Accounting Standards (SFAS) No. 115 "Accounting for Certain Investments in Debt and Equity Securities" and SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities" which were adopted by the company for U.S. GAAP purposes, effective January 1, 2001. This new Handbook section will be adopted by the company as of January 1, 2007 on a prospective basis. TransCanada does not expect the new Canadian requirement to have a significant impact on the company's consolidated financial statements. See the company's reconciliation to United States GAAP posted on www.sec.gov/edgar.shtml for the impact of SFAS No. 133 on the company's consolidated financial statements.

Hedges

In January 2005, the AcSB issued the new Handbook Section 3865 "Hedges" which specifies the circumstances under which hedge accounting is permissible, how hedge accounting may be performed, and where the impacts should be recorded. The provisions of this standard introduce three specific types of hedging relationships: fair value hedges, cash

flow hedges and hedges of a net investment in self-sustaining foreign operations. This standard is effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2006. The standard builds on existing Accounting Guideline AcG-13 "Hedging Relationships" which was adopted by TransCanada effective January 1, 2004. This new Handbook section will be adopted by the company as of January 1, 2007 on a prospective basis. TransCanada does not expect the new requirement to have a significant impact on the company's consolidated financial statements.

Comprehensive Income

In January 2005, the AcSB issued the new Handbook Section 1530 "Comprehensive Income" which requires that an enterprise present comprehensive income and its components, in a separate financial statement that is displayed with the same prominence as other financial statements. This Section introduces a new requirement to present certain gains and losses temporarily outside net income. This standard is effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2006. This standard is substantially similar to the corresponding requirements under SFAS No. 130 "Reporting Comprehensive Income" and SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities" which have already been adopted by the company for U.S. GAAP purposes. This Handbook section will be adopted by the company as of January 1, 2007 on a prospective basis. TransCanada does not expect the new Canadian requirement to have a significant impact on the company's consolidated financial statements. See the company's reconciliation to United States GAAP posted on www.sec.gov/edgar.shtml for the impact of SFAS No. 130 and SFAS No. 133 on the company's consolidated financial statements.

DISCONTINUED OPERATIONS

TransCanada's Board of Directors approved plans in previous years to dispose of the company's International, Canadian Midstream, Gas Marketing and certain other businesses. As of December 31, 2003, TransCanada's investments in Gasoducto del Pacifico (Gas Pacifico), INNERGY Holdings S.A. (INNERGY) and Paiton Energy, which were previously approved for disposal, were accounted for as part of continuing operations due to the length of time it had taken the company to dispose of these assets. Gas Pacifico and INNERGY are included in the Gas Transmission segment. It is the intention of the company to continue with its plan to dispose of these investments. Paiton Energy was sold in November 2005 and the gain on sale was recorded in the Power segment.

In 2005, the company reviewed the provision for loss on discontinued operations and concluded that the provision was adequate.

In 2004 and 2003, the company recognized in income $52 million and $50 million, respectively, related to the original $102 million after-tax deferred gain on the sale of Gas Marketing.

SUBSIDIARIES AND INVESTMENTS

TransCanada's subsidiaries and investments that hold significant operating assets are noted below.

Subsidiary Investment	Major Operating Assets	Organized Under the Laws of	Effective Percentage Ownership by TransCanada[1]
TransCanada PipeLines Limited	Canadian Mainline and BC System	Canada	100
NOVA Gas Transmission Ltd.	Alberta System	Alberta	100
TransCanada Pipeline Ventures Ltd.	Ventures LP	Alberta	100
Foothills Pipe Lines Ltd.	Foothills System	Canada	100
TransCanada PipeLine USA Ltd.		Nevada	100
TransCanada Hydro Northeast Inc.	TC Hydro	Delaware	100
Gas Transmission Northwest Corporation	GTN	California	100
TransCanada Power Marketing Ltd.	U.S. Power assets	Delaware	100
Great Lakes Gas Transmission Limited Partnership	Great Lakes	Delaware	50
Iroquois Gas Transmission System L.P.	Iroquois	Delaware	44.5
Portland Natural Gas Transmission System Partnership	Portland	Maine	61.7
TC PipeLines, LP	TC PipeLines, LP assets	Delaware	13.4
Northern Border Pipeline Company	Northern Border	Texas	4
Tuscarora Gas Transmission Company	Tuscarora	Nevada	7.6
TransCanada Energy Ltd.	Canadian Power assets	Canada	100
Bruce Power A L.P.	Bruce A Units 1 to 4	Ontario	47.9
Bruce Power L.P.	Bruce B Units 5 to 8	Ontario	31.6
Trans Québec & Maritimes Pipeline Inc.	TQM	Canada	50
CrossAlta Gas Storage & Services Ltd.	CrossAlta	Alberta	60
TransGas de Occidente S.A.	TransGas	Colombia	46.5

(1) Percentage ownership represents the effective common share ownership as at December 31, 2005.

SELECTED THREE YEAR CONSOLIDATED FINANCIAL DATA[1]

(millions of dollars except per share amounts)

	2005	2004	2003
Income Statement			
Revenues	**6,124**	5,497	5,636
Net income			
Continuing operations	**1,209**	980	801
Discontinued operations		52	50
Total	**1,209**	1,032	851
Balance Sheet			
Total assets	**24,113**	22,422	20,887
Long-term debt	**9,640**	9,749	9,516
Non-recourse debt of joint ventures	**937**	808	741
Preferred securities	**536**	554	598
Per Common Share Data			
Net income Basic			
Continuing operations	**$2.49**	$2.02	$1.66
Discontinued operations		0.11	0.10
	$2.49	$2.13	$1.76
Net income Diluted			
Continuing operations	**$2.47**	$2.01	$1.66
Discontinued operations		0.11	0.10
	$2.47	$2.12	$1.76
Dividends declared	**$1.22**	$1.16	$1.08

(1) The selected three year consolidated financial data has been prepared in accordance with Canadian GAAP. Certain comparative figures have been reclassified to conform with the current year's presentation. For a discussion on the factors affecting the comparability of the financial data, including discontinued operations, refer to Note 1, Note 2 and Note 23 of TransCanada's 2005 audited consolidated financial statements.

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA[1]

	2005			
(millions of dollars except per share amounts)	**Fourth**	**Third**	**Second**	**First**
Revenues	**1,771**	**1,494**	**1,449**	**1,410**
Net Income				
Continuing operations	**350**	**427**	**200**	**232**
Discontinued operations				
	350	**427**	**200**	**232**
Share Statistics				
Net income per share Basic				
Continuing operations	**$0.72**	**$0.88**	**$0.41**	**$0.48**
Discontinued operations				
	$0.72	**$0.88**	**$0.41**	**$0.48**
Net income per share Diluted				
Continuing operations	**$0.71**	**$0.87**	**$0.41**	**$0.48**
Discontinued operations				
	$0.71	**$0.87**	**$0.41**	**$0.48**
Dividend declared per common share	**$0.305**	**$0.305**	**$0.305**	**$0.305**

	2004			
	Fourth	Third	Second	First
Revenues	1,480	1,311	1,347	1,359
Net Income				
Continuing operations	185	193	388	214
Discontinued operations		52		
	185	245	388	214
Share Statistics				
Net income per share Basic				
Continuing operations	$0.38	$0.40	$0.80	$0.44
Discontinued operations		0.11		
	$0.38	$0.51	$0.80	$0.44

Net income per share Diluted				
Continuing operations	$0.38	$0.39	$0.80	$0.44
Discontinued operations		0.11		
	$0.38	$0.50	$0.80	$0.44
Dividend declared per common share	$0.29	$0.29	$0.29	$0.29

(1) The selected quarterly consolidated financial data has been prepared in accordance with Canadian GAAP. Certain comparative figures have been reclassified to conform with the current year's presentation. For a discussion on the factors affecting the comparability of the financial data, including discontinued operations, refer to Note 1, Note 2 and Note 23 of TransCanada's 2005 audited consolidated financial statements.

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 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 builds, owns and operates electrical power generation plants and sells electricity, 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 2005 and 2004 quarterly net earnings are as follows.

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 Generic Cost of Capital 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 and recorded $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.

Second quarter 2005 net earnings included $21 million ($13 million related to 2004 and $8 million related to the six months ended June 30, 2005) with respect to the NEB's decision on the Canadian Mainline's 2004 Tolls and Tariff Application (Phase II). On April 1, 2005, TransCanada completed the acquisition of the TC Hydro hydroelectric generation assets from USGen. Bruce Power's equity income was lower than previous quarters due to the continuing impact of planned maintenance outages and an unplanned maintenance outage on Unit 6 relating to a transformer fire.

In third quarter 2005, net earnings included a $193 million after-tax gain related to the sale of the company's ownership interest in Power LP. In addition, Bruce Power's equity income increased from prior quarters due to higher realized power prices and slightly higher generation volumes.

In fourth quarter 2005, net earnings included a $115 million after-tax gain on sale of Paiton Energy. In addition, Bruce A was formed and Bruce Power's results were proportionately consolidated, effective October 31.

FOURTH QUARTER 2005 HIGHLIGHTS

SEGMENT RESULTS-AT-A-GLANCE

Three months ended December 31 (millions of dollars except per share amounts)

	2005	2004
Gas Transmission	**160**	157
Power		
Excluding gains	**82**	31
Gain on sale of Paiton Energy	**115**	
	197	31
Corporate	**(7)**	(3)
Net Income[1]	**350**	185
Net Income Per Share Basic[2]	**$0.72**	$0.38
[1] **Net Income**		
Excluding gain	**235**	185
Gain on sale of Paiton Energy	**115**	
	350	185
[2] **Net Income Per Share Basic**		
Excluding gain	**$0.48**	$0.38
Gain on sale of Paiton Energy	**0.24**	
	$0.72	$0.38

Net income for fourth quarter 2005 of $350 million or $0.72 per share increased by $165 million or $0.34 per share compared to $185 million or $0.38 per share for fourth quarter 2004. This increase was due to significantly higher net income from the Power business, including an after-tax gain of $115 million or $0.24 per share from the sale of Paiton Energy.

Excluding the $115 million gain related to the sale of Paiton Energy, net income for fourth quarter 2005 increased $50 million or $0.10 per share compared to fourth quarter 2004, to $235 million or $0.48 per share. This was due to increases of $51 million and $3 million in net income from the Power and Gas Transmission businesses, respectively, partially offset by an increase of $4 million in net expenses in Corporate.

The increase in Power's net income was primarily due to higher operating and other income from Bruce Power and Eastern Operations. Bruce Power's contribution to operating and other income increased by $48 million in fourth quarter 2005 compared to fourth quarter 2004, primarily due to higher realized power prices on uncontracted volumes sold into Ontario's wholesale spot market, higher generation volumes and an increased ownership interest in the Bruce A facilities effective October 31, 2005.

Western Operations' operating and other income was $8 million higher in fourth quarter 2005 compared to fourth quarter 2004 primarily due to increased margins in fourth quarter 2005 as a result of higher market heat rates on uncontracted volumes of power sold. Partially offsetting this increase were lower contributions from the Bear Creek cogeneration facility which remained on an unplanned outage throughout the quarter.

Eastern Operations' operating and other income was $37 million higher in fourth quarter 2005 compared to fourth quarter 2004 primarily due to contributions from TC Hydro, acquired on April 1, 2005, and from the Grandview

cogeneration facility placed into service in January 2005. Partially offsetting these increases was a fourth quarter 2004 positive impact due to a restructuring transaction relating to OSP power purchase contracts and the loss of operating income associated with the expiration of certain long-term sales contracts in 2004.

General, administrative, support costs and other increased $9 million in fourth quarter 2005 compared to fourth quarter 2004 primarily due to higher business development costs expensed in 2005 and the positive impact in fourth quarter 2004 of the recognition of unrealized foreign exchange gains on Power LP's U.S. dollar denominated debt.

For fourth quarter 2005, Gas Transmission's net income was $160 million compared to $157 million in fourth quarter 2004. The $3 million increase was due to a $6 million increase in net income from the Other Gas Transmission businesses partially offset by a $3 million reduction in income from Wholly-Owned Pipelines. The reduction in income from Wholly-Owned Pipelines was primarily due to a decline in the Canadian Mainline and the Alberta System net income. These decreases were partially offset by higher net income during the quarter from TransCanada's investment in GTN which was acquired on November 1, 2004. The increase in net income from Other Gas Transmission was primarily due to lower project development costs expensed in fourth quarter 2005 resulting from capitalization of costs of the Broadwater and Keystone projects in 2005 and higher income from Gas Pacifico. These increases were partially offset by lower income from Great Lakes and Ventures LP.

Net expenses, after tax, in Corporate for fourth quarter 2005 were $7 million compared to $3 million for the corresponding period in 2004. The $4 million increase in net expenses was primarily due to increased net interest costs offset by an income tax refund received in fourth quarter 2005 relating to prior years.

SHARE INFORMATION

As at February 27, 2006, TransCanada had 487,489,628 issued and outstanding common shares. In addition, there were 9,661,488 outstanding options to purchase common shares, of which 7,303,084 were exercisable as at February 27, 2006.

OTHER INFORMATION

Additional information relating to TransCanada, including the company's Annual Information Form and continuous disclosure documents, is posted on SEDAR at www.sedar.com under TransCanada Corporation.

Other selected consolidated financial information for the years ended December 31, 2005, 2004, 2003, 2002, 2001 and 2000 is found under the heading "Six-Year Financial Highlights" on pages 115 and 116 of this Annual Report.

GLOSSARY OF TERMS

AcSB	Accounting Standards Board
APG	Aboriginal Pipeline Group/Mackenzie Valley Aboriginal Pipeline Limited Partnership
Bcf	Billion cubic feet
B.C.	British Columbia
Bcf/d	Billion cubic feet per day
Boston Edison	Boston Edison Company
BPC	BPC Generation Infrastructure Trust
Broadwater	Broadwater Energy project
Bruce A	Bruce Power A L.P.
Bruce B	Bruce Power L.P.
Bruce Power	Bruce A and Bruce B, collectively
Calpine	Calpine Corporation and certain of its subsidiaries
Cameco	Cameco Corporation
CAPP	Canadian Association of Petroleum Producers
Cartier Wind	Cartier Wind Energy
CBM	Coalbed methane
CFE	Comisión Federal de Electricdad
CICA	Canadian Institute of Chartered Accountants
CPPL	ConocoPhillips Pipe Line Company
CrossAlta	CrossAlta Gas Storage & Services Ltd.
DBRS	Dominion Bond Rating Service Limited
Debentures	Senior Unsecured Debentures
disclosure controls	Disclosure controls and procedures
EPCOR	EPCOR Utilities Inc.
EUB	Alberta Energy and Utilities Board
FERC	Federal Energy Regulatory Commission
Foothills	Foothills Pipe Lines Ltd.
FT	Firm transportation
GAAP	Generally accepted accounting principles
Gas Pacifico	Gasoducto del Pacifico
GCOC	Generic cost of capital
GJ	Gigajoules
GRA	General Rate Application
Great Lakes	Great Lakes Gas Transmission System
GTN	Gas Transmission Northwest System and the North Baja System, collectively
GTNC	Gas Transmission Northwest Corporation
GUA	Gas Utilities Act (Alberta)
GWh	Gigawatt hours
Hydro-Québec	Hydro-Québec Distribution
IID	Imperial Irrigation District
INNERGY	INNERGY Holdings S.A.
Iroquois	Iroquois Gas Transmission System
Irving	Irving Oil
Keystone pipeline	Keystone oil pipeline
km	Kilometres
LNG	Liquefied natural gas
Millennium	Millennium Pipeline Project
mmcf/d	Million cubic feet per day
Moody's	Moody's Investors Service
MOU	Memorandum of Understanding
MW	Megawatt
MWh	Megawatt hour
NEB	National Energy Board
Net earnings	Net income from continuing operations
Northern Border	Northern Border Pipeline Company
NPA	Northern Pipeline Act
OM&A	Operating, maintenance and administration
OPA	Ontario Power Authority
OSP	Ocean State Power
PG&E	Pacific Gas & Electric Company
Paiton Energy	P.T. Paiton Energy Company
PipeLines LP	TC PipeLines, LP
PJ	Petajoules
Portland	Portland Natural Gas Transmission System
Portlands Energy	Portlands Energy Centre L.P.
Power LP	TransCanada Power, L.P.
PPA	Power purchase arrangement

ROE	Rate of return on common equity
SFAS	Statement of Financial Accounting Standards
Shell	Shell US Gas & Power LLC
STFT	Short-term firm transportation service
TC Hydro	Hydroelectric generation assets acquired from USGen
Tcf	Trillion cubic feet
TCPL	TransCanada PipeLines Limited
TCPM	TransCanada Power Marketing Limited
TQM	Trans Québec & Maritimes System
TransCanada or the company	TransCanada Corporation
TransGas	TransGas de Occidente S.A.
Tuscarora	Tuscarora Gas Transmission System
U.S.	United States
USGen	USGen New England
Ventures LP	TransCanada Pipeline Ventures Limited Partnership
WCSB	Western Canada Sedimentary Basin

Report of Management

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

Management has prepared Management's Discussion and Analysis which is based on the Company's financial results prepared in accordance with Canadian GAAP. It compares the Company's financial performance in 2005 to 2004 and should be read in conjunction with the consolidated financial statements and accompanying notes. In addition, significant changes between 2004 and 2003 are highlighted.

