TRANSCANADA PIPELINES LTD
Form 40-F
February 26, 2010

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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, 2009** Commission File Number **1-8887**

TRANSCANADA PIPELINES LIMITED

(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)

TransCanada PipeLine USA Ltd., 717 Texas Street
Houston, Texas, 77002-2761; (832) 320-5201
(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: **None**
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, 2009, 4,000,000 Cumulative Redeemable First Preferred Shares, Series U
and 4,000,000 Cumulative Redeemable First Preferred Shares, Series Y
were issued and outstanding
All of the Registrant's common shares are owned by TransCanada Corporation**

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.
F-9	333-154961
F-9	333-163641

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

A. Audited Annual Financial Statements

For audited consolidated financial statements, including the report of the independent chartered accountants, see pages 89 through 142 of the TransCanada PipeLines Limited ("TCPL") 2009 Management's Discussion and Analysis and Audited Consolidated Financial Statements included herein. See the related supplementary note entitled "Reconciliation to United States GAAP" for a reconciliation of the differences between Canadian and United States generally accepted accounting principles, including the auditors' report, attached as document 13.4, and the related comments by auditors for United States readers on Canada United States reporting differences, attached as document 99.1.

B. Management's Discussion & Analysis

For management's discussion and analysis, see pages 2 through 88 of the TCPL 2009 Management's Discussion and Analysis and Audited Consolidated Financial Statements included herein.

For the purposes of this Report, only pages 2 through 88 and 89 through 142 of the TCPL 2009 Management's Discussion and Analysis and Audited Consolidated Financial Statements shall be deemed incorporated herein by reference and filed, and the balance of such 2009 Management's Discussion and Analysis and Audited Consolidated Financial Statements, except as otherwise specifically incorporated by reference in the TCPL Annual Information Form, shall be deemed not filed with the U.S. Securities and Exchange Commission (the "Commission") as part of this Report under the *Exchange Act*.

C. Management's Report on Internal Control Over Financial Reporting

For information on management's internal control over financial reporting, see:

i. "Report of Management" included in TCPL's Audited Consolidated Financial Statements on page 89;

ii. the section entitled "Management's Annual Report on Internal Control Over Financial Reporting" under the heading "Controls and Procedures" in Management's Discussion and Analysis on page 73 of the TCPL Management's Discussion and Analysis and Audited Consolidated Financial Statements; and

iii. Management's Report on Internal Control Over Financial Reporting attached as document 13.5.

UNDERTAKING

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the staff of the Commission, 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

For information on disclosure controls and procedures, see "Controls and Procedures" in Management's Discussion and Analysis on page 73 of the TCPL 2009 Management's Discussion and Analysis and Audited Consolidated Financial Statements.

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. Kevin E. Benson has been designated an 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 Commission has indicated that the designation of Mr. Benson as an audit committee financial expert does not make Mr. Benson an "expert" for any purpose, impose any duties, obligations or liability on Mr. Benson 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 President and Chief Executive Officer, Chief Financial Officer, Controller, directors, employees and contractors. The Registrant's codes are available on its website at www.transcanada.com. No waivers have been granted from any provision of the codes during the 2009 fiscal year.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

For information on principal accountant fees and services, see "Corporate Governance Audit Committee External Auditor Service Fees" and "Corporate Governance Audit Committee Pre-Approval Policies and Procedures" on page 27 of the TCPL Annual Information Form.

OFF-BALANCE SHEET ARRANGEMENTS

The Registrant has no off-balance sheet arrangements, as defined in this Form, other than the guarantees and commitments described in Note 24 of the Notes to the Audited Consolidated Financial Statements attached to this Form 40-F and incorporated herein by reference.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

For information on Tabular Disclosure of Contractual Obligations, see "Contractual Obligations" in Management's Discussion and Analysis on page 57 of the TCPL 2009 Management's Discussion and Analysis and Audited Consolidated Financial Statements.

IDENTIFICATION OF THE AUDIT COMMITTEE

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

Chair:	K.E. Benson
Members:	D.H. Burney
	E.L. Draper
	P.L. Joskow
	J.A. MacNaughton
	D.M.G. Stewart

FORWARD-LOOKING INFORMATION

This document, the documents incorporated by reference, and other reports and filings made with the securities regulatory authorities may contain certain information that is forward-looking and is subject to important risks and uncertainties. The words "anticipate", "expect", "believe", "may", "should", "estimate", "project", "outlook", "forecast" or other similar words are used to identify such forward looking information. Forward-looking statements in this document are intended to provide TCPL's securityholders and potential investors with information regarding TCPL and its subsidiaries, including management's assessment of TCPL's and its subsidiaries' future financial and operational plans and outlook. Forward-looking statements in this document may include, among others, statements regarding the anticipated business prospects and financial performance of TCPL and its subsidiaries, expectations or projections about the future, strategies and goals for growth and expansion, expected and future cash flows, costs, schedules, operating and financial results and expected impact of future commitments and contingent liabilities. All forward-looking statements reflect TCPL's beliefs and assumptions based on information available at the time the statements were made. Actual results or events may differ from those predicted in these forward-looking statements. Factors that could cause actual results or events to differ materially from current expectations include, among others, the ability of TCPL to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the operating performance of TCPL's pipeline and energy assets, the availability and price of energy commodities, capacity payments, regulatory processes and decisions, changes in environmental and other laws and regulations, competitive factors in the pipeline and energy sectors, construction and completion of capital projects, labour, equipment and material costs, access to capital markets, interest and currency exchange rates, technological developments and the current economic conditions in North America. By its nature, forward-looking information is subject to various risks and uncertainties, which could cause TCPL's actual results and experience to differ materially from the anticipated results or expectations expressed. The Company's material risks and assumptions are discussed further in TCPL's Management's Discussion and Analysis filed as document 13.2 hereto including under the headings "Pipelines Opportunities and Developments", "Pipelines Business Risks", "Energy Opportunities and Developments", "Energy Business Risks" and "Risk Management and Financial Instruments". Additional information on these and other factors is available in the reports filed by TCPL with Canadian securities regulators and with the Commission. Readers are cautioned to not place undue reliance on this forward-looking information, which is given as of the date it is expressed in this document or otherwise, and to not use future-oriented information or financial outlooks for anything other than their intended purpose. TCPL undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

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 PIPELINES LIMITED

Per: /s/ GREGORY A. LOHNES

Gregory A. Lohnes
Executive Vice-President and
Chief Financial Officer

Date: February 26, 2010

DOCUMENTS FILED AS PART OF THIS REPORT

13.1 TCPL's Annual Information Form for the year ended December 31, 2009.
13.2 Management's Discussion and Analysis (included on pages 2 through 88 of the TCPL 2009 Management's Discussion and Analysis and Audited Consolidated Financial Statements).
13.3 2009 Audited Consolidated Financial Statements (included on pages 89 through 142 of the TCPL 2009 Management's Discussion and Analysis and Audited Consolidated Financial Statements).
13.4 Related supplementary note entitled "Reconciliation to United States GAAP" and the auditors' report thereon.
13.5 Management's Report on Internal Control Over Financial Reporting.
13.6 Report of the Independent Registered Public Accounting Firm on the effectiveness of TCPL's Internal Control Over Financial Reporting, as at December 31, 2009.
99.1 Comments by Auditors for United States Readers on Canada-United States Reporting Differences.