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

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

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

The independent external auditors, KPMG LLP, have been appointed by the shareholders to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's financial position, results of operations and cash flows in accordance with Canadian GAAP. The report of KPMG LLP on page 75 outlines the scope of their examination and their opinion on the consolidated financial statements.

Harold N. Kvisle
President and
Chief Executive Officer

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

Auditors' Report

To the Shareholders of TransCanada Corporation

We have audited the consolidated balance sheets of TransCanada Corporation as at December 31, 2005 and 2004 and the consolidated statements of income, retained earnings and cash flows for each of the years in the three-year period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and 2004 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2005 in accordance with Canadian generally accepted accounting principles.

Chartered Accountants
Calgary, Canada

February 27, 2006

TRANSCANADA CORPORATION

CONSOLIDATED INCOME

Year ended December 31 *(millions of dollars except per share amounts)*	**2005**	2004	2003
Revenues	**6,124**	5,497	5,636
Operating Expenses			
Cost of sales	**1,168**	940	979
Other costs and expenses	**1,889**	1,615	1,666
Depreciation	**1,017**	948	917
	4,074	3,503	3,562
Operating Income	**2,050**	1,994	2,074
Other Expenses/(Income)			
Financial charges (Note 9)	**836**	858	878
Financial charges of joint ventures (Note 10)	**66**	63	80
Equity income (Note 7)	**(247)**	(213)	(206)
Interest income and other	**(63)**	(59)	(60)
Gains on sale of assets (Note 8)	**(445)**	(204)	
	147	445	692
Income from Continuing Operations before Income Taxes and Non-Controlling Interests	**1,903**	1,549	1,382
Income Taxes (Note 17)			
Current	**550**	414	284
Future	**60**	77	230
	610	491	514
Non-Controlling Interests (Note 14)	**84**	78	67
Net Income from Continuing Operations	**1,209**	980	801
Net Income from Discontinued Operations (Note 23)		52	50
Net Income	**1,209**	1,032	851
Net Income Per Share (Note 15)			
Basic			
Continuing operations	**$2.49**	$2.02	$1.66
Discontinued operations		0.11	0.10
	$2.49	$2.13	$1.76
Diluted			

Continuing operations	**$2.47**	$2.01	$1.66
Discontinued operations		0.11	0.10
	$2.47	$2.12	$1.76

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

TRANSCANADA CORPORATION

CONSOLIDATED CASH FLOWS

Year ended December 31 *(millions of dollars)*	**2005**	2004	2003
Cash Generated from Operations			
Net income from continuing operations	**1,209**	980	801
Depreciation	**1,017**	948	917
Gains on sale of assets, net of current tax (Note 8)	**(318)**	(204)	
Equity income in excess of distributions received (Note 7)	**(71)**	(113)	(117)
Future income taxes	**60**	77	230
Non-controlling interests	**84**	78	67
Funding of employee future benefits in excess of expense	**(9)**	(29)	(65)
Other	**(21)**	(34)	(11)
Funds generated from operations	**1,951**	1,703	1,822
(Increase)/decrease in operating working capital (Note 21)	**(49)**	29	93
Net cash provided by operations	**1,902**	1,732	1,915
Investing Activities			
Capital expenditures	**(754)**	(530)	(395)
Acquisitions, net of cash acquired (Note 8)	**(1,317)**	(1,516)	(570)
Disposition of assets, net of current tax (Note 8)	**671**	410	
Deferred amounts and other	**64**	(12)	(131)
Net cash used in investing activities	**(1,336)**	(1,648)	(1,096)
Financing Activities			
Dividends on common shares	**(586)**	(552)	(510)
Distributions paid to non-controlling interests	**(74)**	(87)	(79)
Notes payable issued/(repaid), net	**416**	179	(62)
Long-term debt issued	**799**	1,090	930
Reduction of long-term debt	**(1,113)**	(1,005)	(753)
Long-term debt of joint ventures issued	**38**	217	60
Reduction of long-term debt of joint ventures	**(80)**	(112)	(72)
Common shares issued (Note 15)	**44**	32	65
Partnership units of joint ventures issued		88	
Redemption of junior subordinated debentures			(218)
Net cash used in financing activities	**(556)**	(150)	(639)
Effect of Foreign Exchange Rate Changes on Cash and Short-Term Investments	**11**	(87)	(54)
Increase/(Decrease) in Cash and Short-Term Investments	**21**	(153)	126
Cash and Short-Term Investments			
Beginning of year	**191**	344	218
Cash and Short-Term Investments			
End of year	**212**	191	344

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

TRANSCANADA CORPORATION

CONSOLIDATED BALANCE SHEET

December 31 *(millions of dollars)*	**2005**	2004
ASSETS		
Current Assets		
Cash and short-term investments	**212**	191
Accounts receivable	**796**	616
Inventories	**281**	174
Other	**277**	120
	1,566	1,101
Long-Term Investments (Note 7)	**400**	1,098
Plant, Property and Equipment (Notes 4, 9 and 10)	**20,038**	18,764
Other Assets (Note 5)	**2,109**	1,459
	24,113	22,422
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable (Note 18)	**962**	546
Accounts payable	**1,494**	1,135
Accrued interest	**222**	214
Current portion of long-term debt (Note 9)	**393**	774
Current portion of long-term debt of joint ventures (Note 10)	**41**	85
	3,112	2,754
Deferred Amounts (Note 11)	**1,196**	783
Future Income Taxes (Note 17)	**703**	509
Long-Term Debt (Note 9)	**9,640**	9,749
Long-Term Debt of Joint Ventures (Note 10)	**937**	808
Preferred Securities (Note 13)	**536**	554
	16,124	15,157
Non-Controlling Interests (Note 14)	**783**	700
Shareholders' Equity		
Common shares (Note 15)	**4,755**	4,711
Contributed surplus	**272**	270
Retained earnings	**2,269**	1,655
Foreign exchange adjustment (Note 16)	**(90)**	(71)
	7,206	6,565
Commitments, Contingencies and Guarantees (Note 22)		
	24,113	22,422

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

On behalf of the Board:

Harold N. Kvisle
Director

Harry G. Schaefer
Director

TRANSCANADA CORPORATION

CONSOLIDATED RETAINED EARNINGS

Year ended December 31 *(millions of dollars)*	**2005**	2004	2003
Balance at beginning of year	**1,655**	1,185	854
Net income	**1,209**	1,032	851
Common share dividends	**(595)**	(562)	(520)
	2,269	1,655	1,185

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

TRANSCANADA CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

Gas Transmission

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

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

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

Power

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

TransCanada owns and operates:

- hydroelectric generation assets located in New Hampshire, Vermont and Massachusetts (TC Hydro);
- a natural gas-fired, combined-cycle Ocean State Power (OSP) plant in Burrillville, Rhode Island;
- natural gas-fired cogeneration plants in Alberta at Carseland, Redwater, Bear Creek and MacKay River;
- the Grandview natural gas-fired cogeneration plant near Saint John, New Brunswick; and
- a waste-heat fuelled cogeneration power plant at the Cancarb facility in Medicine Hat, Alberta.

TransCanada owns but does not operate:

a 47.9 per cent partnership interest and a 31.6 per cent partnership interest in the nuclear power generation facilities of Bruce Power A L.P. (Bruce A) and Bruce Power L.P. (Bruce B), respectively (collectively Bruce Power), located near Lake Huron, Ontario.

TransCanada has long-term power purchase arrangements (PPAs) in place for:

100 per cent of the production of the Sundance A and 50 per cent, through a partnership, of the production of the Sundance B power facilities near Wabamun, Alberta; and

100 per cent of the production of the Sheerness power facility near Hanna, Alberta.

TransCanada has under construction:

the Bécancour natural gas-fired cogeneration plant near Trois-Rivières, Québec; and

six Cartier Wind Energy projects in Québec, owned 62 per cent by TransCanada.

NOTE 1 ACCOUNTING POLICIES

The consolidated financial statements of the Company have been prepared by Management in accordance with Canadian generally accepted accounting principles (GAAP). Amounts are stated in Canadian dollars unless otherwise indicated. Certain comparative figures have been reclassified to conform with the current year's presentation.

Since a determination of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of these consolidated financial statements requires the use of estimates and assumptions which have been made using careful judgment. In the opinion

of Management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized below.

Basis of Presentation

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

Regulation

The Canadian Mainline, the BC System, the Foothills System and Trans Québec & Maritimes Pipeline Inc. (Trans Québec & Maritimes) are subject to the authority of the National Energy Board (NEB) and the Alberta System is regulated by the Alberta Energy and Utilities Board (EUB). The Gas Transmission Northwest System, the North Baja System and the other natural gas pipelines in the U.S. are subject to the authority of the Federal Energy Regulatory Commission (FERC). These natural gas transmission operations are regulated with respect to the determination of revenues, tolls, construction and operations. In order to appropriately reflect the economic impact of the regulators' decisions regarding the Company's revenues and tolls, and to thereby achieve a proper matching of revenues and expenses, the timing of recognition of certain revenues and expenses in these regulated businesses may differ from that otherwise expected under GAAP. The impact of rate regulation on TransCanada is provided in Note 12.

Revenue Recognition

Gas Transmission

In the Gas Transmission business, revenues from the Canadian rate-regulated operations are recognized in accordance with the decisions made by the NEB and EUB. Revenues from the U.S. rate-regulated operations are recorded in accordance with FERC rules and regulations. Revenues from non-regulated operations are recorded when products have been delivered or services have been performed.

Power

The majority of revenues from the Power business are derived from the sale of electricity from energy marketing and trading activities and are recorded in the month of delivery. Revenues from the Power business are also derived from the sale of unutilized natural gas fuel and energy derivative contracts, including financial swaps, futures contracts and options.

Dilution Gains

Dilution gains which result from the sale of units by limited partnerships in which TransCanada has an ownership interest are recognized immediately in net income.

Cash and Short-Term Investments

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

Inventories

Inventories consisting of natural gas in storage, uranium, materials and supplies, including spare parts, are carried at the lower of average cost or net realizable value.

Plant, Property and Equipment

Gas Transmission

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

Power

Major power generation plant, equipment and structures in the Power business are recorded at cost and depreciated on a straight-line basis over estimated service lives at average annual rates ranging from two to ten per cent. Nuclear assets under capital lease are initially recorded at the present value of minimum lease payments at the inception of the lease and amortized on a straight-line basis over the shorter of their

useful life or remaining lease term. Other equipment is depreciated at various rates. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives. Interest is capitalized on projects under construction.

Corporate

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

Power Purchase Arrangements

PPAs are long-term contracts to purchase or sell power on a predetermined basis. The initial payments for PPAs acquired by TransCanada are deferred and amortized over the terms of the contracts, from the dates of acquisition, which range from ten to 19 years. Certain PPAs under which TransCanada sells power are accounted for as operating leases and, accordingly, the related plant, property and equipment are accounted for as assets under operating leases.

Stock Options

TransCanada's Stock Option Plan permits the award of options to purchase the Company's common shares to certain employees, some of whom are officers. The contractual life of options granted subsequent to 2002 is seven years and for options granted prior to 2003, the contractual life is ten years. Options may be exercised at a price determined at the time the option is awarded and vest 33.3 per cent on each of the three following award date anniversaries. The Company records compensation expense over the three year vesting period. This charge is reflected in the Gas Transmission and Power segments.

Income Taxes

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

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

Foreign Currency Translation

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

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

Derivative Financial Instruments and Hedging Activities

The Company utilizes derivative and other financial instruments to manage its exposure to changes in foreign currency exchange rates, interest rates and energy commodity prices.

Derivatives and other instruments must be designated and effective to qualify for hedge accounting. Derivatives are recorded at their fair value at each balance sheet date. For cash flow and fair value hedges, gains or losses relating to derivatives are deferred and recognized in the same period and in the same financial statement category as the corresponding hedged transactions. For hedges of net investments in self-sustaining foreign operations, exchange gains or losses on derivatives, net of tax, and designated foreign currency denominated debt are offset against the exchange losses or gains arising on the translation of the financial statements of the foreign operations included in the foreign exchange adjustment account in Shareholders' Equity. In the event that a derivative does not meet the designation or effectiveness criteria, realized and unrealized gains or losses are recognized in income each period in the same financial statement category as the underlying transaction giving rise to the exposure being economically hedged. Premiums paid or received with respect to derivatives that are hedges are deferred and amortized to income over the term of the hedge.

If a derivative that previously qualified as a hedge is settled, de-designated or ceases to be effective, the gain or loss at that date is deferred and recognized in the same period and in the same financial statement category as the corresponding hedged transactions. If a hedged anticipated transaction is no longer probable to occur, related deferred gains or losses are recognized in income in the current period.

The recognition of gains and losses on derivatives for Canadian Mainline, Alberta System, the BC System and the Foothills System exposures is determined through the regulatory process.

Asset Retirement Obligation

The Company recognizes the fair value of a liability for an asset retirement obligation, where a legal obligation exists, in the period in which it is incurred if a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset and the liability is accreted at the end of each period through charges to operating expenses.

Employee Benefit and Other Plans

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

The Company has broad-based, medium-term employee incentive plans, which grant units to each eligible employee and are payable in cash at the date of vesting. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, units vest when certain conditions are met, including the employee's continued employment during a specified period and achievement of specified corporate performance targets.

Certain of the Company's joint ventures sponsor DB Plans and other post-employment benefit plans. The Company records its proportionate share of expenses, funding contributions and accrued benefit assets and liabilities related to these plans.

NOTE 2 ACCOUNTING CHANGES

Financial Instruments Disclosure and Presentation

Effective January 1, 2005, the Company adopted the amendment of the Canadian Institute of Chartered Accountants (CICA) 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 prior years was nil.

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

(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.

Limited Partnerships

A wholly-owned subsidiary of TransCanada serves as the general partner of TC PipeLines, LP (PipeLines LP). Effective December 31, 2005, TransCanada consolidated limited partnerships when the general partner controls the strategic operating, financing and investing activities of the limited partnerships and the limited partners do not have substantive participating rights. This change was applied retroactively. There was no impact on previously recorded net income and the balance sheet and income statement impact was not material.

NOTE 3 SEGMENTED INFORMATION

NET INCOME/(LOSS)[1]

Year ended December 31, 2005 (millions of dollars)	Gas Transmission	Power	Corporate	Total
Revenues	4,163	1,961		6,124
Cost of sales[2]		(1,168)		(1,168)
Other costs and expenses	(1,380)	(505)	(4)	(1,889)
Depreciation	(938)	(79)		(1,017)
Operating income/(loss)	1,845	209	(4)	2,050
Financial charges and non-controlling interests	(788)	(2)	(130)	(920)
Financial charges of joint ventures	(57)	(9)		(66)
Equity income	79	168		247
Interest income and other	25	5	33	63
Gains on sale of assets	82	363		445
Income taxes	(502)	(173)	65	(610)
Net income from continuing operations	684	561	(36)	1,209
Net income from discontinued operations				
Net Income				1,209

Year ended December 31, 2004 (millions of dollars)				
Revenues	3,929	1,568		5,497
Cost of sales[2]		(940)		(940)
Other costs and expenses	(1,228)	(384)	(3)	(1,615)
Depreciation	(876)	(72)		(948)
Operating income/(loss)	1,825	172	(3)	1,994
Financial charges and non-controlling interests	(848)	(9)	(79)	(936)
Financial charges of joint ventures	(59)	(4)		(63)
Equity income	83	130		213
Interest income and other	8	14	37	59
Gains on sale of assets	7	197		204
Income taxes	(430)	(104)	43	(491)
Net income from continuing operations	586	396	(2)	980
Net income from discontinued operations				52

Net Income	1,032

Year ended December 31, 2003 (millions of dollars)

Revenues	3,968	1,668		5,636
Cost of sales[2]		(979)		(979)
Other costs and expenses	(1,274)	(385)	(7)	(1,666)
Depreciation	(834)	(82)	(1)	(917)
Operating income/(loss)	1,860	222	(8)	2,074
Financial charges and non-controlling interests	(845)	(11)	(89)	(945)
Financial charges of joint ventures	(79)	(1)		(80)
Equity income	107	99		206
Interest income and other	17	14	29	60
Income taxes	(438)	(103)	27	(514)
Net income from continuing operations	622	220	(41)	801

Net income from discontinued operations	50
Net Income	851

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

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

TOTAL ASSETS

December 31 (millions of dollars)	**2005**	2004
Gas Transmission	**18,252**	18,720
Power	**4,923**	2,802
Corporate	**938**	900
	24,113	22,422

GEOGRAPHIC INFORMATION

Year ended December 31 (millions of dollars)	**2005**	2004	2003
Revenues[3]			
Canada domestic	**3,499**	3,214	3,324
Canada export	**1,160**	1,261	1,293
United States	**1,465**	1,022	1,019
	6,124	5,497	5,636

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

PLANT, PROPERTY AND EQUIPMENT

December 31 (millions of dollars)	**2005**	2004
Canada	**15,647**	14,757
United States	**4,306**	4,007
Mexico	**85**	
	20,038	18,764

CAPITAL EXPENDITURES

Year ended December 31 (millions of dollars)	**2005**	2004	2003

Gas Transmission	**377**	241	260
Power	**373**	285	132
Corporate	**4**	4	3
	754	530	395

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS **85**

NOTE 4 PLANT, PROPERTY AND EQUIPMENT

December 31 (millions of dollars)	2005 Cost	2005 Accumulated Depreciation	2005 Net Book Value	2004 Cost	2004 Accumulated Depreciation	2004 Net Book Value
Gas Transmission						
Canadian Mainline						
Pipeline	8,701	3,665	5,036	8,695	3,421	5,274
Compression	3,341	1,066	2,275	3,322	947	2,375
Metering and other	359	134	225	366	125	241
	12,401	4,865	7,536	12,383	4,493	7,890
Under construction	15		15	16		16
	12,416	4,865	7,551	12,399	4,493	7,906
Alberta System						
Pipeline	5,020	2,203	2,817	4,978	2,055	2,923
Compression	1,493	676	817	1,496	599	897
Metering and other	799	247	552	861	262	599
	7,312	3,126	4,186	7,335	2,916	4,419
Under construction	25		25	20		20
	7,337	3,126	4,211	7,355	2,916	4,439
GTN[1]						
Pipeline	1,381	60	1,321	1,417	8	1,409
Compression	507	15	492	526	2	524
Metering and other	90		90	101	2	99
	1,978	75	1,903	2,044	12	2,032
Under construction	18		18	17		17
	1,996	75	1,921	2,061	12	2,049
Foothills System						
Pipeline	815	377	438	815	346	469
Compression	373	128	245	373	114	259
Metering and other	75	31	44	78	35	43
	1,263	536	727	1,266	495	771
Joint Ventures and other[2]	3,491	1,127	2,364	3,293	1,073	2,220
	26,503	9,729	16,774	26,374	8,989	17,385
Power[3]						
Nuclear[4]	1,265	143	1,122			
Natural gas	1,121	347	774	1,333	374	959
Hydro	598	9	589	61	1	60
Other	67	36	31	67	32	35
	3,051	535	2,516	1,461	407	1,054

Under construction	**721**		**721**	288		288
	3,772	**535**	**3,237**	1,749	407	1,342
Corporate	**73**	**46**	**27**	124	87	37
	30,348	**10,310**	**20,038**	28,247	9,483	18,764

(1) Gas Transmission Northwest System and North Baja System (collectively GTN).