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 PIPELINES LIMITED

ANNUAL INFORMATION FORM

February 22, 2010

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PRESENTATION OF INFORMATION

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

Unless otherwise noted, the information contained in this AIF is given at or for the year ended December 31, 2009 (*Year End*). Amounts are expressed in Canadian dollars unless otherwise indicated. Financial information is presented in accordance with Canadian generally accepted accounting principles (*Canadian GAAP*).

Certain portions of TCPL s Management s Discussion and Analysis dated February 22, 2010 (*MD&A*) are incorporated by reference into this AIF as stated below. The MD&A can be found on SEDAR at www.sedar.com under TCPL s profile.

The Accounting Standards Board (*AcSB*) of the Canadian Institute of Chartered Accountants has announced that Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards (*IFRS*), as issued by the International Accounting Standards Board, effective January 1, 2011. Effective January 1, 2011, TCPL will begin reporting under IFRS. TCPL s conversion plan includes obtaining skilled people, providing education and training, analyzing the impact on TCPL of key differences between Canadian GAAP and IFRS, and developing and executing a phased approach to conversion and implementation. For more information on TCPL s conversion project, see TCPL s MD&A under Accounting Changes International Financial Reporting Standards .

Information relating to metric conversion can be found at Schedule A to this AIF. Terms defined throughout this AIF are listed in the Glossary found at the end of this AIF.

FORWARD LOOKING INFORMATION

This AIF, the documents incorporated by reference into this AIF, and other reports and filings made with the securities regulatory authorities may contain certain information that is forward looking and is subject to important risks and uncertainties. The words anticipate , expect , believe , may , should , estimate , project , outlook , forecast or other similar words are used to identify such forward looking information. Forward-l statements in this document are intended to provide securityholders and potential investors with information regarding TCPL and its subsidiaries, including management s assessment of TCPL s and its subsidiaries future financial and operational plans and outlook. Forward-looking statements in this document may include, among others, statements regarding the anticipated business prospects and financial performance of TCPL and its subsidiaries, expectations or projections about the future, strategies and goals for growth and expansion, expected and future cash flows, costs, schedules, operating and financial results and expected impact of future commitments and contingent liabilities. All forward looking statements reflect TCPL s beliefs and assumptions based on information available at the time the statements were made. Actual results or events may differ from those predicted in these forward-looking statements. Factors that could cause actual results or events to differ materially from current expectations include, among others, the ability of TCPL to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the operating performance of the Company s pipeline and energy assets, the availability and price of energy commodities, capacity payments, regulatory processes and decisions, changes in environmental and other laws and regulations, competitive factors in the pipeline and energy sectors, construction and completion of capital projects, labour, equipment and material costs, access to capital markets, interest and currency exchange rates, technological developments and economic conditions in North America. By its nature, forward looking information is subject to various risks and uncertainties, including those material risks discussed in this AIF under Risk Factors , which could cause TCPL s actual results and experience to differ materially from the anticipated results or expectations expressed. Additional information on these and other factors is available in the reports filed by TCPL with Canadian securities regulators and with the U.S. Securities and Exchange Commission (*SEC*). Readers are cautioned to not place undue reliance on this forward looking information, which is given as of the date it is expressed in this AIF or otherwise, and to not use future-oriented information or financial outlooks for anything other than their intended purpose. TCPL undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

TRANSCANADA PIPELINES LIMITED

Corporate Structure

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

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

Date		**Event**
March 21, 1951		Incorporated by Special Act of Parliament as Trans-Canada Pipe Lines Limited.
April 19, 1972		Continued under the *Canada Corporations Act* by Letters Patent, which included the alteration of its capital and change of name to TransCanada PipeLines Limited.
June 1, 1979		Continued under the *Canada Business Corporations Act.*
July 2, 1998		Certificate of Arrangement issued in connection with the Plan of Arrangement with NOVA Corporation (*NOVA*) under which the companies merged and then split off the commodity chemicals business carried on by NOVA into a separate public company.
January 1, 1999		Certificate of Amalgamation issued reflecting TCPL s vertical short form amalgamation with a wholly owned subsidiary, Alberta Natural Gas Company Ltd.
January 1, 2000		Certificate of Amalgamation issued reflecting TCPL s vertical short form amalgamation with a wholly owned subsidiary, NOVA Gas International Ltd.
May 4, 2001		Restated TransCanada PipeLines Limited Articles of Incorporation filed.
June 20, 2002		Restated TransCanada PipeLines Limited By-Laws filed.
May 15, 2003		Certificate of Arrangement issued in connection with the plan of arrangement with TransCanada. TransCanada was incorporated pursuant to the provisions of the Canada *Business Corporations Act* on February 25, 2003. The arrangement was approved by TCPL common shareholders on April 25, 2003 and following court approval, Articles of Arrangement were filed making the arrangement effective May 15, 2003. 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.

Intercorporate Relationships

The following diagram presents the name and jurisdiction of incorporation, continuance or formation of TCPL s principal subsidiaries as at December 31, 2009. Each of these subsidiaries has total assets that exceeded 10% of the total consolidated assets of TransCanada or revenues that exceeded 10% of the total consolidated revenues of TransCanada as at and for the year ended December 31, 2009. TCPL owns, directly or indirectly, 100 per cent of the voting shares of each of these subsidiaries.

The above diagram does not include all of the subsidiaries of TCPL. The assets and revenues of excluded subsidiaries in the aggregate did not exceed 20% of the total consolidated assets or total consolidated revenues of TCPL as at and for the year ended December 31, 2009.

GENERAL DEVELOPMENT OF THE BUSINESS

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

TCPL s reportable business segments are Pipelines and Energy. Pipelines are principally comprised of the Company s pipelines in Canada, the U.S. and Mexico and its regulated natural gas storage operations in the U.S. Energy includes the Company s power operations and the non-regulated natural gas storage business.

Developments in the Pipelines Business

TCPL s strategy in Pipelines is focused on both growing its North American natural gas and crude oil transmission network and maximizing the long-term value of its existing pipeline assets. Summarized below are significant developments that have occurred in TCPL s Pipelines business over the last three years.