(2) The December 31, 2005 net book value includes $235 million of plant, property and equipment under construction (2004 $20 million).

(3) Certain Power generation facilities are accounted for as assets under operating leases. At December 31, 2005, the net book value of these facilities was $87 million (2004 $70 million). In 2005, revenues of $23 million (2004 $7 million) were recognized through the sale of electricity under the related PPAs.

(4) Assets under capital lease relating to Bruce Power. The Company proportionately consolidated its ownership interest in Bruce Power, on a prospective basis, effective October 31, 2005.

NOTE 5 OTHER ASSETS

December 31 (millions of dollars)	**2005**	2004
Derivative contracts	**209**	180
Hedging deferrals	**118**	50
PPAs Canada[1]	**825**	274
PPAs U.S.[1]		98
Pension and other benefit plans	**304**	253
Regulatory assets	**183**	174
Loans and advances[2]	**91**	135
Goodwill	**57**	58
Debt issue costs	**48**	50
Other	**274**	187
	2,109	1,459

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

	2005			**2004**		
December 31 (millions of dollars)	**Cost**	**Accumulated Amortization**	**Net Book Value**	Cost	Accumulated Amortization	Net Book Value
PPAs Canada	**915**	**90**	**825**	345	71	274
PPAs U.S.				102	4	98

The aggregate amortization expense with respect to the PPAs was $24 million for the year ended December 31, 2005 (2004 $24 million; 2003 $37 million). The amortization expense with respect to the PPAs approximates: 2006 $58 million; 2007 $58 million; 2008 $58 million; 2009 $58 million; and 2010 $58 million. In August 2005, the Company sold TransCanada Power, L.P. (Power LP), which included 100 per cent of the PPAs U.S. Effective December 31, 2005, the Company acquired the remaining rights and obligations for the remaining 15 years of the Sheerness PPA for $585 million.

(2) The December 31, 2004 balance includes a $75 million unsecured note receivable from Bruce B bearing interest at 10.5 per cent per annum, due February 14, 2008. Effective October 31, 2005, the Company proportionately consolidated its investment in Bruce B and this balance is eliminated upon consolidation. The December 31, 2005 balance includes an $87 million loan (2004 $60 million) to the Aboriginal Pipeline Group (APG) to finance the APG for its one-third share of project development costs related to the Mackenzie Gas Pipeline Project.

NOTE 6 JOINT VENTURE INVESTMENTS

	TransCanada's Proportionate Share

(millions of dollars)	Ownership Interest	Income Before Income Taxes Year Ended December 31			Net Assets December 31	
		2005	2004	2003	**2005**	2004
Gas Transmission						
Great Lakes	50.0%(1)	**73**	86	81	**375**	379
Iroquois	44.5%(1)(2)	**29**	28	31	**190**	175
Trans Québec & Maritimes	50.0%	**13**	13	14	**73**	75
CrossAlta	60.0%(1)	**31**	20	11	**30**	24
Foothills	(3)			19		
Other	Various	**15**	12	12	**67**	67
Power						
Bruce A	47.9%(4)	**19**			**563**	
Bruce B	31.6%(4)	**5**			**434**	
ASTC Power Partnership	50.0%(5)				**88**	93
Power LP	(6)	**25**	32	25		289
		210	191	193	**1,820**	1,102

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

(2) In June 2005, the Company acquired an additional 3.5 per cent ownership interest in Iroquois.

(3) In August 2003, the Company acquired the remaining interests in Foothills Pipe Lines Ltd. and its subsidiaries (Foothills) previously not held by TransCanada, and Foothills was consolidated subsequent to that date.

(4) TransCanada acquired a 47.4 per cent ownership interest in Bruce A on October 31, 2005 and a 31.6 per cent ownership interest in Bruce B in February 2003. The Company increased its ownership interest in Bruce A to 47.9 per cent during the remainder of 2005 as a result of certain other partners not participating in capital contributions to Bruce A. The Company proportionately consolidated its investments in Bruce A and Bruce B, on a prospective basis, effective October 31, 2005.

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

(6) In April 2004, the Company's interest in Power LP decreased to 30.6 per cent from 35.6 per cent. In August 2005, the Company sold its 30.6 per cent interest in Power LP.

Consolidated retained earnings at December 31, 2005 include undistributed earnings from these joint ventures of $765 million (2004 $473 million).

Summarized Financial Information of Joint Ventures

Year ended December 31 (millions of dollars)	**2005**	2004	2003
Income			
Revenues	**687**	572	635
Other costs and expenses	**(328)**	(240)	(278)
Depreciation	**(93)**	(90)	(98)
Financial charges and other	**(56)**	(51)	(66)
Proportionate share of income before income taxes of joint ventures	**210**	191	193

Year ended December 31 (millions of dollars)	**2005**	2004	2003
Cash Flows			
Operations	**346**	270	259
Investing activities	**(133)**	(287)	(139)
Financing activities[1]	**(152)**	35	(115)
Effect of foreign exchange rate changes on cash and short-term investments	**(1)**	(5)	(12)
Proportionate share of increase/(decrease) in cash and short-term investments of joint ventures	**60**	13	(7)

(1) Financing activities include cash outflows resulting from distributions paid to TransCanada of $201 million (2004 $158 million; 2003 $103 million), and cash inflows resulting from capital contributions paid by TransCanada of $92 million (2004 and 2003 nil).

December 31 (millions of dollars)	**2005**	2004
Balance Sheet		
Cash and short-term investments	**123**	63
Other current assets	**281**	122
Plant, property and equipment	**2,707**	1,708
Current liabilities	**(291)**	(155)
(Deferred amounts)/other assets (net)	**(45)**	221
Long-term debt of joint ventures	**(937)**	(808)

Future income taxes	**(18)**	(49)
Proportionate share of net assets of joint ventures	**1,820**	1,102

NOTE 7 LONG-TERM INVESTMENTS

		TransCanada's Share							
		Distributions from Equity Investments Year Ended December 31			Income from Equity Investments Year Ended December 31			Equity Investments December 31	
(millions of dollars)	Ownership Interest	**2005**	2004	2003	**2005**	2004	2003	**2005**	2004
Gas Transmission									
Northern Border	(1)	**76**	79	65	**61**	65	63	**315**	349
TransGas	46.5%(2)	**6**	8	8	**11**	11	27	**62**	78
Portland	61.7%(3)			10			14		
Other	Various	**10**	13	6	**7**	7	3	**23**	29
Power									
Bruce B	31.6%(4)	**84**			**168**	130	99		642
		176	100	89	**247**	213	206	**400**	1,098

(1) The Company consolidates PipeLines LP, which holds a 30.0 per cent interest in Northern Border Pipeline Company (Northern Border). The amounts presented represent a 30.0 per cent interest, however, the Company's effective ownership interest in Northern Border, net of non-controlling interests, is 4.0 per cent as a result of the Company holding a 13.4 per cent interest in PipeLines LP. The Company's effective ownership interest in Northern Border was reduced from 10.0 per cent to 4.0 per cent in a series of transactions related to PipeLines LP in March and April 2005.

(2) TransGas de Occidente S.A. (TransGas).

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

(4) The Company proportionately consolidated its 31.6 per cent ownership interest in Bruce B, on a prospective basis, effective October 31, 2005.

Consolidated retained earnings at December 31, 2005 include undistributed earnings from these equity investments of $55 million (2004 $294 million).

NOTE 8 ACQUISITIONS AND DISPOSITIONS

Acquisitions

Sheerness PPA

Effective December 31, 2005, TransCanada acquired the remaining rights and obligations of the Sheerness PPA from the Alberta Balancing Pool for $585 million. There is approximately a 15 year term remaining on the PPA.

Bruce Power

In February 2003, the Company acquired a 31.6 per cent partnership interest in Bruce B for $409 million, which at that time owned the currently idle Bruce A Units 1 and 2 as well as the currently operating Bruce A Units 3 and 4 and Bruce B Units 5 to 8. The Company accounted for this as an equity investment. On October 31, 2005, as part of an agreement to restart the currently idle Bruce A Units 1 and 2, TransCanada acquired a partnership interest in a newly created

partnership, Bruce A, which subleased the Bruce A Units 1 to 4 from Bruce B (the Bruce A Sublease) and purchased certain other related assets. TransCanada incurred a net cash outlay of $100 million as a result of this transaction and as at December 31, 2005 held a 47.9 per cent interest in Bruce A. As part of this reorganization, both Bruce A and Bruce B became jointly controlled entities and TransCanada commenced proportionately consolidating its investments in both Bruce A and Bruce B, on a prospective basis, effective October 31, 2005.

TC Hydro

In April 2005, TransCanada acquired certain hydroelectric generation assets from USGen New England, Inc. for approximately US$503 million. Substantially all of the purchase price was allocated to plant, property and equipment. The financial results from these assets have been included in the Power segment as of the date of acquisition.

GTN

In November 2004, TransCanada acquired GTN for US$1,728 million, including US$528 million of assumed debt and closing adjustments. The purchase price was allocated as follows using fair values of the net assets at the date of acquisition.

Purchase Price Allocation

(millions of U.S. dollars)

Current assets	40
Plant, property and equipment	1,718
Other non-current assets	21
Goodwill	48
Current liabilities	(48)
Long-term debt	(528)
Other non-current liabilities	(51)
	1,200

Goodwill, which is attributable to the North Baja System, is re-evaluated on an annual basis for impairment. Factors that contributed to goodwill include opportunities for expansion, a strong competitive position, strong demand for natural gas in the western markets and access to an ample supply of relatively low-cost natural gas. The goodwill recognized on this transaction is being amortized for tax purposes over 15 years.

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

Dispositions

The pre-tax gains on sale of assets are comprised of the following.

Year ended December 31 (millions of dollars)	**2005**	2004
Gains related to Power LP	**245**	197
Gain on sale of Paiton Energy[(1)]	**118**	
Gain on sale of PipeLines LP units	**82**	
Gain on sale of Millennium[(1)]		7
	445	204

(1) PT Paiton Energy Company (Paiton Energy); Millennium Pipeline project (Millennium).

Power LP

In August 2005, TransCanada sold its ownership interest in Power LP to EPCOR Utilities Inc. (EPCOR) for net proceeds of $523 million and realized an after-tax gain of $193 million. The net gain was recorded in the Power segment and the Company recorded a $52 million income tax charge, including $79 million of current income tax expense, on this transaction. The book value of Power LP's assets and liabilities disposed of under this sale were $452 million and $174 million, respectively. EPCOR's acquisition included 14.5 million limited partnership units of Power LP, representing 30.6 per cent of the outstanding units; 100 per cent ownership of the general partner of Power LP; and the management and operations agreements governing the ongoing operation of Power LP's

generation assets.

In April 2004, TransCanada sold the ManChief and Curtis Palmer power facilities to Power LP for US$402.6 million, plus closing adjustments of US$12.8 million, and recognized an after-tax gain on sale of $15 million. The net gain was recorded in the Power segment and the Company recorded a $10 million income tax charge.

At a special meeting held in April 2004, Power LP's unitholders approved an amendment to the terms of the Power LP Partnership Agreement to remove Power LP's obligation to redeem all units not owned by TransCanada at June 30, 2017. TransCanada was required to fund this redemption, thus the removal of Power LP's obligation eliminated this requirement. The removal of the obligation and the reduction in TransCanada's ownership interest in Power LP resulted in a gain of $172 million.

Paiton Energy

In November 2005, TransCanada sold its approximate 11 per cent ownership interest in Paiton Energy to subsidiaries of The Tokyo Electric Power Company for gross proceeds of US$103 million ($122 million). The book value of Paiton Energy at the time of sale was nil and TransCanada realized an after-tax gain on sale of $115 million. The net gain was recorded in the Power segment and the Company recorded a $3 million income tax charge, including $3 million of current income tax recovery.

PipeLines LP

In March and April 2005, TransCanada sold 3,574,200 common units of PipeLines LP for net proceeds of $153 million and recorded an after-tax gain of $49 million. The net gain was recorded in the Gas Transmission segment and the company recorded a $33 million income tax charge, including $51 million of current income tax expense, on this transaction. Subsequent to these transactions, TransCanada continues to own a 13.4 per cent interest in PipeLines LP represented by a general partner interest of 2.0 per cent and an 11.4 per cent limited partner interest.

NOTE 9 LONG-TERM DEBT

		2005		2004	
	Maturity Dates	Outstanding December 31[1]	Weighted Average Interest Rate[2]	Outstanding December 31[1]	Weighted Average Interest Rate[2]
CANADIAN MAINLINE[4]					
First Mortgage Pipe Line Bonds					
Pounds Sterling (2005 and 2004 £25)	2007	**50**	**16.5%**	58	16.5%
Debentures					
Canadian dollars	2008 to 2020	**1,354**	**10.9%**	1,354	10.9%
U.S. dollars (2005 and 2004 US$600)[3]	2012 to 2021	**702**	**9.5%**	722	9.5%
Medium-Term Notes					
Canadian dollars	2006 to 2031	**1,987**	**7.1%**	2,167	6.9%
U.S. dollars (2005 and 2004 US$120)	2010	**140**	**6.1%**	144	6.1%
		4,233		4,445	
ALBERTA SYSTEM[5]					
Debentures and Notes					
Canadian dollars	2007 to 2024	**585**	**11.6%**	607	11.6%
U.S. dollars (2005 and 2004 US$375)	2012 to 2023	**437**	**8.2%**	451	8.2%
Medium-Term Notes					
Canadian dollars	2006 to 2030	**964**	**6.6%**	767	7.4%
U.S. dollars (2005 and 2004 US$233)	2026 to 2029	**272**	**7.7%**	280	7.7%
		2,258		2,105	
GTN[6]					
Unsecured Debentures and Notes (2005 US$400; 2004 US$525)	2010 to 2035	**466**	**5.3%**	632	7.2%
FOOTHILLS SYSTEM[4]					
Senior Unsecured Notes	2009 to 2014	**400**	**4.9%**	400	4.9%
PORTLAND[7]					
Senior Secured Notes					
U.S. dollars (2005 US$241; 2004 US$256)	2018	**281**	**5.9%**	308	5.9%
OTHER					
Medium-Term Notes[4]					
Canadian dollars	2014 to 2030	**542**	**5.9%**	592	6.2%
U.S. dollars (2005 and 2004 US$521)	2006 to 2025	**607**	**6.9%**	627	6.9%
Subordinated Debentures[4]					
U.S. dollars (2005 and 2004 US$57)	2006	**66**	**9.1%**	68	9.1%
Unsecured Loans, Debentures and Notes[3][8]					
U.S. dollars (2005 US$1,014; 2004 US$1,119)	2006 to 2034	**1,180**	**4.8%**	1,346	5.0%

	2,395	2,633
	10,033	10,523
Less: Current Portion of Long-Term Debt	**393**	774
	9,640	9,749

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

(2) Weighted average interest rates are stated as at the respective outstanding dates. The effective weighted average interest rates resulting from swap agreements are as follows: Other U.S. dollar subordinated debentures 9.0 per cent (2004 9.0 per cent); and Other U.S. dollar unsecured loans, debentures and notes 4.9 per cent (2004 5.1 per cent).

(3) In 2005, under agreement with shippers, TransCanada PipeLines Limited (TCPL) effectively fixed the exchange rate on the US$600 million debentures for regulatory purposes. The exchange differential on the long-term debt at December 31, 2005, is $(2) million and is included as part of Other U.S. dollar unsecured loans, debentures and notes.

(4) Long-term debt of TCPL.

(5) Long-term debt of NOVA Gas Transmission Ltd. excluding two medium-term notes held by TCPL: a $300 million note (2004 nil) and a $233 million note (US$200 million) (2004 $241 million (US$200 million)).

(6) Long-term debt of Gas Transmission Northwest Corporation.

(7) Long-term debt of Portland.

(8) Long-term debt of TCPL, excluding $16 million (2004 $44 million) issued by PipeLines LP.

Principal Repayments

Principal repayments on the long-term debt of the Company approximate: 2006 $393 million; 2007 $604 million; 2008 $547 million; 2009 $742 million; and 2010 $416 million.

Debt Shelf Programs

At December 31, 2005, $1.2 billion of medium-term note debentures could be issued under a base shelf program in Canada and US$1 billion of debt securities could be issued under a debt shelf program in the U.S. In January 2006, the Company issued $300 million of five year medium-term notes bearing interest of 4.3 per cent under the Canadian base shelf program.

CANADIAN MAINLINE

First Mortgage Pipe Line Bonds

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

ALBERTA SYSTEM

Debentures

Debentures amounting to $225 million have retraction provisions which entitle the holders to require redemption of up to eight per cent of the then outstanding principal plus accrued and unpaid interest on specified repayment dates. No redemptions have been made to December 31, 2005.

Medium-Term Notes

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

Financial Charges

Year ended December 31 (millions of dollars)	**2005**	2004	2003
Interest on long-term debt	**849**	864	867
Interest on short-term debt	**23**	7	16
Capitalized interest	**(24)**	(11)	(9)
Amortizations and other financial charges	**(12)**	(2)	4

	836	858	878

The Company made interest payments of $838 million for the year ended December 31, 2005 (2004 $864 million; 2003 $903 million).

NOTE 10 LONG-TERM DEBT OF JOINT VENTURES

		2005		2004	
	Maturity Dates	Outstanding December 31[1]	Weighted Average Interest Rate[2]	Outstanding December 31[1]	Weighted Average Interest Rate[2]
Great Lakes					
Senior Unsecured Notes (2005 US$230; 2004 US$235)	2011 to 2030	268	7.9%	283	7.9%
Bruce Power					
Capital Lease Obligations	2018	254	7.5%		
Iroquois					
Senior Unsecured Notes (2005 US $165; 2004 US$151)	2010 to 2027	192	7.5%	182	7.5%
Bank Loan (2005 US$25; 2004 US$36)	2008	29	4.3%	43	2.5%
Trans Québec & Maritimes					
Bonds	2009 to 2010	138	6.0%	143	7.3%
Term Loan	2010	29	3.5%	29	3.2%
Power L.P.[3]					
Senior Unsecured Notes (2004 US$58)				70	5.9%
Credit Facility				64	3.2%
Term Loan				2	11.3%
Other	2006 to 2012	68	6.1%	77	5.8%
		978		893	
Less: Current Portion of Long-Term Debt of Joint Ventures		41		85	
		937		808	

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

(2) Weighted average interest rates are stated as at the respective outstanding dates. At December 31, 2005, the effective weighted average interest rates resulting from swap agreements are as follows: Iroquois bank loan 5.4 per cent (2004 4.1 per cent).

(3) In August 2005, the Company sold its ownership interest in Power LP.

The long-term debt of joint ventures is non-recourse to TransCanada, except that TransCanada has provided certain pro-rata guarantees related to the capital lease obligations of Bruce Power. The security provided with respect to the debt by each joint venture is limited to the rights and assets of that joint venture and does not extend to the rights and assets of TransCanada, except to the extent of TransCanada's investment.

The Company's proportionate share of principal repayments resulting from maturities and sinking fund obligations of the non-recourse joint venture debt approximates: 2006 $34 million; 2007 $20 million; 2008 $20 million; 2009 $78 million; and 2010 $273 million.

The Company's proportionate share of principal payments resulting from the capital lease obligations of Bruce Power approximates: 2006 $7 million; 2007 $8 million; 2008 $9 million; 2009 $11 million; and 2010 $13 million.

Financial Charges of Joint Ventures

Year ended December 31 (millions of dollars)	**2005**	2004	2003
Interest on long-term debt	**60**	59	77
Interest on capital lease obligations	**3**		
Interest on short-term debt and other financial charges	**1**	2	1
Deferrals and amortizations	**2**	2	2
	66	63	80

The Company's proportionate share of the interest payments of joint ventures was $62 million for the year ended December 31, 2005 (2004 $58 million; 2003 $71 million).

The Company's proportionate share of interest payments from the capital lease obligations of Bruce Power was $3 million for the year ended December 31, 2005 (2004 and 2003 nil).

Subject to meeting certain requirements, the Bruce Power capital lease agreements provide for renewals commencing January 1, 2019. The first renewal is for a period of one year, and each of the second to thirteenth renewals is for a period of two years.

NOTE 11 DEFERRED AMOUNTS

December 31 (millions of dollars)	**2005**	2004
Derivative contracts	**212**	135
Hedging deferrals	**72**	53
Regulatory liabilities	**597**	392
Pensions and other benefit plans	**168**	82
Deferred revenue	**42**	58
Asset retirement obligations	**33**	36
Other	**72**	27
	1,196	783

NOTE 12 REGULATED BUSINESS

Regulatory assets and liabilities represent future revenues which are expected to be recovered from or refunded to customers in future periods through the rate-setting process associated with certain costs, incurred in the current period or in prior periods, and under or over collection of revenues.

Canadian Regulated Operations

Canadian natural gas transmission services are provided under gas transportation tariffs that provide for cost recovery including return of and return on capital as approved by the applicable regulatory authorities.

Rates charged by TransCanada's wholly-owned and partially-owned Canadian pipelines are typically set through a process that involves filing an application for a change in rates with the regulator. Under the regulation, rates are underpinned by the total annual revenue requirement which includes a specified annual return on capital, including debt and equity, and all necessary operating expenses, taxes and depreciation.

TransCanada's Canadian regulated pipelines have generally been regulated using a cost-of-service model, where the forecast costs plus a return on capital equals the revenues for the upcoming year. To the extent that actual costs are more or less than the forecast costs, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in revenues at that time. Those costs, for which the regulator does not allow the difference between actual and forecast costs to be deferred, are included in the determination of net income in the year in which they are incurred.

The Canadian Mainline, the BC System, the Foothills System and the TransQuébec & Maritimes System (TQM) are regulated by the NEB under the National Energy Board Act. The Alberta System is regulated by the EUB primarily under the provisions of the Gas Utilities Act (Alberta) and the Pipeline Act (Alberta). The NEB and the EUB regulate the construction, operations, tolls and the determination of revenues of the Canadian natural gas transmission operations.

Canadian Mainline

In February 2005, TransCanada and its Canadian Mainline shippers entered into a negotiated settlement that addresses all elements of the Canadian Mainline's 2005 tolls (2005 Settlement). The 2005 Settlement was approved by the NEB in April 2005. Pursuant to the 2005 Settlement, the cost of capital of the Canadian Mainline's 2005 revenue requirement and resulting tolls were determined based on the RH-2-2004 Phase II proceeding relating to the 2004 cost of capital of the Canadian Mainline. The RH-2-2004 Phase II decision increased the deemed capital structure for the Canadian Mainline to 36 per cent from 33 per cent, effective January 1, 2004. The impact of this has been recognized in 2005. The return on equity of the Canadian Mainline continues to be based on the NEB's approved rate of return on common equity (ROE) formula which was established in the RH-2-94 Multi-Pipeline Cost of Capital proceeding.

Under the 2005 Settlement, the Canadian Mainline's operations, maintenance and administrative (OM&A) costs for 2005 were fixed and variances between the 2005 negotiated and actual level of OM&A costs accrued to TransCanada. All other cost and revenue component variances were treated on a full recovery basis. The allowed ROE in 2005 was 9.46 per cent.

Alberta System

The Alberta System operates under the 2005-2007 Revenue Requirement Settlement. This settlement, approved by the EUB in June 2005, encompassed all elements of the Alberta System's revenue requirement for 2005, 2006 and 2007 and established methodologies for calculation of the revenue requirement for all three years, based on the recovery of all cost components and the use of deferral accounts.

Fixed costs are operating costs and certain other costs, including foreign exchange on interest payments, uninsured losses and amortization of severance costs. These costs were set for each year for 2005, 2006 and 2007 and any difference between actual and forecast fixed costs will be included in the determination of net income in the year in which they are incurred. Costs other than fixed costs are forecast at the beginning of each year and included in the calculation of the revenue requirement. Any variance between the forecast and actual costs incurred will be included in a deferral account and adjusted in the following year's revenue requirement. The settlement also set the ROE using the formula for determining the annual generic rate of return on common equity established in the EUB's General Cost of Capital Decision 2004-052 on a deemed common equity of 35 per cent for all three years. The allowed ROE in 2005 was 9.50 per cent.

Other Canadian Pipelines

Similar to the Canadian Mainline, the NEB approves pipeline tolls on an annual cost of service basis for the BC System, Foothills System and TQM. The NEB allows each pipeline to charge a schedule of tolls based on the estimated cost of service. This schedule of tolls is used for a current year until a new toll filing is made for the following year. Differences between the estimated cost of service and the actual cost of service are included in the following year's tolls. The ROE for these Canadian pipelines is based on the NEB's approved ROE formula which was established in the RH-2-94 Multi-Pipeline Cost of Capital proceeding, being 9.46 per cent in 2005. The deemed equity component of each of the pipelines' capital structure was set at 30 per cent for 2005.

U.S. Regulated Operations

TransCanada's wholly-owned and partially-owned U.S. pipelines, including Great Lakes, Iroquois, Portland, Northern Border and Tuscarora Gas Transmission System, are 'natural gas companies' operating under the provisions of the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, and are subject to the jurisdiction of the FERC. The Natural Gas Act of 1938 grants the FERC authority over the construction and operation of pipelines and related facilities. The FERC also has authority to regulate rates for natural gas transportation in interstate commerce.

Gas Transmission Northwest System and North Baja System

Rates and tariffs of the Gas Transmission Northwest System and the North Baja System have been approved by the FERC. These two systems operate under fixed rate models, whereby maximum and minimum rates for various service types have been ordered by FERC and under which each of the two systems are permitted to discount or negotiate rates on a non-discriminatory basis. General rates for mainline capacity on the Gas Transmission Northwest System were last reviewed by the FERC in a 1994 rate proceeding. A settlement of the 1994 rate proceeding, which set rate levels that remain in effect today, was approved by the FERC in 1996. Rates for capacity on the North Baja System were established in the FERC's initial order certificating construction and operations of its system.

Portland

In 2003, Portland received final approval from FERC of its general rate case under the Natural Gas Act of 1938. Portland is required to file a general rate case under the Natural Gas Act of 1938 with a proposed effective date of April 1, 2008.

Regulatory Assets and Liabilities

Year ended December 31 (millions of dollars)	2005	2004	Remaining Recovery/ Settlement Period
			(years)
Regulatory Assets			
Unrealized losses on derivatives Canadian Mainline[1]	**43**	35	2 - 5
Unrealized losses on derivatives BC System[1]	**33**	25	8
Foreign exchange Alberta System[2]	**32**	33	24
Contractor claim Trans Québec & Maritimes[3]		16	n/a
Phase II Preliminary Expenditures Foothills System[4]	**23**	25	10
Deferred charge on reacquired debt Gas Transmission Northwest System[5]	**14**	6	4 - 20
Transitional other benefit obligations Canadian Mainline[6]	**10**	11	11
Other	**28**	23	3 - 11
Total Regulatory Assets (Other Assets)	**183**	174	
Regulatory Liabilities			
Operating and debt service regulatory liabilities[7]	**273**	146	1
Foreign exchange on long-term debt Canadian Mainline[2]	**202**	153	2 - 42
Foreign exchange on long-term debt Alberta System[2]	**59**	36	7 - 24
Foreign exchange on long-term debt BC System[2]	**20**	16	8
Post-retirement benefits other than pension Gas Transmission Northwest System[8]	**17**	15	n/a
Other	**26**	26	n/a
Total Regulatory Liabilities (Deferred Amounts)	**597**	392	

(1) Unrealized losses on derivatives represent the net position of fair value gains and losses on cross-currency and interest rate swaps which act as economic hedges. The cross-currency swaps relate to Canadian Mainline and BC System foreign debt instruments. The Canadian Mainline interest rate swaps were entered into as a result of the Interest Rate Management Program approved by the NEB as a component of the 1996 - 1999 Incentive Cost Recovery and Revenue Settlement. Interest savings or losses are determined when the interest swaps are settled. In the absence of rate regulation accounting, Canadian GAAP would require the inclusion of these fair value losses in the operating results as they were not documented as hedges for accounting purposes. In the absence of rate regulation accounting, pre-tax operating results for 2005 would have been $8 million lower for each of the Canadian Mainline and the BC System.

(2) The foreign exchange reserve account in the Alberta System, as approved by the EUB, is designed to facilitate the recovery or refund of foreign exchange gains and losses over the life of the foreign currency debt issues. Each year, the estimated gain/(loss) on foreign currency debt is amortized over the remaining years of the longest outstanding U.S. debt issue. The annual amortization amount is included in the determination of tolls for the year. The foreign exchange on long-term debt on the Canadian Mainline, Alberta System and BC System represent the variance resulting from re-valuing foreign currency denominated debt instruments from their historic foreign exchange rate to the current foreign exchange rate. Foreign exchange gains/(losses) realized when foreign debt matures or is redeemed early are expected to be recovered through the determination of future tolls. In the absence of rate regulation accounting, GAAP would have required the inclusion of these unrealized gains or losses either on the balance sheet or

income statement depending on whether the foreign debt is designated as a hedge of the Company's net investment in foreign assets.

(3)

As at December 31, 2004, Trans Québec & Maritimes had deferred $32 million related to a contractor claim regarding cost overruns on an extension project to Portland. TransCanada's share of this deferral was $16 million. In 2005, the NEB approved Trans Québec & Maritimes 2005 tolls application as filed which allowed for this amount to be capitalized in 2005. This amount would have been capitalized under GAAP.

(4)

Phase II Preliminary Expenditures are costs incurred by Foothills System prior to 1981 related to development of Canadian facilities to deliver Alaskan natural gas that have been approved by the regulator for collection through straight-line amortization over the period November 1, 2002 to December 31, 2015. In the absence of rate regulation accounting, GAAP would have required these costs to be expensed in the year incurred, increasing pre-tax operating results in 2005 by $2 million.

(5)

Deferred charge on reacquired debt includes the unamortized debt issuance costs and premiums or discounts on Gas Transmission Northwest System debt that was reacquired prior to its original maturity date, along with any costs incurred or gains realized on reacquiring this debt. These amounts continue to be amortized over the original life of the debt that has been reacquired. In the absence of rate regulation accounting, GAAP would require the inclusion of these costs in the operating results to the extent that the debt has

not been renegotiated. Consequently, pre-tax operating results in 2005 are $8 million higher than would have been reported in the absence of rate regulation accounting.

(6) The regulatory asset with respect to the transitional other benefit obligations is being amortized over 17 years, starting January 1, 2000. Amortization will be completed by December 31, 2016, at which time the full transitional obligation will have been recovered through tolls. In the absence of rate regulation accounting, pre-tax operating results would have been $1 million higher.

(7) Operating and debt service regulatory liabilities represent the accumulation of cost and revenue variances approved by the regulatory authority for inclusion in determination of the tolls for the immediately following calendar year. In the absence of rate regulation accounting, GAAP may require the inclusion of these variances in the operating results of the year in which the variances were incurred. Pre-tax operating results for 2005 are the same as would have been the case in the absence of rate regulation accounting.

(8) In Gas Transmission Northwest System's rates, an amount is recovered for post-retirement benefits other than pension (PBOP). This regulatory liability represents the difference between the amount collected in rates and the amount of PBOP expense determined under GAAP. In the absence of rate regulation accounting, GAAP would require the inclusion of this amount in operating results and pre-tax operating results in 2005 would have been $2 million higher than reported.