2010

Pipeline Developments

- January 29, 2010. TCPL announced that the proposed Alaska pipeline project (the *Alaska Pipeline Project*) filed its plan with the United States Federal Energy Regulatory Commission (*FERC*) to obtain approval to conduct an open season. If approval is granted, an open season offering is expected to be provided to potential shippers at the end of April 2010 for their assessment until July 2010. The Alaska Pipeline Project is a 4.5 billion cubic feet per day (*Bcf/d*) natural gas pipeline that would extend 2,737 kilometres (*km*) (1,700 miles) from a new natural gas treatment plant at Prudhoe Bay, Alaska to Alberta.

Regulatory Matters

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February 19, 2010. TCPL filed an application with the National Energy Board (*NEB*) for approvals to construct and operate the proposed Horn River pipeline project (*Horn River Project*), a 158 km (98 mile) pipeline and related facilities to connect new shale gas supply in the Horn River basin north of Fort Nelson, B.C., to TCPL s natural gas transmission system in the province of Alberta (the *Alberta System*). The Horn River Project will consist of approximately 74 km of new pipelines and the purchase and use of an existing pipeline in the Horn River area and will transport sweet natural gas to a tie in point on the Alberta System. The project is expected to cost approximately $307 million.

2009

Pipeline Developments

- February 26, 2009. TCPL announced the successful completion of a binding open season, securing support for firm transportation contracts of 378 million cubic feet per day (*MMcf/d*) for the Horn River Project. Total contractual commitments for the Horn River Project increased to 503 MMcf/d by 2014 as a result of newly contracted volumes from a recently announced natural gas processing facility that will be located in the Horn River area.

- May 7, 2009. TCPL announced that it was the successful bidder on a contract to build, own and operate a US$320 million pipeline in Mexico, which is supported by a twenty-five year contract for its entire capacity with Comisión Federal de Electridad, Mexico s state-owned electric power company. The proposed pipeline, known as the Guadalajara Pipeline, is an approximately 305 km (190 mile) pipeline capable of transporting 500 MMcf/d of natural gas, and is proposed to extend from a liquefied natural gas terminal under construction near Manzanillo on Mexico s Pacific Coast to Guadalajara, the second largest city in Mexico. Regulatory approvals were received in December 2009 and construction is under way with an expected in-service date of first quarter 2011.

- June 11, 2009. TCPL reached an agreement with ExxonMobil Corporation to jointly advance the Alaska Pipeline Project. A joint project team is developing the engineering, environmental, aboriginal relations and commercial work.

- July 1, 2009. TCPL completed the sale of North Baja Pipeline, LLC (*North Baja*) to its affiliate TC PipeLines, LP. As part of the transaction, TCPL agreed to amend its incentive distribution rights with TC PipeLines, LP. Under the amendment, TCPL received additional common units in exchange for a resetting of its incentive distribution rights at a lower percentage which escalates with increases in TC PipeLines, LP distributions. The aggregate consideration received from the partnership included a combination of cash and common units totaling approximately US$395 million. With the close of the transaction, TCPL s ownership of the partnership increased to 42.6 per cent. TCPL continued to operate North Baja following the transfer of ownership. The system is a 129 km (80 mile) natural gas pipeline that extends from southwest Arizona to a point on the California/Mexico border and connects with a natural gas pipeline system in Mexico. TCPL s ownership in TC PipeLines, LP was subsequently reduced to 38.2 per cent in November 2009 after TC PipeLines, LP completed a public issuance of common units.

- August 14, 2009. TCPL became the sole owner of the 3,456 km (2,147 mile) Keystone Oil Pipeline project that will transport crude oil from Alberta to markets in the United States (the *Keystone Oil Pipeline*) through the purchase of ConocoPhillips remaining approximately 20 per cent interest for US$553 million and the assumption of US$197 million of short-term debt. TCPL also assumed the responsibility for ConocoPhillips share of the capital investment required to complete the project resulting in an incremental commitment of approximately US$1.7 billion through the end of 2012.

- September 28, 2009. TCPL began work on the final phase of the North Central Corridor natural gas pipeline, a 300 km (186 mile) extension of the northern section of the Alberta System. This 160 km Red Earth section is expected to be complete by April 2010. The 140 km North Star section has been completed and two 13 Megawatt (*MW*) compressor units at the Meikle River compressor station were operational on May 15, 2009 and August 21, 2009, respectively.

- December 2009. A Joint Review Panel of the Canadian government released a report on environmental and socio-economic factors relating to the Mackenzie Gas Pipeline Project, a proposed 1,200 km (746 mile) natural gas pipeline to extend from a point near Inuvik, Northwest Territories to the northern border of Alberta, where it will connect to the Alberta System. The report has been submitted to the NEB as part of the review process for approval of the project. A decision is currently expected by fourth quarter 2010. TransCanada continues funding of the Mackenzie Valley Aboriginal Pipeline Limited Partnership for its participation in the Mackenzie Gas Pipeline Project.

Regulatory Matters

- February 26, 2009. The NEB approved TCPL s application for federal regulation of its Alberta System, which regulation became effective April 29, 2009. The Alberta System was previously regulated by the Alberta Utilities Commission (*AUC*). Under federal regulation, TCPL is able to apply to the NEB for approval to extend the Alberta System across provincial borders, allowing the Company to provide service to producers outside of Alberta.

- March 20, 2009. TransCanada Québec & Maritimes Pipeline Inc. (*TQM*) received the NEB s decision on its cost of capital application for 2007 and 2008, which requested an 11 per cent return on 40 per cent deemed common equity. The NEB set a 6.4 per cent after-tax weighted average cost of capital for each of the two years, which equates to a 9.85 per cent return on 40 per cent deemed common equity in 2007 and a 9.75 per cent return on 40 per cent deemed common equity in 2008. Prior to the decision, TQM was subject to the NEB return on equity formula of 8.46 per cent and 8.71 per cent for 2007 and 2008, respectively, on deemed common equity of 30 per cent. In June 2009, the NEB approved TQM s final tolls for 2007 and 2008, which reflected the 6.4 per cent after-tax weighted average cost of capital.

- May 2009. Portland Natural Gas Transmission System (*Portland System*) reached a settlement with its customers on certain short-term issues contained in its general rate case filed with the FERC in April 2008, which proposed a rate increase of approximately six per cent as well as other changes to its tariff. The partial settlement was filed with the FERC for approval and a decision is expected in 2010. The remaining issues were litigated and the initial decision from the administrative law judge was issued in December 2009. Participants in the rate case have an opportunity to respond to the initial decision. The FERC is expected to issue its final decision on the litigated portion of the rate case in fourth quarter 2010.