As prescribed by the regulators, the taxes payable method of accounting for income taxes is used for tollmaking purposes for Canadian regulated natural gas transmission operations. As permitted by GAAP, this method is also used for accounting purposes, since there is reasonable expectation that future income taxes payable will be included in future costs of service and recorded in revenues at that time. Consequently, future income tax liabilities have not been recognized as it is expected that when these amounts become payable, they will be recovered through future rate revenues. In the absence of rate regulation accounting, GAAP would require the recognition of future income tax liabilities. If the liability method of accounting had been used, additional future income tax liabilities in the amount of $1,619 million at December 31, 2005 (2004 $1,692 million) would have been recorded. For the U.S. natural gas transmission operations, the liability method of accounting is used for both accounting and tollmaking purposes, whereby future income tax assets and liabilities are recognized based on the differences between financial statement carrying amounts and the tax basis of such assets and liabilities. As this method is also used for tollmaking purposes for the U.S. natural gas transmission operations, the current year's revenues include a tax provision which is calculated based on the liability method of accounting and therefore, there is no recognition of a related regulatory asset or liability.

NOTE 13 PREFERRED SECURITIES

The US$460 million (2005 $536 million; 2004 $554 million) 8.25 per cent preferred securities of TCPL are redeemable by the issuer at par at any time. The issuer may elect to defer interest payments on the Preferred Securities and settle the deferred interest in either cash or common shares.

NOTE 14 NON-CONTROLLING INTERESTS

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

December 31 (millions of dollars)	**2005**	2004
Preferred shares of subsidiary	**389**	389
Non-controlling interest in PipeLines LP	**318**	235
Other	**76**	76
	783	700

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

Year ended December 31 (millions of dollars)	**2005**	2004	2003
Preferred share dividends of subsidiary	**22**	22	22
Non-controlling interest in PipeLines LP	**52**	46	43

Other	**10**	10	2
	84	78	67

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Preferred Shares of Subsidiary

December 31	Number of Shares	Dividend Rate Per Share	Redemption Price Per Share	**2005**	2004
	(thousands)			(millions of dollars)	(millions of dollars)
Cumulative First Preferred Shares of Subsidiary					
Series U	4,000	$2.80	$50.00	**195**	195
Series Y	4,000	$2.80	$50.00	**194**	194
				389	389

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

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

At December 31, 2005, the non-controlling interest in PipeLines LP is 86.6 per cent. Other non-controlling interests at December 31, 2005 include the 38.3 per cent non-controlling interest in Portland. Revenues received from PipeLines LP and Portland with respect to services provided by TransCanada for the year ended December 31, 2005 were $1 million (2004 $1 million; 2003 $1 million) and $6 million (2004 $4 million; 2003 nil), respectively.

NOTE 15 COMMON SHARES

	Number of Shares	Amount
	(thousands)	(millions of dollars)
Outstanding at January 1, 2003	479,502	4,614
Exercise of options	3,698	65
Outstanding at December 31, 2003	483,200	4,679
Exercise of options	1,714	32
Outstanding at December 31, 2004	484,914	4,711
Exercise of options	**2,322**	**44**
Outstanding at December 31, 2005	**487,236**	**4,755**

Common Shares Issued and Outstanding

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

Net Income Per Share

Basic and diluted earnings per share are calculated based on the weighted average number of common shares outstanding during the year of 486.2 million and 489.1 million (2004 484.1 million and 486.7 million; 2003 481.5 million and 483.9 million), respectively. The increase in the weighted average number of shares for the diluted earnings per share calculation is due to the options exercisable under TransCanada's Stock Option Plan.

Stock Options

	Number of Options	Weighted Average Exercise Prices	Options Exercisable
	(thousands)		(thousands)
Outstanding at January 1, 2003	12,892	$18.92	10,258
Granted	1,503	$22.42	
Exercised	(3,698)	$17.59	
Cancelled or expired	(342)	$24.07	
Outstanding at December 31, 2003	10,355	$19.73	7,588
Granted	1,331	$26.85	
Exercised	(1,714)	$18.42	
Cancelled or expired	(7)	$24.25	
Outstanding at December 31, 2004	9,965	$20.90	7,239
Granted	**1,075**	**$30.21**	
Exercised	**(2,322)**	**$18.57**	
Cancelled or expired	**(4)**	**$25.34**	
Outstanding at December 31, 2005	**8,714**	**$22.67**	**6,300**

The following table summarizes information for stock options outstanding at December 31, 2005.

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
	(thousands)	(years)		(thousands)	
$10.03 to $18.01	1,347	4.9	$15.64	1,347	$15.64
$18.81 to $20.59	1,303	3.2	$19.97	1,303	$19.97
$21.00 to $21.86	1,415	6.0	$21.40	1,415	$21.40
$22.33 to $24.49	1,787	3.9	$22.82	1,321	$22.99
$24.61 to $26.85	1,787	4.8	$26.26	905	$25.70
$30.09 to $36.67	1,075	6.2	$30.21	9	$30.09
	8,714	4.8	$22.67	6,300	$20.83

At December 31, 2005, an additional four million common shares have been reserved for future issuance under TransCanada's Stock Option Plan. In 2005, TransCanada issued 1,075,000 options to purchase common shares at an average price of $30.21 under the Company's Stock Option Plan and the weighted average fair value of each option was determined to be $2.37. The Company used the Black-Scholes model for these calculations with the weighted average assumptions being four years of expected life, 4.0 per cent interest rate, 15 per cent volatility and 3.3 per cent dividend yield. The amount expensed for stock options, with a corresponding increase in contributed surplus for the year ended December 31, 2005, was $3 million (2004 $3 million; 2003 $2 million).

Shareholder Rights Plan

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

NOTE 16 RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

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

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

Net Investment in Foreign Operations

At December 31, 2005 and 2004, the Company had net investments in self sustaining foreign operations with a U.S. dollar functional currency which created an exposure to changes in exchange rates. The Company uses U.S. dollar denominated debt and derivatives to hedge this exposure on an after-tax basis. The fair value for derivatives used to manage the exposure is shown in the table below.

		2005		2004	
Asset/(Liability) *December 31 (millions of dollars)*	Accounting Treatment	**Fair Value**	**Notional or Notional Principal Amount**	Fair Value	Notional or Notional Principal Amount
U.S. dollar cross-currency swaps (maturing 2006 to 2012)	Hedge	**119**	**U.S. 450**	95	U.S. 400
U.S. dollar forward foreign exchange contracts (maturing 2006)	Hedge	**5**	**U.S. 525**	(1)	U.S. 305
U.S. dollar options (maturing 2006)	Hedge		**U.S. 60**	1	U.S. 100

Reconciliation of Foreign Exchange Adjustment (Losses)/Gains

December 31 (millions of dollars)	2005	2004
Balance at January 1	**(71)**	(40)
Translation losses on foreign currency denominated net assets[1]	**(21)**	(39)
Gains on derivatives	**23**	52
Income taxes	**(21)**	(44)
Balance at December 31	**(90)**	(71)

(1) In 2005, includes gains of $80 million (2004 $101 million) related to foreign currency denominated debt designated as a hedge.

Foreign Exchange Gains/(Losses)

Foreign exchange gains included in Other Expenses/(Income) for the year ended December 31, 2005 are $19 million (2004 $6 million; 2003 nil).

Foreign Exchange and Interest Rate Management Activity

The Company manages the foreign exchange and interest rate risks related to its U.S. dollar denominated debt, and transactions and interest rate exposures of the Canadian Mainline, the Alberta System and the BC System through the use of foreign currency and interest rate

derivatives. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms. The details of the foreign exchange and interest rate derivatives are shown in the table below.

		2005		2004	
Asset/(Liability) *December 31 (millions of dollars)*	Accounting Treatment	**Fair Value**	**Notional or Notional Principal Amount**	Fair Value	Notional or Notional Principal Amount
Foreign Exchange					
Cross- currency swaps					
(maturing 2010 to 2013)	Non-hedge	**(86)**	**363/U.S. 257**	(69)	363/U.S. 257
Interest Rate					
Interest rate swaps					
Canadian dollars					
(maturing 2007 to 2008)	Hedge	**4**	**100**	7	145
(maturing 2006 to 2009)	Non-hedge	**7**	**374**	9	374
		11		16	
U.S. dollars					
(maturing 2007 to 2009)	Non-hedge	**5**	**U.S. 100**	7	U.S. 100

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

		2005		2004	
Asset/(Liability) *December 31 (millions of dollars)*	Accounting Treatment	**Fair Value**	**Notional or Notional Principal Amount**	Fair Value	Notional or Notional Principal Amount
Foreign Exchange					
Options (maturing 2006)	Non-hedge	**1**	**U.S. 195**	2	U.S. 255
Forward foreign exchange contracts					
(maturing 2006)	Hedge	**2**	**U.S. 29**		
(maturing 2006)	Non-hedge	**1**	**U.S. 208**	1	U.S. 129
Interest Rate					
Options	Non-hedge				U.S. 50
Interest rate swaps					
Canadian dollar					
(maturing 2007 to 2009)	Hedge	**1**	**100**	4	100
(maturing 2006 to 2011)	Non-hedge	**1**	**423**	5	485
		2		9	
U.S. dollar					
(maturing 2013)	Hedge		**U.S. 50**	3	U.S. 375
(maturing 2006 to 2010)	Non-hedge	**18**	**U.S. 550**	22	U.S. 500
		18		25	

Certain of the Company's joint ventures use interest rate derivatives to manage interest rate exposures. The Company's proportionate share of the fair value of these outstanding derivatives at December 31, 2005 was nil (2004 $1 million).

Energy Price Risk Management

The Company executes power, natural gas and heat rate derivatives for overall management of its asset portfolio. Heat rate contracts are contracts for the sale or purchase of power that are priced based on a natural gas index. The fair value and notional volumes of contracts for differences and the swap, future, option and heat rate contracts are shown in the tables below.

Power

		2005	2004
Asset/(Liability)			
December 31 (millions of dollars)	Accounting Treatment	**Fair Value**	Fair Value
Power swaps and contracts for differences			
(maturing 2006 to 2011)	Hedge	**(130)**	7
(maturing 2006 to 2010)	Non-hedge	**13**	(2)
Gas swaps, futures and options			
(maturing 2006 to 2016)	Hedge	**17**	(39)
(maturing 2006 to 2008)	Non-hedge	**(11)**	(2)
Heat rate contracts			
(maturing 2006)	Non-hedge		(1)

		Power (GWh)[1]		**Gas (Bcf)[1]**	
Notional Volumes *December 31, 2005*	**Accounting Treatment**	**Purchases**	**Sales**	**Purchases**	**Sales**
Power swaps and contracts for differences					
(maturing 2006 to 2011)	**Hedge**	**2,566**	**7,780**		
(maturing 2006 to 2010)	**Non-hedge**	**1,332**	**456**		
Gas swaps, futures and options					
(maturing 2006 to 2016)	**Hedge**			**91**	**69**
(maturing 2006 to 2008)	**Non-hedge**			**15**	**18**
Heat rate contracts					
(maturing 2006)	**Non-hedge**		**35**		
December 31, 2004					
Power swaps and contracts for differences	Hedge	3,314	7,029		
	Non-hedge	438			
Gas swaps, futures and options	Hedge			80	84
	Non-hedge			5	8
Heat rate contracts	Non-hedge		229	2	

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

Certain of the Company's joint ventures use power derivatives to manage energy price risk exposures. The Company's proportionate share of the fair value of these outstanding power sales derivatives at December 31, 2005 was $(38) million (2004 nil) and relates to contracts which cover the period 2006 to 2008. The Company's proportionate share of the notional sales volumes associated with this exposure at December 31, 2005 was 2,058 GWh (2004 nil).

Fair Value of Financial Instruments

The fair value of cash and short-term investments and notes payable approximates their carrying amounts due to the short period to maturity. The fair value of long-term debt, long-term debt of joint ventures and preferred securities is determined using market prices for the same or similar issues.

	2005		2004	
December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Long-Term Debt				
Canadian Mainline	**4,233**	**5,327**	4,445	5,473
Alberta System	**2,258**	**2,858**	2,105	2,668
GTN	**466**	**470**	632	627
Foothills System	**400**	**415**	400	413
Portland	**281**	**292**	308	328
Other	**2,395**	**2,486**	2,633	2,731
Long-Term Debt of Joint Ventures	**978**	**1,101**	893	1,003
Preferred Securities	**536**	**554**	554	572

The fair value is provided solely for information purposes and is not recorded in the consolidated balance sheet.

Credit Risk

Credit risk results from the possibility that a counterparty to a derivative in which the Company has an unrealized gain fails to perform according to the terms of the contract. Credit exposure is minimized through the use of established credit management techniques, including formal assessment processes, contractual and collateral requirements, master netting arrangements and credit exposure limits. At December 31, 2005, for foreign currency and interest rate derivatives, total credit risk and the largest credit exposure to a single counterparty were $127 million and $44 million, respectively. At December 31, 2005, for power, natural gas and heat rate derivatives, total credit risk and the largest credit exposure to a single counterparty were $63 million and $39 million, respectively.

NOTE 17 INCOME TAXES

Provision for Income Taxes

Year ended December 31 (millions of dollars)	**2005**	2004	2003
Current			
Canada	**499**	373	243
Foreign	**51**	41	41
	550	414	284
Future			
Canada	**(46)**	34	183
Foreign	**106**	43	47
	60	77	230
	610	491	514

Geographic Components of Income

Year ended December 31 (millions of dollars)	**2005**	2004	2003

Canada	**1,316**	1,207	1,058
Foreign	**587**	342	324
Income from continuing operations before income taxes and non-controlling interests	**1,903**	1,549	1,382

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Reconciliation of Income Tax Expense

Year ended December 31 (millions of dollars)	**2005**	2004	2003
Income from continuing operations before income taxes and non-controlling interests	**1,903**	1,549	1,382
Federal and provincial statutory tax rate	**33.6%**	33.9%	36.7%
Expected income tax expense	**639**	525	507
Income tax differential related to regulated operations	**71**	62	29
Higher/(lower) effective foreign tax rates	**2**	2	(2)
Large corporations tax	**15**	21	28
Lower effective tax rate on equity in earnings of affiliates	**(29)**	(25)	(27)
Non-taxable portion of gains on sale of assets	**(68)**	(66)	
Change in valuation allowance		(7)	(3)
Other	**(20)**	(21)	(18)
Actual income tax expense	**610**	491	514

Future Income Tax Assets and Liabilities

December 31 (millions of dollars)	**2005**	2004
Deferred costs	**119**	71
Deferred revenue	**11**	18
Alternative minimum tax credits		10
Net operating and capital loss carryforwards	**1**	7
Other	**43**	72
	174	178
Less: Valuation allowance	**14**	17
Future income tax assets, net of valuation allowance	**160**	161
Difference in accounting and tax bases of plant, equipment and PPAs	**637**	456
Investments in subsidiaries and partnerships	**131**	114
Unrealized foreign exchange gains on long-term debt	**68**	45
Other	**27**	55
Future income tax liabilities	**863**	670
Net future income tax liabilities	**703**	509

Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments which the Company does not intend to repatriate in the foreseeable future. If provision for these taxes had been made, future income tax liabilities would increase by approximately $61 million at December 31, 2005 (2004 $57 million).

Income Tax Payments

Income tax payments of $531 million were made during the year ended December 31, 2005 (2004 $419 million; 2003 $220 million).

NOTE 18 NOTES PAYABLE

	2005		2004	
	Outstanding December 31[1]	Weighted Average Interest Rate Per Annum at December 31	Outstanding December 31[1]	Weighted Average Interest Rate Per Annum at December 31
Canadian dollars	765	3.4%	546	2.6%
U.S. dollars (2005 US$169)	197	4.5%		
	962		546	

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

Notes payable consists of commercial paper and line of credit drawings. At December 31, 2005, total credit facilities of $2.0 billion were available to support the Company's commercial paper programs and for general corporate purposes. Of this total, $1.5 billion was a committed five-year term syndicated credit facility. This facility is extendible on an annual basis and is revolving. In December 2005, the facility was extended to December 2010. The remaining amounts are either demand or non-extendible facilities.

At December 31, 2005, the Company had used approximately $271 million of its total lines of credit for letters of credit and to support its ongoing commercial arrangements. If drawn, interest on the lines of credit is charged at prime rates of Canadian chartered and U.S. banks and at other negotiated financial bases. The cost to maintain the unused portion of the lines of credit was $2 million for the year ended December 31, 2005 (2004 $2 million).

NOTE 19 ASSET RETIREMENT OBLIGATIONS

At December 31, 2005, the estimated undiscounted cash flows required to settle the asset retirement obligations with respect to Gas Transmission were $46 million (2004 $48 million), calculated using an inflation rate ranging from two to three per cent per annum. The estimated fair value of this liability was $12 million (2004 $12 million) after discounting the estimated cash flows at rates ranging from 5.5 per cent to 6.6 per cent. At December 31, 2005, the expected timing of payment for settlement of the obligations ranges from 12 to 24 years. No amount has been recorded for asset retirement obligations relating to the regulated natural gas transmission operation assets as it is not possible to make a reasonable estimate of the fair value of the liability due to the inability to determine the scope and timing of the asset retirements. Management believes it is reasonable to assume that all retirement costs associated with the regulated pipelines will be recovered through tolls in future periods.

At December 31, 2005, the estimated undiscounted cash flows required to settle the asset retirement obligations with respect to the Power business were $95 million (2004 $128 million), calculated using an inflation rate ranging from two to three per cent per annum. The estimated fair value of this liability was $21 million (2004 $24 million) after discounting the estimated cash flows at rates ranging from 5.5 per cent to 6.6 per cent. At December 31, 2005, the expected timing of payment for settlement of the obligations ranges from 13 to 28 years.