- September 2009. The NEB held a hearing to review TCPL s application regarding the Canadian portion of the planned expansion and extension of the Keystone Oil Pipeline, which expansion is expected to provide additional capacity in 2013 of 500,000 barrels per day (*Bbl/d*) from Western Canada to the United States Gulf Coast, near existing terminals in Port Arthur, Texas. The expansion, when completed, is expected to increase the capacity of the Keystone Oil Pipeline system from 591,000 Bbl/d to approximately 1.1 million Bbl/d. The NEB is expected to issue a decision in first quarter 2010. Permits for the U.S. portion of the expansion are expected by fourth quarter 2010.

Construction of the expansion facilities is expected to commence in first quarter 2011 subject to the receipt of the necessary regulatory approvals.

- October 8, 2009. The NEB determined that its RH-2-94 decision would no longer be in effect. The RH-2-94 decision pursuant to the National Energy Board Act (Canada) established a return on equity formula tied to the Government of Canada bond yields that had formed the basis for determining tolls for certain pipelines under NEB jurisdiction since January 1, 1995. The NEB decided that the cost of capital would be determined by negotiations between pipeline companies and their shippers or by the NEB if a pipeline company filed a cost of capital application. The decision affects the calculation of future tolls for TCPL s NEB-regulated natural gas pipelines. In November 2009, the Canadian Association of Petroleum Producers and the Industrial Gas Users Association sought leave to appeal the October 2009 NEB decision to the Federal Court of Appeal and named the NEB as the sole respondent. In January 2010, TCPL was granted respondent status in the matter and in February 2010 filed its submission opposing the leave application.

- November 2009. The NEB concluded a public hearing process on TCPL s application for approval to construct and operate the Groundbirch pipeline, which is comprised of a 77 km (48 mile) natural gas pipeline and related above ground facilities. TCPL has entered into firm transportation agreements with Groundbirch customers that are expected to increase to 1.1 Bcf/d by 2014. The Groundbirch pipeline, if approved, would be an extension of the Alberta System and would connect natural gas supply primarily from the Montney shale gas formation in northeast British Columbia to existing infrastructure in northwest Alberta. Construction of the Groundbirch pipeline is expected to commence in July 2010 with completion anticipated in November 2010. The NEB is expected to issue a decision in first quarter 2010.

- November 2009. The FERC initiated an investigation to determine whether rates on the Great Lakes system, a natural gas pipeline system running from northwestern Idaho, through Washington and Oregon to the California border (the *Great Lakes System*) are just and reasonable. In response, Great Lakes filed a cost and revenue study with the FERC on February 4, 2010. A hearing is scheduled to commence on August 2, 2010, and an initial decision is required in November 2010. The impact of the investigation on the Great Lakes System s rates and revenues is unknown at this time.

- November 27, 2009. TCPL filed a combined application with the NEB for approvals of both a new Alberta System Rate Design Settlement, and the integration of Canadian Utilities Limited (*ATCO Pipelines*). The rate design was negotiated with all key stakeholders and addresses the evolving nature of the Alberta System and the integration of ATCO Pipelines. It also incorporates a single delivery service for all delivery points resulting from the amalgamation of current intra-Alberta and export delivery services. TCPL reached a proposed agreement with ATCO

Pipelines to provide integrated natural gas transmission service to customers on September 8, 2008. If approved by the regulatory authorities, the two companies will combine physical assets under a single rates and services structure with a single commercial interface with customers but with each company separately managing assets within distinct operating territories in the province. TCPL and ATCO Pipelines continue to work towards obtaining the necessary regulatory approvals to provide integrated service to shippers on the Alberta System and the ATCO Pipelines system. The integration of the Alberta System and ATCO Pipelines system will create the effect of a single integrated natural gas transmission system in Alberta resulting in a more efficient delivery of service to customers.

- December 2009. The NEB approved TCPL s application for 2010 final tolls for its Canadian gas pipeline system (the *Canadian Mainline*) transportation service, effective January 1, 2010. The 2010 calculated ROE for the Canadian Mainline will be 8.52 per cent, a decrease from 8.57 per cent in 2009. The Canadian Mainline will continue to base its return on the NEB s return on equity formula for 2010 and 2011 in accordance with the terms of the current Canadian Mainline tolls settlement. Reduced throughput and greater use of shorter distance transportation contracts has resulted in an increase in Canadian Mainline tolls for 2010 compared to 2009. This situation, coupled with the ongoing development and growth of competitive alternative natural gas supply and infrastructure from the United States shale gas regions, is increasing competitive pressures on the Canadian Mainline. As a result, TCPL indicated that it will develop solutions, involving possible changes to business model, rate design, and services that would be designed to increase throughput and revenue in order to reduce tolls. TCPL is also pursuing the connection of new sources of U.S. gas supply to the existing Canadian Mainline infrastructure to maintain its existing markets and competitive position.

- December 2009. The FERC issued a Final Environmental Impact Statement (*FEIS*) for the Bison Pipeline Project (*Bison*), a proposed 487 km (303 mile) pipeline from the Powder River Basin in Wyoming to the Northern Border Pipeline system in Morton County, North Dakota.

2008

Pipeline Developments

• February 2008. In 2005, certain subsidiaries of Calpine Corporation (*Calpine*) filed for bankruptcy protection in both Canada and the U.S. The Portland System and Gas Transmission Northwest Corporation (*GTNC*) reached agreement with Calpine for allowed unsecured claims in the Calpine bankruptcy of US$125 million and US$192.5 million, respectively. Creditors were to receive shares in the re-organized Calpine and these shares would be subject to market price fluctuations as the new Calpine shares began to trade. In February 2008, the Portland System and GTNC received partial distributions of 6.1 million shares and 9.4 million shares, respectively. Subsequently, these shareholdings were sold into the market. Claims of NOVA Gas Transmission Limited (*NGTL*) and Foothills Pipe Lines (South B.C.) Ltd., both wholly-owned subsidiaries of TransCanada, for $31.6 million and $44.4 million, respectively, were received in cash in January 2008 and were passed on to shippers on these systems.

• March 14, 2008. TransCanada Keystone Pipeline, LP (*Keystone U.S.*) received a Presidential Permit authorizing the construction, maintenance and operation of facilities at the United States and Canada border for the transportation of crude oil between the two countries. The Presidential Permit was a significant regulatory approval required to begin construction of the Keystone Oil Pipeline. The Presidential Permit was issued following the issuance by the U.S. Department of State of the FEIS on January 11, 2008 for the construction of the Keystone U.S. pipeline and its Cushing extension. The FEIS stated the pipeline would result in limited adverse environmental impacts. Construction of the Keystone Oil Pipeline began in May 2008 in both Canada and the United States. Commissioning of the segment to Wood River and Patoka commenced in late 2009 with commercial operations expected to follow in mid-2010. Commissioning of the segment providing service to Cushing is expected to commence in late 2010.