For the hydroelectric power plant assets, as it is not possible to make a reasonable estimate of the fair value of the liability due to the inability to determine the scope and timing of the asset retirements, no amount has been recorded for asset retirement obligations. For the Bruce Power nuclear assets, as the lessor is responsible for decommissioning liabilities under the lease agreement, no amount has been recorded for asset retirement obligations.

Reconciliation of Asset Retirement Obligations

(millions of dollars)	Gas Transmission	Power	Total
Balance at January 1, 2003	2	6	8
Revisions in estimated cash flows		1	1
Balance at December 31, 2003	2	7	9
New obligations and revisions in estimated cash flows	9	21	30
Removal of Power LP redemption obligations		(5)	(5)
Accretion expense	1	1	2
Balance at December 31, 2004	12	24	36
Revisions in estimated cash flows and lives	**(1)**	**1**	
Sale of Power LP		**(5)**	**(5)**
Accretion expense	**1**	**1**	**2**
Balance at December 31, 2005	**12**	**21**	**33**

NOTE 20 EMPLOYEE FUTURE BENEFITS

The Company sponsors DB Plans that cover substantially all employees. Benefits provided under the DB Plans are based on years of service and highest average earnings over three consecutive years of employment, and increase annually by a portion of the increase in the Consumer Products Index (CPI). Past service costs are amortized over the expected average remaining service life of employees, which is approximately 11 years.

The Company also provides its employees with post-employment benefits other than pensions, including termination benefits and defined life insurance and medical benefits beyond those provided by government-sponsored plans. Past service costs are amortized over the expected average remaining life expectancy of former employees, which at December 31, 2005 was approximately 12 years.

In 2005, the Company expensed $2 million (2004 $1 million; 2003 $1 million) related to retirement savings plans for its U.S. employees.

Total cash payments for employee future benefits for 2005, consisting of cash contributed by the Company to the DB Plans and other benefit plans was $74 million (2004 $89 million).

The Company measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuation of the pension plans for funding purposes was as of January 1, 2006, and the next required valuation is as of January 1, 2007.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2005**	2004	**2005**	2004
Change in Benefit Obligation				
Benefit obligation beginning of year	**1,100**	960	**123**	106
Current service cost	**32**	28	**3**	3
Interest cost	**63**	58	**7**	7
Employee contributions	**3**	2		
Benefits paid	**(60)**	(66)	**(6)**	(4)
Actuarial loss/(gain)	**149**	46	**21**	(12)
Foreign exchange rate changes	**(3)**			
Curtailment	**(2)**			
Acquisition		72		23
Benefit obligation end of year	**1,282**	1,100	**148**	123
Change in Plan Assets				
Plan assets at fair value beginning of year	**970**	799	**26**	
Actual return on plan assets	**119**	97	**2**	1
Employer contributions	**67**	84	**5**	4
Employee contributions	**3**	2		
Benefits paid	**(60)**	(66)	**(6)**	(4)
Foreign exchange rate changes	**(3)**			
Acquisition		54		25
Plan assets at fair value end of year	**1,096**	970	**27**	26
Funded status plan deficit	**(186)**	(130)	**(121)**	(97)
Unamortized net actuarial loss	**331**	255	**45**	25
Unamortized past service costs	**36**	39	**8**	7
Accrued benefit asset/(liability), net of valuation allowance	**181**	164	**(68)**	(65)

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

	Pension Benefit Plans		Other Benefit Plans	
	2005	2004	**2005**	2004
Other assets	**268**	224	**4**	3

Accounts payable	**(70)**	(42)	**(7)**	(5)
Deferred amounts	**(17)**	(18)	**(65)**	(63)
Total	**181**	164	**(68)**	(65)

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

	Pension Benefit Plans		Other Benefit Plans	
	2005	2004	**2005**	2004
Accrued benefit obligation	**(1,263)**	(1,084)	**(124)**	(100)
Fair value of plan assets	**1,075**	952		
Funded status plan deficit	**(188)**	(132)	**(124)**	(100)

The Company's expected contributions for the year ended December 31, 2006 are approximately $95 million for the pension benefit plans and approximately $7 million for the other benefit plans.

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

(millions of dollars)	Pension Benefits	Other Benefits
2006	58	6
2007	59	7
2008	62	7
2009	64	8
2010	67	8
Years 2011 to 2015	378	44

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

	Pension Benefit Plans		Other Benefit Plans	
	2005	2004	**2005**	2004
Discount rate	**5.00%**	5.75%	**5.15%**	6.00%
Rate of compensation increase	**3.50%**	3.50%		

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

	Pension Benefit Plans			Other Benefit Plans		
	2005	2004	2003	**2005**	2004	2003
Discount rate	**5.75%**	6.00%	6.25%	**6.00%**	6.25%	6.50%
Expected long-term rate of return on plan assets	**6.90%**	6.90%	7.25%	**7.20%**		
Rate of compensation increase	**3.50%**	3.50%	3.75%			

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for both the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and future expectations of the level and volatility of returns. Asset class benchmark returns, asset mix and anticipated benefit payments from plan assets are also considered in the determination of the overall expected rate of return. The discount rate is based on market interest rates of high quality bonds that match the timing and benefits expected to be paid under each plan.

For measurement purposes, a 9.0 per cent annual rate of increase in the per capita cost of covered health care benefits was assumed for 2006. The rate was assumed to decrease gradually to 5.0 per cent for 2015 and remain at that level thereafter. A one percentage point increase or decrease in assumed health care cost trend rates would have the following effects.

(millions of dollars)	Increase	Decrease
Effect on total of service and interest cost components	2	(1)

Effect on post-employment benefit obligation	18	(16)

The Company's net benefit cost is as follows.

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31 (millions of dollars)	**2005**	2004	2003	**2005**	2004	2003
Current service cost	**32**	28	25	**3**	3	2
Interest cost	**63**	58	52	**7**	7	6
Actual return on plan assets	**(119)**	(97)	(89)	**(2)**	(1)	
Actuarial loss/(gain)	**149**	46	66	**21**	(12)	7
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**125**	35	54	**29**	(3)	15
Difference between expected and actual return on plan assets	**54**	39	38		1	
Difference between actuarial loss recognized and actual actuarial loss on accrued benefit obligation	**(131)**	(32)	(58)	**(20)**	13	(6)
Difference between amortization of past service costs and actual plan amendments	**3**	3	3	**1**		1
Amortization of transitional obligation related to regulated business				**2**	2	2
Net benefit cost recognized	**51**	45	37	**12**	13	12

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

	Percentage of Plan Assets		**Target Allocation**
Asset Category	**2005**	2004	**2005**
Debt securities	**43%**	44%	**35% to 60%**
Equity securities	**57%**	56%	**40% to 65%**
	100%	100%	

Debt securities include the Company's long-term debt in the amount of $3 million (0.3 per cent of total plan assets) at December 31, 2005 and 2004. Equity securities include the Company's common shares in the amounts of $5 million (0.5 per cent of total plan assets) and $3 million (0.3 per cent of total plan assets) at December 31, 2005 and 2004, respectively.

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

Employee Future Benefits of Joint Ventures

Certain of the Company's joint ventures sponsor DB Plans, as well as post-employment benefits other than pensions, including defined life insurance and medical benefits beyond those provided by government-sponsored plans. The obligations of these plans are non-recourse to TransCanada. The amounts that follow represent TransCanada's proportionate share with respect to these plans.

Total cash payments for employee future benefits for 2005, consisting of cash contributed by the Company's joint ventures to DB Plans and other benefit plans was $4 million (2004 $1 million).

The Company's joint ventures measure the accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuation of the pension plans for funding purposes was as of January 1, 2006, and the next required valuation will be as of January 1, 2007.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2005**	2004	**2005**	2004
Change in Benefit Obligation				
Benefit obligation beginning of year	**45**	47	**2**	2
Current service cost	**4**	1	**1**	
Interest cost	**7**	3	**1**	
Employee contributions				
Benefits paid	**(3)**	(3)		
Actuarial loss	**17**		**2**	
Foreign exchange rate changes	**(1)**	(3)		
Bruce B[1]	**610**		**75**	
Benefit obligation end of year	**679**	45	**81**	2
Change in Plan Assets				
Plan assets at fair value beginning of year	**57**	56		
Actual return on plan assets	**18**	7		
Employer contributions	**4**	1		
Employee contributions				
Benefits paid	**(3)**	(3)		
Foreign exchange rate changes	**(1)**	(4)		
Bruce B[1]	**510**			
Plan assets at fair value end of year	**585**	57		
Funded status plan deficit	**(94)**	12	**(81)**	(2)
Unamortized net actuarial loss/(gain)	**125**	14	**(5)**	1
Unamortized past service costs	**1**			
Accrued benefit asset/(liability), net of valuation allowance	**32**	26	**(86)**	(1)

(1) The Company proportionately consolidated Bruce B, on a prospective basis at 31.6 per cent, effective October 31, 2005.

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

	Pension Benefit Plans		Other Benefit Plans	
	2005	2004	**2005**	2004
Other assets	**32**	26		
Deferred amounts			**(86)**	(1)
Total	**32**	26	**(86)**	(1)

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

	Pension Benefit Plans		Other Benefit Plans	
	2005	2004	**2005**	2004
Accrued benefit obligation	**(645)**	(5)	**(81)**	(2)
Fair value of plan assets	**534**	4		
Funded status plan deficit	**(111)**	(1)	**(81)**	(2)

The Company's joint ventures' expected contributions for the year ended December 31, 2006 are approximately $27 million for the pension benefit plans and approximately $2 million for the other benefit plans.

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

(millions of dollars)	Pension Benefits	Other Benefits
2006	11	2
2007	13	2
2008	16	2
2009	20	3
2010	24	3
Years 2011 to 2015	172	21

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

	Pension Benefit Plans		Other Benefit Plans	
	2005	2004	**2005**	2004
Discount rate	**5.30%**	5.75%	**5.15%**	5.75%
Rate of compensation increase	**3.50%**	4.00%		

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

	Pension Benefit Plans			Other Benefit Plans		
	2005	2004	2003	**2005**	2004	2003
Discount rate	**6.20%**	6.00%	6.75%	**6.25%**	6.00%	6.75%
Expected long-term rate of return on plan assets	**7.40%**	8.50%	8.80%			
Rate of compensation increase	**3.50%**	4.00%	4.00%			

A one percentage point increase or decrease in assumed health care cost trend rates would have the following effects.

(millions of dollars)	Increase	Decrease
Effect on total of service and interest cost components	1	(1)
Effect on post-employment benefit obligation	7	(6)

The Company's proportionate share of net benefit cost of joint ventures is as follows.

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31 (millions of dollars)	**2005**	2004	2003	**2005**	2004	2003
Current service cost	**4**	1	1	**1**		
Interest cost	**7**	3	3	**1**		
Actual return on plan assets	**(18)**	(7)	(7)			
Actuarial loss	**17**		4	**2**		
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**10**	(3)	1	**4**		
Difference between expected and actual return on plan assets	**9**	2	2			
Difference between actuarial loss recognized and actual actuarial loss on accrued benefit obligation	**(16)**	1	(4)	**(3)**		
Difference between amortization of past service costs and actual plan amendments						
Net benefit cost recognized by joint ventures	**3**		(1)	**1**		

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

	Percentage of Plan Assets		**Target Allocation**
Asset Category	**2005**	2004	**2005**
Debt securities	**30%**	38%	**30% to 40%**
Equity securities	**70%**	62%	**60% to 70%**
	100%	100%	

Debt securities include the Company's long-term debt in the amount of $1 million (0.2 per cent of total plan assets) and nil at December 31, 2005 and 2004, respectively. Equity securities include the Company's common shares in the amounts of $5 million (0.9 per cent of total plan assets) and nil at December 31, 2005 and 2004, respectively.

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

NOTE 21 CHANGES IN OPERATING WORKING CAPITAL

Year ended December 31 (millions of dollars)	**2005**	2004	2003
(Increase)/decrease in accounts receivable	**(100)**	16	98
(Increase)/decrease in inventories	**(50)**		15
(Increase)/decrease in other current assets	**(1)**	24	28
Increase/(decrease) in accounts payable	**97**	(4)	(46)
Increase/(decrease) in accrued interest	**5**	(7)	(2)
	(49)	29	93

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS **111**

NOTE 22 COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

Operating leases

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

Year ended December 31 (millions of dollars)	Minimum Lease Payments	Amounts Recoverable under Sub-Leases	Net Payments
2006	46	(12)	34
2007	52	(12)	40
2008	54	(12)	42
2009	54	(11)	43
2010	53	(11)	42

The operating lease agreements for premises, services and equipment expire at various dates through 2011, with an option to renew certain lease agreements for five years. The operating lease agreement for the natural gas storage facility expires in 2030 with lessee termination rights every fifth anniversary commencing in 2010 and with the lessor having the right to terminate the agreement every five years commencing in 2015. Net rental expense on operating leases for the year ended December 31, 2005 was $17 million (2004 $7 million; 2003 $2 million).

Bruce Power

TransCanada's share of Bruce A's signed commitments to third party suppliers for the next five years for the restart and refurbishment of the currently idle Units 1 and 2, extending the operating life of Unit 3 by replacing its steam generators and fuel channels when required and replacing the steam generators on Unit 4, is as follows.

Year ended December 31 (millions of dollars)	
2006	322
2007	311
2008	142
2009	69
2010	
	844

Aboriginal Pipeline Group

On June 18, 2003, the Mackenzie Delta gas producers, the APG and TransCanada reached an agreement which governs TransCanada's role in the Mackenzie Gas Pipeline Project. The project would result in a natural gas pipeline being constructed from Inuvik, Northwest Territories, to the northern border of Alberta, where it would connect with the Alberta System. Under the agreement, TransCanada agreed to finance the APG for its one-third share of project development costs. These costs were originally estimated to be approximately $90 million, but given extended project delays, the protracted regulatory process and the projected timing to reach a decision to construct the pipeline, this share is currently forecasted to increase to approximately $145 million. As at December 31, 2005, TransCanada had funded $87 million (2004 $60 million) of this loan which is included in other assets. The ability to recover this investment is dependent upon the outcome of the project.

Contingencies

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

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

Guarantees

The Company, together with Cameco Corporation and BPC Generation Infrastructure Trust (BPC), has severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, operator licenses, the lease agreement and contractor services. The terms of the guarantees range from 2007 to 2018.

As part of the reorganization of Bruce Power, including the formation of Bruce A and the commitment to restart and refurbish the Bruce A units, the Company, together with BPC, severally guaranteed one-half of certain contingent financial obligations of Bruce A related to the refurbishment agreement with the Ontario Power Authority and cost sharing and sublease agreements with Bruce B. The terms of the guarantees currently range from 2018 to 2019.

TransCanada's share of the exposure under these Bruce Power guarantees at December 31, 2005 was estimated to be approximately $652 million of a calculated maximum of $758 million. The current carrying amount of the liability related to these guarantees is nil and the fair value is approximately $17 million.

TransCanada has guaranteed the equity undertaking of a subsidiary which supports the payment, under certain conditions, of principal and interest on US$133 million of public debt obligations of TransGas. The Company has a 46.5 per cent interest in TransGas. Under the terms of the agreement, the Company severally with another major multinational company may be required to fund more than their proportionate share of debt obligations of TransGas in the event that the minority shareholders fail to contribute. Any payments made by TransCanada under this agreement convert into share capital of TransGas. The potential exposure is contingent on the impact of any change of law on TransGas' ability to service the debt. From the issuance of the debt in 1995 to date, there has been no change in applicable law and thus no exposure to TransCanada. The debt matures in 2010. The Company has made no provision related to this guarantee.

In connection with the acquisition of GTN, US$241 million of the purchase price was deposited into an escrow account. As at December 31, 2005, there was US$54 million remaining in the escrow account. The outstanding funds in the escrow account represent the full face amount of the potential liability under certain GTN guarantees and are to be used to satisfy the liability of GTN under these designated guarantees.

NOTE 23 DISCONTINUED OPERATIONS

The Board of Directors approved plans in previous years to dispose of the Company's International, Canadian Midstream, Gas Marketing and certain other businesses. Net income from discontinued operations for the year ended December 31, 2005 was nil (2004 $52 million, net of $27 million of income taxes; 2003 $50 million, net of $29 million of income taxes). Included in accounts payable at December 31, 2005 was the remaining $51 million provision for loss on discontinued operations (2004 $55 million).