• April 2008. An expansion to TCPL s Alberta System in the Fort McMurray area, comprising a total of approximately 150 km (93 miles), was placed in service on its projected on-stream date.

• July 16, 2008. TCPL announced plans to expand and extend the Keystone Oil Pipeline system and provide additional capacity in 2013 of 500,000 Bbl/d from Western Canada to the United States Gulf Coast, near existing terminals in Port Arthur, Texas.

- September 3, 2008. TCPL acquired Bison Pipeline LLC from Northern Border Pipeline Company (*NBPL*) for US$20 million. The assets of Bison Pipeline LLC included executed precedent agreements as well as regulatory, environmental and engineering work on Bison.

- October 29, 2008. TCPL announced that the Keystone Oil Pipeline system successfully conducted an open season for expansion and extension to the United States Gulf Coast by securing additional firm, long-term contracts on the system.

- December 5, 2008. The Alaska Commissioner of Revenue and Natural Resources issued the *Alaska Gasline Inducement Act* (*AGIA*) license to TCPL to advance the Alaska Pipeline Project, following the approval by the Alaska Senate on August 1, 2008 of TCPL s application for the license. TCPL has committed under the AGIA to advance the Alaska Pipeline Project through an open season and subsequent FERC certification. TCPL has commenced the engineering, environmental, field and commercial work. Under AGIA, the State of Alaska has agreed to reimburse a share of the eligible pre-construction costs to TCPL to a maximum of US$500 million.

- TCPL agreed to increase its equity ownership in Keystone U.S. and TransCanada Keystone Pipeline Limited Partnership (*Keystone Canada*) up to 79.99 per cent from 50 per cent with ConocoPhillips equity ownership being reduced concurrently to 20.01 per cent through sole funding of cash calls.

Regulatory Matters

- January 2008. GTNC, a wholly-owned subsidiary of TransCanada, filed a Stipulation and Agreement with the FERC on October 31, 2007 comprised of an uncontested settlement of all aspects of its 2006 General Rate Case. On January 7, 2008, the FERC issued an order approving the settlement. The settlement rates were effective retroactive to January 1, 2007.

- March 18, 2008. TCPL filed an application with the NEB to increase the interim tolls on the Canadian Mainline previously approved in December 2007. This toll increase was a result of a significant decrease in forecasted flows on the Canadian Mainline and was intended to allow TCPL to meet its 2008 revenue requirement. On March 28, 2008, the NEB approved the amended interim tolls for transportation service effective April 1, 2008.

- June 17, 2008. TCPL filed an application with the NEB to establish federal regulation for TCPL s Alberta System. An oral hearing to discuss this matter began on November 18, 2008, concluded on November 28, 2008 and a decision was issued on February 26, 2009.

- June, 2008. The NEB approved TCPL s application for additional pumping facilities required to expand the Canadian portion of the Keystone Oil Pipeline project from a nominal capacity of approximately 435,000 Bbl/d to 591,000 Bbl/d to accommodate volumes to be delivered to the Cushing markets, after holding an oral hearing on April 8, 2008. The hearing and decision followed on an application filed by Keystone Canada with the NEB in November 2007.

- October 10, 2008. The AUC approved TCPL s application for a permit to construct the North Central Corridor expansion, at a cost of approximately $925 million. Construction on the project began in October 2008. The decision followed on a non-routine application filed with the Alberta Energy and Utilities Board (*EUB*) on November 20, 2007.

- December 17, 2008. The AUC approved NGTL s 2008-2009 Revenue Requirement Settlement Application as filed, in its entirety. As part of the settlement, fixed costs were established for operation, maintenance and administration costs, return on equity and income taxes. Any variances between actual costs and those agreed to in the settlement accrue to TCPL, subject to a return on equity and income tax adjustment mechanism, which accounts for variances between actual and settlement rate base and income tax assumptions. The other cost elements of the settlement are treated on a flow-through basis. The AUC also approved the 2008 interim rates of NGTL on a final basis for the period January 1, 2008 to December 31, 2008.

- December 2008. Palomar Gas Transmission LLC applied to the FERC for a certificate to build the 349 km (217 mile) Palomar pipeline which would extend from the GTN System (as defined below) in central Oregon to the Columbia River northwest of Portland. The proposed Palomar pipeline is a 50/50 joint venture of GTNC and Northwest Natural Gas Co. Palomar is currently in discussions with potential shippers to secure additional shipping commitments for the project.

2007

Pipeline Developments

- February 9, 2007. TCPL received approval from the NEB to transfer a section of its Canadian Mainline transmission facilities to the Keystone Oil Pipeline project to transport crude oil from Alberta to refining centres in the U.S. Midwest and to construct and operate new oil pipeline facilities in Canada. TCPL announced in January 2007 the start of a binding open season for an expansion and extension of the proposed Keystone Oil Pipeline. The purpose of the open season was to obtain binding commitments to support the expansion of the proposed Keystone Oil Pipeline from approximately 435,000 Bbl/d to 591,000 Bbl/d and the construction of a 468 kilometre extension of the U.S. portion of the pipeline.

- February 22, 2007. TCPL closed its acquisitions of American Natural Resources Company and ANR Storage Company (collectively, *ANR*) and acquired an additional 3.6 per cent interest in Great Lakes Gas Transmission Limited Partnership (*Great Lakes*) from El Paso Corporation for a total of US$3.4 billion, subject to certain post-closing adjustments, including approximately US$491 million of assumed long-term debt. Additionally, TCPL increased its ownership in TC PipeLines, LP to 32.1 per cent in conjunction with the TC PipeLines, LP acquisition of a 46.4 per cent interest in Great Lakes. The acquisition was financed partly through an offering of 39,470,000 subscription receipts at $38.00 per subscription receipt, which resulted in gross proceeds to TCPL of approximately $1.725 billion including the exercise of an over-allotment option granted to the underwriters. Upon closing of the acquisition of ANR, the subscription receipts were automatically exchanged, without the payment of any additional consideration by the subscribers, on a one-to-one basis for common shares of TransCanada (*Common Shares*).

- December 2007. ConocoPhillips contributed $207 million to acquire a 50 per cent ownership interest in the Keystone Oil Pipeline.

Regulatory Matters

- February 2007. TCPL received approval from the NEB to integrate its natural gas pipeline system in southern British Columbia with its natural gas pipeline systems in southern Alberta and southwestern Saskatchewan (collectively, the *Foothills System*) effective April 1, 2007.

- May 2007. TCPL s five-year settlement with interested stakeholders for the years 2007 to 2011 on its Canadian Mainline was approved by the NEB. The settlement reflects, among other things, a deemed common equity ratio of 40 per cent.

Further information about developments in the Pipelines business can be found in the MD&A under the headings TCPL s Strategy , Pipelines Highlights , and Pipelines Opportunities and Developments .

Developments in the Energy Business

TCPL has built a substantial energy business over the past decade and has achieved a major presence in power generation in selected regions of Canada and U.S. More recently, TCPL has also developed a substantial non-regulated natural gas storage business in Alberta. Summarized below are significant developments that have occurred in TCPL s energy business over the last three years.

2009

Energy Developments

- February 19, 2009. The FERC approved two separate applications filed by TCPL on December 19, 2008 requesting approval to charge negotiated rates and to proceed with an open season in the spring of 2009 for each of the Zephyr (*Zephyr*) and Chinook (*Chinook*) transmission line projects. Both projects are proposed 500 kilovolt high voltage direct current transmission projects. Zephyr is a proposed 1,760 km (1,100 mile) transmission line that would originate in Wyoming, and Chinook is a proposed 1,600 km (1,000 mile) project that would originate in Montana. Both projects would terminate in Nevada, and it is anticipated that each would deliver primarily wind generated electricity to markets in the southwestern United States. The open seasons commenced on October 13, 2009 and closed in December 2009. A comprehensive review of the bids submitted for each project will be undertaken.

- April 2009. Portlands Energy Centre, a natural gas fired combined-cycle power plant near downtown Toronto, Ontario (*Portlands Energy Centre*) was fully commissioned, ahead of time and under budget. Portlands Energy Centre, which is 50 per cent owned by TCPL, is able to provide 550 MW of electricity under a 20 year Accelerated Clean Air Supply contract with the Ontario Power Authority.

- June 9, 2009. Hydro-Québec Distribution notified the Régie the L énergie that it would exercise its option to extend the suspension of all electricity generation from TCPL s 550 MW Bécancour cogeneration power plant near Trois-Rivières, Québec (*Bécancour*) through 2010. This followed on TCPL s agreement with Hydro-Québec Distribution to temporarily suspend all electricity generation from Bécancour during 2009. TCPL will continue to receive payments under the agreement similar to those that would have been received under the normal course of operation.

- July 2009. Bruce Power and the Ontario Power Authority amended certain terms and conditions included in the Bruce Power Refurbishment Implementation Agreement. The amendments are consistent with the intent of the agreement, originally signed in 2005, and recognize the significant changes in Ontario s electricity market. Under the original agreement, Bruce Power A L.P. (*Bruce A*) committed to refurbish and restart the currently idle Units 1 and 2, extend the operating life of Unit 3 and replace the steam generators on Unit 4. An amendment in 2007 provided for a full refurbishment of Unit 4, which will extend the expected operating life of the unit. This most recent amendment included amendments to the Bruce Power L.P. (*Bruce B*) floor price mechanism, the removal of a support payment cap for Bruce A, an amendment to the capital cost-sharing mechanism, and provision for deemed generation payments to Bruce Power at the contract prices under circumstances where generation from Bruce A and Bruce B is reduced due to system curtailments on the Independent Electricity System Operator controlled grid in Ontario. The Bruce A Unit 1 and 2 refurbishment and restart project continues. Unit 2 is expected to be restarted in mid-2011 with the Unit 1 restart to follow approximately four months later. TCPL expects its share of the capital costs to complete the project to be approximately $2 billion. Bruce Power continues to advance an initiative to further extend the operating lives of Units 3 and 4. Unit 4 is now expected to continue to operate beyond 2018 and plans are in place to implement an extensive maintenance program that, if successful and approved by the Canadian Nuclear Safety Commission, would result in the life of Unit 3 being extended for a similar period of time.

- August 2009. TCPL began construction of the US$500 million Coolidge Generating Station (*Coolidge*), a 575 MW simple-cycle natural gas-fired peaking power generation station to be located 72 km (45 miles) southeast of Phoenix in Coolidge, Arizona. The facility is expected to be placed in service in second quarter 2011.

- September 30, 2009. The Ontario Power Authority advised TCPL that it was awarded a 20-year clean energy supply contract to build, own and operate the 900 MW Oakville Generating Station in Oakville, Ontario. TCPL expects to invest approximately $1.2 billion in the natural gas fired combined cycle plant which is scheduled to be in service in first quarter 2014. Commencement of construction of the project is dependent on receipt of permits and approvals from the municipal authority and on approval from the Ministry of Environment on impacts such as air quality and noise.

- October 9, 2009. Operations began at the Kibby Wind Power Project in northern Franklin County, Maine, with half of the project s 44 wind turbines operational by October 30, 2009. The second phase is under construction and is expected to be in service in third quarter 2010. The Kibby Wind Power Project is expected to have the capacity to produce 132 MW. Capital cost is expected to be approximately US$320 million.

- Third quarter 2009. Construction activity began on the 212 MW Gros-Morne and 58 MW Montagne-Sèche wind farms. These are the fourth and fifth Québec based wind farms of a wind energy project contracted by Hydro-Québec Distribution in the Gaspé Region of Québec (the *Cartier Wind Energy Project*), which is 62 per cent owned by TCPL. The Montagne-Sèche project and phase one of the Gros-Morne project (101 MW) are expected to be operational by 2011. Phase two of the Gros-Morne project (111 MW) is expected to be operational by 2012.

Regulatory Matters

- April 13, 2009. The United States Secretary of Commerce issued its decision denying the appeal filed by Broadwater Energy, LLC on the ruling by the New York State Department of State (*NYSDOS*) regarding the Broadwater liquefied natural gas (*LNG*) project (*Broadwater*). A joint venture with Shell U.S. Gas & Power LLC, Broadwater is a proposed offshore LNG facility in Long Island Sound, New York, which received approval by FERC in March 2008. In April 2008, NYSDOS determined that construction and operation of the project would not be consistent with the state s coastal zone policies. Broadwater Energy, LLC filed the appeal on the decision of the NYSDOS on June 6, 2008, asking the Secretary of Commerce to override the NYSDOS decision on the basis that the project meets the criteria for approval under the Coastal Zone Management Act and applicable regulations.

2008

Energy Developments

- January 2008. A milestone in the Bruce A Units 1 and 2 refurbishment and restart project was completed when the sixteenth and final new steam generator was installed. This process was expected to result in a further increase in the total project cost to complete the Unit 1 and 2 restart. Project cost increases are subject to the capital cost-sharing mechanism under the agreement with the Ontario Power Authority, as amended in July 2009. Bruce A Units 1 and 2 are expected to produce 1,500 MW when completed.

- February 2008. The potential anchor LNG supplier for the Cacouna LNG project (*Cacouna*) terminal in Québec announced it would no longer be pursuing the development of its LNG supply as originally planned. Although Cacouna received its primary regulatory approvals, project development has been suspended until alternate LNG supply is acquired and the North American market for LNG grows.