SUPPLEMENTARY INFORMATION

QUARTERLY AND ANNUAL SHARE TRADING INFORMATION

Toronto Stock Exchange *(Stock trading symbol TRP)*	First	Second	Third	Fourth	Annual
2005 (dollars)					
High	**30.84**	**33.03**	**37.29**	**37.90**	**37.90**
Low	**28.94**	**29.23**	**31.49**	**34.06**	**28.94**
Close	**29.82**	**32.24**	**35.50**	**36.65**	**36.65**
Volume (millions of shares)	**64.1**	**54.1**	**61.4**	**58.4**	**238.0**
2004 (dollars)					
High	29.72	29.40	28.60	30.35	30.35
Low	26.45	25.70	25.37	26.98	25.37
Close	28.28	26.40	27.65	29.80	29.80
Volume (millions of shares)	90.4	70.1	62.8	56.8	280.1
2003 (dollars)					
High	23.00	25.67	25.80	28.49	28.49
Low	20.77	21.60	23.60	24.76	20.77
Close	21.55	23.75	25.07	27.88	27.88
Volume (millions of shares)	69.6	76.9	64.2	67.2	277.9

New York Stock Exchange *(Stock trading symbol TRP)*					
2005 (U.S. dollars)					
High	**25.49**	**26.85**	**31.61**	**32.41**	**32.41**
Low	**23.66**	**23.36**	**25.84**	**28.81**	**23.36**
Close	**24.70**	**26.46**	**30.55**	**31.48**	**31.48**
Volume (millions of shares)	**4.9**	**3.9**	**14.7**	**8.1**	**31.6**
2004 (U.S. dollars)					
High	22.38	22.39	22.30	24.91	24.91
Low	19.70	18.75	19.40	21.80	18.75
Close	21.50	19.78	21.85	24.87	24.87
Volume (millions of shares)	12.3	9.9	5.5	5.3	33.0
2003 (U.S. dollars)					
High	15.12	19.10	18.82	21.88	21.88
Low	14.16	14.62	17.45	18.47	14.16
Close	14.74	17.57	18.58	21.51	21.51
Volume (millions of shares)	6.5	5.3	2.5	6.9	21.2

SIX-YEAR FINANCIAL HIGHLIGHTS

(millions of dollars except where indicated)	**2005**	2004	2003	2002	2001	2000
Income Statement						
Revenues	**6,124**	5,497	5,636	5,225	5,285	4,384
Net Income from continuing operations	**1,209**	980	801	747	686	628
Net income/(loss) by segment						
Gas Transmission	**684**	586	622	653	585	623
Power	**561**	396	220	146	168	85
Corporate	**(36)**	(2)	(41)	(52)	(67)	(80)
Continuing operations	**1,209**	980	801	747	686	628
Discontinued operations		52	50		(67)	61
Net income	**1,209**	1,032	851	747	619	689
Cash Flow Statement						
Funds generated from operations	**1,951**	1,703	1,822	1,843	1,625	1,484
(Increase)/decrease in operating working capital	**(49)**	29	93	92	(487)	437
Net cash provided by operations	**1,902**	1,732	1,915	1,935	1,138	1,921
Capital expenditures and acquisitions	**2,071**	2,046	965	851	1,082	1,144
Dividends on common shares	**586**	552	510	466	418	423
Balance Sheet						
Assets						
Plant, property and equipment						
Gas Transmission	**16,774**	17,385	16,122	16,158	16,562	16,937
Power	**3,237**	1,342	1,310	1,340	1,116	776
Corporate	**27**	37	50	64	66	111
Total assets	**24,113**	22,422	20,887	20,555	20,531	25,245
Capitalization						
Long-term debt	**9,640**	9,749	9,516	8,899	9,444	10,008
Long-term debt of joint ventures	**937**	808	741	1,193	1,262	1,280
Preferred securities	**536**	554	598	944	950	1,208
Non-controlling interests Preferred shares of subsidiary	**389**	389	389	389	389	389
Common shareholders' equity	**7,206**	6,565	6,091	5,747	5,426	5,211

Per Common Share Data (dollars)						
Net income Basic						
Continuing operations	**$2.49**	$2.02	$1.66	$1.56	$1.44	$1.32
Discontinued operations		0.11	0.10		(0.14)	0.13
	$2.49	$2.13	$1.76	$1.56	$1.30	$1.45
Net income Diluted						
Continuing operations	**$2.47**	$2.01	$1.66	$1.55	$1.44	$1.32
Discontinued operations		0.11	0.10		(0.14)	0.13
	$2.47	$2.12	$1.76	$1.55	$1.30	$1.45
Dividends declared	**$1.22**	$1.16	$1.08	$1.00	$0.90	$0.80
Book Value[1][6]	**$14.79**	$13.54	$12.61	$11.99	$11.38	$10.97
Market Price						
Toronto Stock Exchange ($Cdn)						
High	**37.90**	30.35	28.49	23.91	21.13	17.25
Low	**28.94**	25.37	20.77	19.05	14.85	9.80
Close	**36.65**	29.80	27.88	22.92	19.87	17.20
Volume (millions of shares)	**238.0**	280.1	277.9	280.6	288.2	400.7
New York Stock Exchange ($US)						
High	**32.41**	24.91	21.88	15.56	13.41	11.50
Low	**23.36**	18.75	14.16	11.89	9.88	6.75
Close	**31.48**	24.87	21.51	14.51	12.51	11.50
Volume (millions of shares)	**31.6**	33.0	21.2	16.3	16.8	21.2
Shares outstanding (millions)						
Average for the year	**486.2**	484.1	481.5	478.3	475.8	474.6
End of year	**487.2**	484.9	483.2	479.5	476.6	474.9
Registered common shareholders[1]	**30,533**	31,837	33,133	34,902	36,350	30,758
Financial Ratios						
Return on average common shareholders' equity[2]	**17.6%**	16.3%	14.4%	13.4%	11.6%	13.6%
Dividend yield[3]	**3.3%**	3.9%	3.9%	4.4%	4.5%	4.7%
Price/earnings multiple[4][5]	**14.7**	14.0	15.8	14.7	15.3	11.9
Price/book multiple[4][6]	**2.5**	2.2	2.2	1.9	1.7	1.6
Debt to debt plus shareholders' equity[7]	**59%**	63%	64%	64%	67%	69%
Total shareholder return[8]	**28%**	11%	27%	21%	21%	48%
Earnings to fixed charges[9]	**2.9**	2.5	2.3	2.3	2.1	1.9

(1) As at December 31.

(2) The ratio of return on average common shareholders' equity is determined by dividing net income by average common shareholders' equity (i.e. opening plus closing shareholders' equity divided by 2) for each year.

(3) The ratio of dividend yield is determined by dividing dividends declared during the year by price per share as at December 31.

(4) Price per share refers to market price per share as reported on the Toronto Stock Exchange as at December 31.

(5) The price/earnings multiple is determined by dividing price per share by the basic net income per share.

(6) The price/book multiple is determined by dividing price per share by book value per share as calculated by dividing shareholders' equity by the number of shares outstanding as at December 31.

(7) Debt includes total long-term debt plus preferred securities as at December 31 and excludes long-term debt debt of joint ventures. Shareholders' equity in this ratio is at December 31.

(8)

Total shareholder return is the sum of the change in price per share plus the dividends received plus the impact of dividend re-investment in a calendar year, expressed as a percentage of the value of shares at the end of the previous year.

(9) The ratio of earnings to fixed charges is determined by dividing the income from continuing operations before financial charges and income taxes, excluding undistributed income from equity investees, by the financial charges incurred by the company (including capitalized interest).

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INVESTOR INFORMATION

STOCK EXCHANGES, SECURITIES AND SYMBOLS

TransCanada Corporation

Common shares are listed on the Toronto and New York stock exchanges under the symbol: TRP

TransCanada PipeLines Limited (TCPL)*

Preferred shares are listed on the Toronto Stock Exchange under the following symbols:

Cumulative redeemable first preferred Series U: TCA.PR.X and Series Y: TCA.PR.Y

8.25% Preferred Securities are listed on the New York Stock Exchange under the symbol: TCAPr

16.50% First Mortgage Pipe Line Bonds due 2007 are listed on the London Stock Exchange

* TransCanada PipeLines Limited (TCPL) is a wholly-owned subsidiary of TransCanada Corporation.

Annual Meeting The annual meeting of shareholders is scheduled for April 28, 2006 at 10:30 a.m. (Mountain Daylight Time) at the Roundup Centre, Calgary, Alberta.

Dividend Payment Dates Scheduled common share dividend payment dates in 2006 are January 31, April 28, July 31 and October 31.

Dividend Reinvestment and Share Purchase Plan TransCanada's dividend reinvestment and share purchase plan (Plan) allows common shareholders of TransCanada and preferred shareholders of TCPL to purchase additional common shares by reinvesting their cash dividends without incurring brokerage or administrative fees. Participants in the Plan may also buy additional common shares, up to $10,000 (US$7,000) per quarter. Please contact our Plan agent, Computershare Trust Company of Canada, for more information on the Plan or visit us at www.transcanada.com.

TRANSFER AGENTS, REGISTRARS AND TRUSTEE

TransCanada Corporation Common Shares Computershare Trust Company of Canada (Montreal, Toronto, Calgary and Vancouver) and Computershare Trust Company (New York)

TCPL Preferred Shares Computershare Trust Company of Canada (Montreal, Toronto, Calgary and Vancouver)

TCPL Preferred Securities The Bank of New York (New York)

TCPL First Mortgage Pipe Line Bonds CIBC Mellon Trust Company, as agent for National Trust Company (Toronto).

Co-Registrar and Paying Agent U.K. Series, 16.50%: Computershare Services PLC (London, England)

TCPL Debentures

Canadian Series: CIBC Mellon Trust Company (Halifax, Montreal, Toronto, Calgary and Vancouver)

11.10% series N	10.50% series O	10.50% series P	10.625% series Q	
11.85% series R	11.90% series S	11.80% series U	9.80% series V	9.45% series W

U.S. Series: The Bank of New York (New York) 9.875% and 8.625%

TCPL Subordinated Debentures The Bank of Nova Scotia Trust Company of New York (New York) U.S. Series 9.125%

TCPL Canadian Medium Term Notes CIBC Mellon Trust Company (Halifax, Montreal, Toronto, Calgary and Vancouver)

TCPL U.S. Medium Term Notes (unsubordinated notes) and Senior Notes The Bank of New York (New York)

NGTL Debentures

Canadian Series: CIBC Mellon Trust Company (Halifax, Montreal, Toronto, Calgary and Vancouver)

11.95% series 13	11.70% series 15	11.20% series 18	12.625% series 19
12.20% series 20	12.20% series 21	9.90% series 23	

U.S. Series: U.S. Bank Trust National Association (New York) 8.50% and 7.875%

NGTL Canadian Medium Term Notes CIBC Mellon Trust Company (Halifax, Montreal, Toronto, Calgary and Vancouver)

NGTL U.S. Medium Term Notes U.S. Bank Trust National Association (New York)

REGULATORY FILINGS

Annual Information Form TransCanada's 2005 Annual Information Form, as filed with Canadian securities commissions and as filed under Form 40-F with the SEC, is available on our website at www.transcanada.com.

A printed copy may be obtained from:

Corporate Secretary, TransCanada Corporation, P.O. Box 1000, Station M, Calgary, Alberta, Canada T2P 4K5

SHAREHOLDER ASSISTANCE

If you are a registered shareholder and have questions regarding your account, please contact our transfer agent in writing, by telephone, fax or e-mail at:

Computershare Trust Company of Canada, 100 University Avenue, 9th Floor, Toronto, Ontario, Canada M5J 2Y1

Toll-free: 1 (800) 340-5024
Telephone: 1 (514) 982-7959
E-mail: transcanada@computershare.com
Fax: 1 (888) 453-0330 (North America)
Fax: 1 (416) 263-9394 (outside North America)

If you hold your shares in a brokerage account (beneficial shareholder), questions should be directed to your broker on all administrative matters.

If you would like to receive quarterly reports, please contact Computershare or visit our website at www.transcanada.com.

Electronic Proxy Voting and Delivery of Documents TransCanada is pleased to offer registered and beneficial shareholders the ability to receive their documents (annual report, management information circular, notice of meeting and view-only proxy form) and vote online.

In 2006, registered shareholders who opt to receive their documents electronically will have a tree planted on their behalf through eTree. For more information and to sign up online, registered shareholders can visit www.etree.ca/transcanada.

Shareholders who do not have access to e-mail, or who still prefer to receive their proxy materials by mail also have the ability to choose whether to receive TransCanada's annual report by regular mail. Each year, shareholders are required to renew their option and will receive a notification for doing so. The annual report is available on the TransCanada website at www.transcanada.com/investor/financial.html at the same time that the report is mailed to shareholders.

Electronic delivery and the ability to opt out of receiving the annual report by mail, provides increased convenience to shareholders, benefits to the environment and reduced mailing and printing costs for the company.

TransCanada in the Community TransCanada's annual Corporate Social Responsibility Report is available at www.transcanada.com. If you would like to receive a copy of this report by mail, please contact:

Communications P.O. Box 1000, Station M, Calgary, Alberta T2P 4K5, 1 (403) 920-2000 or 1 (800) 661-3805.

Visit our website at www.transcanada.com to access TransCanada's corporate and financial information, including quarterly reports, news releases, real-time conference call webcasts and investor presentations.

Si vous désirez vous procurer un exemplaire de ce rapport en français, veuillez consulter notre site web ou vous adresser par écrit à TransCanada Corporation, bureau du secrétaire.

BOARD OF DIRECTORS

S. Barry Jackson*
Chairman
TransCanada Corporation
Calgary, Alberta

Harold N. Kvisle
President and CEO
TransCanada Corporation
Calgary, Alberta

Douglas D. Baldwin[1][3]
Corporate Director
Calgary, Alberta

Kevin E. Benson[1]
President and CEO,
Laidlaw International, Inc.
Wheaton, Illinois

Derek H. Burney, O.C.[2]
Chairman of the Board
New Brunswick Power
Ottawa, Ontario

Wendy K. Dobson[2][4]
Professor, Rotman School
of Management and Director,
Institute for International Business
University of Toronto
Uxbridge, Ontario

E. Linn Draper[3][4]
Former Chairman, President and CEO
American Electric Power Co., Inc. (AEP)
Lampasas, Texas

The Hon. Paule Gauthier, P.C., O.C., O.Q., Q.C.[1][3]
Senior Partner
Desjardins Ducharme L.L.P.
Québec, Québec

Kerry L. Hawkins[3][4]
Retired President
Cargill Limited
Winnipeg, Manitoba

Paul L. Joskow[1][2]
Professor, Department of Economics
Massachusetts Institute of
Technology
Cambridge, Massachusetts

David P. O'Brien[2][4]
Chairman
EnCana Corporation
Royal Bank of Canada
Calgary, Alberta

Harry G. Schaefer, F.C.A.[1][2]
President
Schaefer & Associates Ltd.
and Vice-Chairman
TransCanada Corporation
Calgary, Alberta

* Non-voting member of all committees of the Board

(1) Member, Audit Committee

(2) Member, Governance Committee

(3) Member, Health, Safety and Environment Committee

(4) Member, Human Resources Committee

CORPORATE GOVERNANCE

Please refer to TransCanada's Notice of 2006 Annual Meeting of Common Shareholders and Management Proxy Circular for the company's statement of corporate governance.

TransCanada's Corporate Governance Guidelines, Board charter, Committee charters, and codes of business conduct and ethics are available on our website at www.transcanada.com. Also available on our website is a summary of the significant ways in which TransCanada's corporate governance practices differ from those required to be followed by U.S. domestic companies under the New York Stock Exchange's listing standards.

Additional information relating to the company is filed with securities regulators in Canada on SEDAR at www.sedar.com and in the United States on EDGAR at www.sec.gov. The documents referred to in this Annual Report may be obtained free of charge by contacting TransCanada's Corporate Secretary at P.O. Box 1000, Station M, Calgary, Alberta, Canada T2P 4K5, or by telephoning 1 (403) 920-2000.

Ethics Help-Line The Audit Committee of the Board of Directors has established an anonymous and confidential toll-free telephone number for employees, contractors and others to call with respect to accounting irregularities and ethical violations. The Ethics Help-Line number is 1 (888) 920-2042.

TRANSCANADA CORPORATION
RECONCILIATION TO UNITED STATES GAAP

AUDITORS' REPORT ON RECONCILIATION TO UNITED STATES GAAP

To the Shareholders of TransCanada Corporation

On February 27, 2006, we reported on the consolidated balance sheets of TransCanada Corporation as at December 31, 2005 and 2004 and the consolidated statements of income, retained earnings and cash flows for each of the years in the three-year period ended December 31, 2005, which are included in the annual report on Form 40-F. In connection with our audits conducted in accordance with Canadian generally accepted auditing standards of the aforementioned consolidated financial statements, we also have audited the related supplemental note entitled "Reconciliation to United States GAAP" included in the Form 40-F. This supplemental note is the responsibility of the Company's management. Our responsibility is to express an opinion on this supplemental note based on our audits.

In our opinion, such supplemental note, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ KPMG LLP

Chartered Accountants
Calgary, Canada

February 27, 2006

TRANSCANADA CORPORATION
RECONCILIATION TO UNITED STATES GAAP

The 2005 audited consolidated financial statements of TransCanada Corporation (TransCanada or the Company) have been prepared in accordance with Canadian generally accepted accounting principles (GAAP), which in some respects, differ from U.S. GAAP. The effects of these differences on the Company's consolidated financial statements for the year ended December 31, 2005 are provided in the following U.S. GAAP condensed consolidated financial statements which should be read in conjunction with TransCanada's 2005 audited consolidated financial statements prepared in accordance with Canadian GAAP.