- April 2008. A comprehensive review of costs to complete the Bruce A Units 1 and 2 refurbishment and restart project was completed. Based on this assessment, the capital cost for the restart and refurbishment of Bruce A Units 1 and 2 was expected to be approximately $3.4 billion, up from an original 2005 cost estimate of $2.75 billion. TCPL s share was expected to be approximately $1.7 billion compared to an original estimate of $1.4 billion.

- May 12, 2008. TCPL announced that the Phoenix, Arizona based utility, Salt River Project Agricultural Improvement and Power District, signed a 20 year power purchase agreement to secure 100 per cent of the output from Coolidge. In December 2008, the Arizona Corporation Commission granted a Certificate of Environmental Compatibility approving Coolidge.

- July 9, 2008. TCPL announced that the Kibby Wind Power Project received unanimous final development plan approval from Maine s Land Use Regulation Commission. Construction on the project began in July 2008. Commissioning of the first phase occurred in October 2009.

- August 26, 2008. TCPL completed its acquisition of the 2,480 MW Ravenswood Generating Station (*Ravenswood*) located at Queen s, New York for US$2.9 billion, subject to certain post-closing adjustments. The acquisition was completed pursuant to a purchase agreement with KeySpan Corporation and certain subsidiaries. The acquisition was financed through a combination of equity and term debt offerings, funds drawn on a newly established bridge loan facility and cash on hand (see Financing Activities below).

- November 22, 2008. The Carleton wind farm, the third of five phases of the Cartier Wind Energy Project, went into service and is capable of generating 109 MW of power.

- In fourth quarter 2008, Bruce Power completed a review of the end of life estimates for Units 3 and 4. As a result of the review, Unit 3 was expected to be in commercial service until 2011, providing an additional two years of generation before refurbishment. After the refurbishment, the end of life estimate for Unit 3 was to be extended to 2038. The review also showed that Unit 4 was expected to remain in commercial service until 2016, providing seven years of generation before refurbishment after which the end of life estimate for Unit 4 was expected to be extended to 2042.

Regulatory Matters

- January 11, 2008. The FERC issued its FEIS for Broadwater. The FEIS confirmed project need, supported the location of the project with acknowledgement of its target market and delivery goals, and found safety and security risks to be limited and acceptable. The FEIS concluded that with adherence to federal and state permit requirements and regulations, Broadwater s proposed mitigation measures and the FERC s recommendations, the project would not result in a significant impact on the environment.

- March 24, 2008. FERC authorized the construction and operation of Broadwater, subject to the conditions reflected in the authorization. On April 10, 2008, the NYSDOS determined that construction and operation of the project would not be consistent with the state s coastal zone policies. As a result of this unfavourable decision, TCPL wrote down $27 million after tax of costs for Broadwater that had been capitalized to March 31, 2008. On June 6, 2008, Broadwater Energy, LLC filed an appeal with the United States Secretary of Commerce.

2007

Energy Developments

- June 2007. Following public hearings in 2006, the Québec government granted a provincial decree approving Cacouna. Cacouna also received federal approvals pursuant to the *Canadian Environmental Assessment Act*.

- September 2007. Cacouna announced that it was delaying the planned in-service date for the regasification terminal from 2010 to 2012. This delay resulted from a need to assess impacts of permit conditions, to review the facility design in light of escalating costs and to align the schedule with potential LNG supply facilities.

- November 2007. The second phase of the Cartier Wind Energy Project, the 101 MW Anse-à-Valleau wind farm, was placed into service. In addition, the Cartier Wind Energy Project began construction of a third project, the 109 MW Carleton wind farm.

Further information about developments in the Energy business can be found in the MD&A under the headings TransCanada s Strategy , Energy Highlights and Energy Opportunities and Developments .

Financing Activities

2009

- January 6, 2009. TCPL entered into an underwriting agreement with a syndicate of underwriters led by Citigroup Global Markets Inc. and HSBC Securities (USA) Inc. under which the underwriters agreed to purchase from TCPL and sell to the public US$750 million and US$1.25 billion of Senior Unsecured Notes maturing on January 15, 2019 and January 15, 2039, respectively, and bearing interest at 7.125 per cent and 7.625 per cent, respectively. The offering was completed on January 9, 2009. The proceeds from this offering were used to partially fund TCPL s capital projects, retire maturing debt obligations and for general corporate purposes. These notes were issued by way of prospectus supplement under a US$3.0 billion debt base shelf prospectus filed on January 2, 2009.

- February 17, 2009. TCPL completed the issuance of $300 million and $400 million of Medium-Term Notes maturing on February 14, 2014 and February 17, 2039, respectively, and bearing interest at 5.05 per cent and 8.05 per cent, respectively. The proceeds from these notes were used to fund the Alberta System and Canadian Mainline rate bases. These notes were issued by way of pricing supplements under a $1.5 billion debt base shelf prospectus filed in March, 2007.

- June 16, 2009. TransCanada entered into an underwriting agreement with a syndicate of underwriters led by RBC Capital Markets, BMO Capital Markets and TD Securities Inc. under which the underwriters agreed to purchase from

TransCanada 50,800,000 common shares of TransCanada (referred to in this section as *Common Shares*) and sell the Common Shares to the public at a purchase price of $31.50 per Common Share. The underwriters were also granted an over-allotment option to purchase an additional 7,620,000 Common Shares at the same price. The offering was completed on June 24, 2009 and, together with the full exercise of the over-allotment option by the underwriters, 58,420,000 Common Shares were issued resulting in gross proceeds to TransCanada of approximately $1.84 billion which were used to partially fund capital projects, including the acquisition of the remaining interests in the Keystone Oil Pipeline system, for general corporate purposes and to repay short-term indebtedness. These shares were issued by way of prospectus supplement to a $3.0 billion base shelf prospectus dated July 2, 2008.

- September 22, 2009. TransCanada entered into an underwriting agreement with a syndicate of underwriters led by Scotia Capital Inc. and RBC Capital Markets, under which the underwriters agreed to purchase from TransCanada 22,000,000 cumulative redeemable first preferred shares, series 1 (*Series 1 Preferred Shares*) and sell the Series 1 Preferred Shares to the public at a purchase price of $25.00 per share. The offering was completed on September 30, 2009 resulting in gross proceeds to TransCanada of $550 million which were used by TransCanada to partially fund capital projects, for general corporate purposes and to repay short-term indebtedness. These shares were issued by way of prospectus supplement to a $3.0 billion base shelf prospectus dated September 21, 2009.

- December 2009. TransCanada PipeLine USA Ltd. established a US$1.0 billion committed, syndicated revolving credit facility maturing December 2012, with a one year term extension at the option of the borrower. This facility is guaranteed by TCPL and was fully available at December 31, 2009.