Condensed Statement of Consolidated Income and Comprehensive Income in Accordance with U.S. GAAP[1]

Year ended December 31 (millions of dollars except per share amounts)	2005	Restated[3] 2004	Restated[3] 2003
Revenues	**5,333**	5,014	5,121
Cost of sales	**840**	777	814
Other costs and expenses	**1,794**	1,618	1,645
Depreciation	**924**	857	819
	3,558	3,252	3,278
Operating income	**1,775**	1,762	1,843
Other (income)/expenses			
Equity income[1]	**(458)**	(402)	(380)
Other expenses[2][3][4]	**422**	872	917
Dilution gain[3]		(40)	
Income taxes	**607**	490	515
	571	920	1,052
Income from continuing operations U.S. GAAP	**1,204**	842	791
Net income from discontinued operations U.S. GAAP		52	50
Income before cumulative effect of the application of accounting changes in accordance with U.S. GAAP	**1,204**	894	841
Cumulative effect of the application of accounting changes, net of tax			(13)
Net Income in Accordance with U.S. GAAP	**1,204**	894	828
Adjustments affecting comprehensive income under U.S. GAAP			
Foreign currency translation adjustment, net of tax	**(18)**	(31)	(54)
Changes in minimum pension liability, net of tax[5]	**(51)**	72	(2)
Unrealized(loss)/gain on derivatives, net of tax[6]	**(54)**	1	8
Comprehensive Income in Accordance with U.S. GAAP	**1,081**	936	780
Net Income Per Share in Accordance with U.S. GAAP			
Continuing operations	**$ 2.48**	$ 1.74	$ 1.65
Discontinued operations		0.11	0.10
Income before cumulative effect of the application of accounting changes in accordance with U.S. GAAP	**$ 2.48**	$ 1.85	$ 1.75
Cumulative effect of the application of accounting changes, net of tax			(0.03)

Year ended December 31 (millions of dollars except per share amounts)	2005	Restated[3] 2004	Restated[3] 2003
Basic	**$ 2.48**	$ 1.85	$ 1.72
Diluted[7]	**$ 2.46**	$ 1.84	$ 1.71

Net Income Per Share in Accordance with Canadian GAAP			
Basic	**$ 2.49**	$ 2.13	$ 1.76
Diluted	**$ 2.47**	$ 2.12	$ 1.76
Dividends per common share	**$ 1.22**	$ 1.16	$ 1.08
Common Shares Outstanding (millions)			
Average for the period Basic	**486.2**	484.1	481.5
Average for the period Diluted	**489.1**	486.7	483.9

Reconciliation of Income from Continuing Operations

Year ended December 31 (millions of dollars)	2005	Restated[3] 2004	Restated[3] 2003
Net Income from Continuing Operations in Accordance with Canadian GAAP	**1,209**	980	801
U.S. GAAP adjustments			
Unrealized (loss)/gain on energy contracts[6]	**(14)**	10	28
Tax impact of unrealized (loss)/gain on energy contracts	**5**	(3)	(10)
Equity gain/(loss)[8][9]	**5**	(2)	(18)
Tax impact of equity gain/(loss)	**(1)**		6
Unrealized gain/(loss) on foreign exchange and interest rate derivatives[6]	**1**	(12)	(9)
Tax impact of gain/(loss) on foreign exchange and interest rate derivatives	**(1)**	4	3
Amortization of deferred gains related to Power LP[3][4]		(3)	(10)
Deferred gains related to Power LP[3][4]		(132)	
Income from Continuing Operations in Accordance with U.S. GAAP	**1,204**	842	791

Condensed Statement of Consolidated Cash Flows in Accordance with U.S. GAAP[1]

Year ended December 31 (millions of dollars)	2005	2004	2003
Cash Generated from Operations[10]			
Net cash provided by operating activities	**1,628**	1,620	1,759
Investing Activities			
Net cash used in investing activities	**(1,171)**	(1,367)	(946)
Financing Activities			
Net cash used in financing activities	**(514)**	(332)	(626)
Effect of Foreign Exchange Rate Changes on Cash and Short-Term Investments	**13**	(87)	(54)
(Decrease)/Increase in Cash and Short-Term Investments	**(44)**	(166)	133
Cash and Short-Term Investments			
Beginning of year	**127**	293	160
Cash and Short-Term Investments			
End of year	**83**	127	293

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

December 31 (millions of dollars)	2005	2004
Current assets[11]	**1,058**	911
Long-term investments[8][9]	**2,168**	2,163
Plant, property and equipment	**17,348**	17,083
Regulatory asset[12]	**2,601**	2,606
Other assets[8]	**2,028**	1,217
	25,203	23,980
Current liabilities[13]	**2,754**	2,581
Deferred amounts[6][9]	**1,298**	785
Long-term debt[6]	**9,675**	9,789
Deferred income taxes[12]	**3,102**	3,048
Preferred securities	**536**	554
Non-controlling interests	**783**	700
Shareholders' equity	**7,055**	6,523
	25,203	23,980

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

(millions of dollars)	Cumulative Translation Account	Minimum Pension Liability (SFAS No. 87)	Cash Flow Hedges (SFAS No. 133)	Total
Balance at January 1, 2003	14	(96)	(13)	(95)
Changes in minimum pension liability, net of tax of $1[5]		(2)		(2)
Unrealized gain on derivatives, net of tax of nil[6]			8	8
Foreign currency translation adjustment, net of tax of $(64)	(54)			(54)
Balance at December 31, 2003	(40)	(98)	(5)	(143)
Changes in minimum pension liability, net of tax of $(39)[5]		72		72
Unrealized gain on derivatives, net of tax of $(3)[6]			1	1
Foreign currency translation adjustment, net of tax of $(44)	(31)			(31)
Balance at December 31, 2004	(71)	(26)	(4)	(101)
Changes in minimum pension liability, net of tax of $27[5]		**(51)**		**(51)**
Unrealized loss on derivatives, net of tax of $28[6]			**(54)**	**(54)**
Foreign currency translation adjustment, net of tax of $(21)	**(18)**			**(18)**
Balance at December 31, 2005	**(89)**	**(77)**	**(58)**	**(224)**

(1) In accordance with U.S. GAAP, the Condensed Statement of Consolidated Income, Statement of Consolidated Cash Flows and Consolidated Balance Sheet of TransCanada are prepared using the equity method of accounting for joint ventures.

(2) Other expenses included an allowance for funds used during construction of $3 million for the year ended December 31, 2005 (2004 $3 million; 2003 $2 million).

(3)

The Company recorded its investment in TransCanada Power, L.P. (Power LP) using the proportionate consolidation method for Canadian GAAP purposes and as an equity investment for U.S. GAAP purposes. During the period from 1997 to April 2004, the Company was obligated to fund the redemption of Power LP units in 2017. As a result, under Canadian GAAP, TransCanada accounted for the issuance of units by Power LP to third parties as a sale of a future net revenue stream and the resulting gains were deferred and amortized to income over the period to 2017. The redemption obligation was removed in April 2004 and the unamortized gains were

recognized as income. Under U.S. GAAP, any such gains in the period from 1997 to April 2004 are characterized as dilution gains and, because the Company was committed to fund the redemption of the units, the gains are recorded, on an after-tax basis, as equity transactions in shareholders' equity.

The Company's accounting policy for dilution gains is to record them as income for both Canadian and U.S. GAAP purposes, however, U.S. GAAP requires such gains to be recorded directly in equity if there is a contemplation of reacquisition of units. With the removal of the redemption obligation in April 2004, subsequent issuances of units by Power LP are accounted for as dilution gains in income for both Canadian and U.S. GAAP purposes.

(4)

Correction of Error:

In the period 1997 to 2001, the Company recorded certain transactions involving Power LP as sales of a revenue stream for both Canadian and U.S. GAAP purposes. For U.S. GAAP purposes, these transactions should have been accounted for as dilution gains (see footnote 3 above). This was corrected on a retroactive basis. The impact on previously reported amounts for U.S. GAAP purposes is as follows:

(millions of dollars except per share amounts)	**2005**	**2004**	**2003**
Decrease in:			
Income from continuing operations		135	10
Net income		135	10
Net income per share in accordance with U.S. GAAP			
Continuing operations		$ 0.28	$ 0.02
Discontinued operations			
Basic		$ 0.28	$ 0.02
Diluted		$ 0.28	$ 0.02

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

(5)

Under U.S. GAAP, a net loss recognized pursuant to Statement of Financial Accounting Standards (SFAS) No. 87 "Employers' Accounting for Pensions" as an additional pension liability not yet recognized as net period pension cost, must be recorded as a component of comprehensive income. As a result of recording an additional pension liability, the amounts recognized in the Company's balance sheet at December 31 are as follows.

December 31 (millions of dollars)	**2005**	**2004**
Prepaid benefit cost	**6**	183
Regulatory asset	**107**	
Other assets	**37**	1
Accounts payable	**(70)**	(42)
Deferred amounts	**(17)**	(18)
Accumulated other comprehensive income	**118**	40
Net amount recognized	**181**	164

The accumulated benefit obligation for the Company's defined benefit pension plans was $1,123 million at December 31, 2005 (2004 $943 million).

(6)

All foreign exchange and interest rate derivatives are recorded in the Company's consolidated financial statements at fair value under Canadian GAAP. Under the provisions of SFAS No. 133 "Accounting for Derivatives and Hedging Activities", all derivatives are recognized as assets and liabilities on the balance sheet and measured at fair value. For derivatives designated as fair value hedges, changes in the fair value are recognized in earnings together with an equal or lesser amount of changes in the fair value of the hedged item attributable to the hedged risk. For derivatives designated as cash flow hedges, changes in the fair value of the derivative that are effective in offsetting the hedged risk are recognized in other comprehensive income until the hedged item is recognized in earnings. Any ineffective portion of the change in fair value is also recognized in earnings each period.

Substantially all of the amounts recorded in 2005, 2004 and 2003 as differences between U.S. and Canadian GAAP, for income from continuing operations, relate to the differences in accounting treatment with respect to the hedged item and, for comprehensive income, relate to cash flow hedges.

Substantially all of the amounts recorded in the twelve months ended December 31, 2005, 2004 and 2003 as differences between U.S. and Canadian GAAP in respect of energy contracts relate to gains and losses on derivative energy contracts for periods before they were documented as hedges for purposes of U.S. GAAP and to differences in accounting with respect to physical energy contracts.

During 2005, under the provisions of SFAS 133, net gains of $8 million (2004 $10 million; 2003 $47 million) from the hedges of changes in the fair value of long-term debt, and net losses of $8 million (2004 $18 million; 2003 $53 million) in the fair value of the

hedged item were included in earnings for U.S. GAAP purposes as an adjustment to interest expense and foreign exchange losses. No amounts of the derivatives' gains or losses were excluded from the assessment of hedge effectiveness in fair value hedging relationships.

No amounts were included in income in 2005, 2004, and 2003 with respect to ineffectiveness of cash flow hedges. For amounts included in other comprehensive income at December 31, 2005, $4 million (2004 $(4) million; 2003 $9 million) relates to the hedging of interest rate risk; $(1) million (2004 $3 million; 2003 $5 million) relates to the hedging of foreign exchange rate risk; and $(57) million (2004 $2 million; 2003 $(6) million) relates to the hedging of energy price risk. Of these amounts, $(44) million is expected to be recorded in earnings during 2006.

At December 31, 2005, assets of $175 million (2004 $29 million) and liabilities of $110 million (2004 $27 million) were reduced for U.S. GAAP purposes to reflect the fair value of derivatives and the corresponding change in the fair value of hedged items.

(7)

Diluted net income per share in accordance with U.S. GAAP for the year ended December 31, 2005 consists of continuing operations $2.46 per share (2004 $1.73 per share; 2003 $1.61 per share), and discontinued operations nil (2004 $0.11 per share; 2003 $0.10).

(8)

Under Canadian GAAP, pre-operating costs incurred during the commissioning phase of a new project are deferred until commercial production levels are achieved. After such time, those costs are amortized over the estimated life of the project. Under U.S. GAAP, such costs are expensed as incurred. Certain start-up costs incurred by Bruce Power L.P. (Bruce B), an equity investment, are required to be expensed under U.S. GAAP. Under both Canadian GAAP and U.S. GAAP, interest is capitalized on expenditures relating to construction of development projects actively being prepared for their intended use. In Bruce B, under U.S. GAAP, the carrying value of development projects against which interest is capitalized is lower due to the expensing of pre-operating costs.

(9)

Financial Interpretation (FIN) 45 requires the recognition of a liability for the fair value of certain guarantees that require payments contingent on specified types of future events. The measurement standards of FIN 45 are applicable to guarantees entered into after January 1, 2003. For U.S. GAAP purposes, the fair value of guarantees recorded as a liability at December 31, 2005 was $17 million (2004 $9 million) and relates to the Company's equity interest in Bruce B and Bruce Power A L.P. The net income impact with respect to the guarantees for the year ended December 31, 2005 was $1 million (2004 and 2003 nil).

(10)

In accordance with U.S. GAAP, all current taxes are included in cash generated from operations.

(11)

Current assets at December 31, 2005 include derivative contracts of $49 million (2004 $23 million) and hedging deferrals of $93 million (2004 $10 million).

(12)

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

(13)

Current liabilities at December 31, 2005 include dividends payable of $154 million (2004 $146 million) and current taxes payable of $251 million (2004 $260 million).

Income Taxes

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

December 31 (millions of dollars)	2005	2004
Deferred Tax Liabilities		
Difference in accounting and tax bases of plant, equipment and power purchase arrangements	**1,724**	1,741
Taxes on future revenue requirement	**874**	914
Investments in subsidiaries and partnerships	**555**	438
Other	**147**	140
	3,300	3,233
Deferred Tax Assets		
Net operating and capital loss carryforwards	**1**	7
Deferred amounts	**148**	89
Other	**63**	106
	212	202
Less: Valuation allowance	**14**	17
	198	185
Net deferred tax liabilities	**3,102**	3,048

Other

In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123 (revised 2004) "Share-Based Payment" which requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values. The pro forma disclosures previously permitted under SFAS No. 123 no longer will be an alternative to financial statement recognition. In 2002, TransCanada adopted accounting for its stock-based compensation plans using the fair value recognition provisions under Canadian GAAP. Therefore, adopting the provisions under SFAS No 123 (revised 2004) has no impact on the U.S. GAAP financial statements of the Company.

In March 2005, (FASB) issued a Staff Position (FSP) on a previously issued Financial Interpretation (FIN). The provisions of FSP FIN 46 (R)-5 "Implicit Variable Interests under revised FIN 46(R), Consolidation of Variable Interest Entities" require that a reporting enterprise consider consolidating implicit variable interests when applying the provisions of FIN 46(R). Adopting these provisions has had no impact on the U.S. GAAP financial statements of the Company.

In March 2005, FASB issued FIN 47 "Accounting for Conditional Asset Retirement Obligations an interpretation of FASB No. 143". FIN 47 clarifies that the term "conditional asset retirement obligation" as used in SFAS No. 143, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. It also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. Adopting the clarification under this interpretation has had no impact on the U.S. GAAP financial statements of the Company.

In May 2005, FASB issued SFAS No. 154 "Accounting Changes and Error Corrections a replacement of APB Opinion No. 20 and SFAS No. 3" which is effective for fiscal years beginning after December 15, 2005. SFAS No. 154 changes the requirements for the accounting for and reporting of a change in accounting principle and error correction. It establishes, unless impracticable, retrospective application as the required method for reporting a change in accounting principle in the absence of explicit transition requirements specific to the newly adopted accounting principle. Adopting the provisions under SFAS No. 154, as of January 1, 2006, is not expected to have an impact on the U.S. GAAP financial statements of the Company.

Summarized Financial Information of Long-Term Investments

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

Year ended December 31 (millions of dollars)	2005	2004	2003
Income			
Revenues	**1,233**	1,249	1,169
Other costs and expenses	**(508)**	(594)	(552)
Depreciation	**(173)**	(173)	(160)
Financial charges and other	**(94)**	(80)	(77)
Proportionate share of income before income taxes of long-term investments	**458**	402	380

December 31 (millions of dollars)	2005	2004
Balance Sheet		
Current assets	**456**	358
Plant, property and equipment	**3,365**	3,470
Current liabilities	**(319)**	(254)
Deferred amounts (net)	**(73)**	(199)
Non-recourse debt	**(1,236)**	(1,195)
Deferred income taxes	**(25)**	(17)
Proportionate share of net assets of long-term investments	**2,168**	2,163

The distributed earnings from long-term investments for the year ended December 31, 2005 were $371 million (2004 $258 million; 2003 $192 million).

Exhibit 99.1

COMMENTS BY AUDITORS FOR U.S. READERS ON CANADA-U.S. REPORTING DIFFERENCE

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Company's financial statements, such as the changes described in Note 2 Accounting Changes to the Company's consolidated financial statements as at December 31, 2005 and 2004, and for each of the years in the three-year period ended December 31, 2005 which are incorporated by reference herein. Our report to the shareholders dated February 27, 2006, which is incorporated by reference herein, is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

/s/ KPMG LLP

Chartered Accountants

Calgary, Canada
February 27, 2006

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