2008

- May 5, 2008. TransCanada entered into an underwriting agreement with a syndicate of underwriters led by BMO Nesbitt Burns Inc., RBC Dominion Securities Inc., and TD Securities Inc. under which the underwriters agreed to purchase from TransCanada 30,200,000 Common Shares and sell the Common Shares to the public at a purchase price of $36.50 per Common Share. The underwriters were also granted an over-allotment option to purchase an additional 4,530,000 Common Shares at the same price. The offering was completed on May 13, 2008 and together with the full exercise of the over-allotment option by the underwriters, 34,730,000 Common Shares were issued resulting in gross proceeds to TCPL of approximately $1.27 billion to be used to partially fund acquisitions and capital projects of TCPL including, amongst others, the acquisition of Ravenswood, the construction of the Keystone Oil Pipeline, and for general corporate purposes. These Common Shares were issued by way of prospectus supplement under a $3.0 billion base shelf prospectus filed in January, 2007.

- June 27, 2008. TCPL executed an agreement with a syndicate of banks for a US$1.5 billion, committed, unsecured, one-year bridge loan facility which was extendible by the Company for an additional six month term. On August 25, 2008, TCPL used US$255 million from this facility to fund a portion of the Ravenswood acquisition and cancelled the remainder of the commitment. In February 2009, the US$255 million was repaid and the facility was cancelled.

- August 6, 2008. TCPL entered into an underwriting agreement with a syndicate of underwriters led by Citigroup Global Markets Inc. and J.P. Morgan Securities Inc. under which the underwriters agreed to purchase from TCPL and sell to the public US$850 million and US$650 million of Senior Unsecured Notes maturing on August 15, 2018 and August 15, 2038, respectively, and bearing interest at 6.50 per cent and 7.25 per cent, respectively. The offering was completed on August 11, 2008. The proceeds from these notes were used to partially fund the Ravenswood acquisition and for general corporate purposes. These notes were issued by way of prospectus supplement under a US$2.5 billion debt base shelf prospectus filed in September, 2007.

- August 20, 2008. TCPL completed the issuance of $500 million of Medium-Term Notes maturing in August 2013 and bearing interest at 5.05 per cent. The proceeds from these notes were used to partially fund the Alberta System s capital program and for general corporate purposes. These notes were issued by way of a pricing supplement under a $1.5 billion debt base shelf prospectus filed in March, 2007.

- November 17, 2008. TransCanada entered into an underwriting agreement with a syndicate of underwriters led by RBC Dominion Securities Inc., BMO Nesbitt Burns Inc., and TD Securities Inc. under which the underwriters agreed to purchase from TransCanada 30,500,000 Common Shares and sell the Common Shares to the public at a purchase price of $33.00 per Common Share. The underwriters were also granted an over-allotment option to purchase an additional 4,575,000 Common Shares at the same price. The offering was completed on November 25, 2008 and resulted in gross proceeds to TCPL of approximately $1 billion to be used by TCPL to partially fund its capital projects, including the Keystone Oil Pipeline, for general corporate purposes and to repay short-term indebtedness. The syndicate of underwriters fully exercised the over-allotment option on December 5, 2008 for additional gross proceeds to TCPL of $151 million. The Common Shares were issued by way of prospectus supplement under a $3.0 billion base shelf prospectus filed in July 2008.

- November 2008. Keystone U.S. established a US$1.0 billion committed, syndicated revolving credit facility, guaranteed by TCPL, maturing November 2010 but extendible to November 2011 at the option of the borrower. The facility was fully available at December 31, 2009 and supports a commercial paper program dedicated to funding a portion of expenditures for Keystone U.S. and for Keystone U.S. general partnership purposes.

Further information about financing activities can be found in the MD&A under the headings Short-Term Debt Financing Activities , 2009 Long-Term Debt Financing Activities , 2008 Long-Term Debt Financing Activities , 2007 Long-Term Debt Financing Activities , 2009 Equity Financing Activities , 2008 Equity Financing Activities and 2007 Equity Financing Activities .

BUSINESS OF TCPL

TCPL is a leading North American energy infrastructure company focused on pipelines and energy. At Year End, Pipelines accounted for approximately 53 per cent of revenues and 67 per cent of TCPL s total assets and Energy accounted for approximately 47 per cent of revenues and 28 per cent of TCPL s total assets. The following is a description of each of TCPL s two main areas of operation.

The following table shows TCPL s revenues from operations by segment, classified geographically, for the years ended December 31, 2009 and 2008.

Revenues From Operations *(millions of dollars)*	**2009**	**2008**
Pipelines		
Canada - Domestic	$2,389	$2,005
Canada - Export(1)	755	1,123
United States	1,585	1,522
	4,729	4,650
Energy(2)		
Canada - Domestic	2,788	2,594
Canada - Export(1)	1	2
United States	1,448	1,373
	4,237	3,969
Total Revenues(3)	$8,966	$8,619

(1) Exports include pipeline 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.

Pipelines Business

TCPL is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas pipelines, regulated gas storage facilities and projects related to oil pipelines. TCPL s network of wholly owned pipelines extends more than 60,000 km (37,282 miles), tapping into virtually all major gas supply basins in North America.

TCPL has substantial Canadian and U.S. natural gas pipeline and related holdings, and one oil pipeline project, including those listed below. The following pipelines are owned 100 per cent by TCPL unless otherwise stated.

Canada

- TCPL s Canadian Mainline is a 14,101 km (8,762 mile) natural gas transmission system in Canada that 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.

- TCPL s Alberta System is a natural gas transmission system in Alberta which gathers natural gas for use within the province and delivers it to provincial boundary points for connection with the Canadian Mainline and the Foothills System and with third party natural gas pipelines. The 23,905 km (14,854 mile) system is one of the largest carriers of natural gas in North America.

• Keystone Oil Pipeline is a 3,456 km (2,147 mile) crude oil pipeline project that will initially transport crude oil from Hardisty, Alberta to U.S. Midwest markets at Wood River and Patoka, Illinois, and to Cushing, Oklahoma. Commissioning of the segment to Wood River and Patoka began in late 2009 and commercial operation is expected to commence in mid-2010. Commissioning of the segment to Cushing is expected to begin in late 2010 and operations expected to commence in first quarter 2011. Pending regulatory approval, an expansion to the United States Gulf Coast is expected to be completed and in service in first quarter 2013, adding approximately 2,720 km (1,690 miles) of pipe to the system. In August of 2009, TCPL became the sole owner of the Keystone Oil Pipeline system.

• TCPL s Foothills System is a 1,241 km (771 mile) natural gas transmission system in Western Canada which 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. Effective April 1, 2007, the B.C. System was integrated into the Foothills System.

• TransCanada Pipeline Ventures LP owns a 161 km (100 mile) pipeline and related facilities that supply natural gas to the oilsands region of northern Alberta as well as a 27 km (17 mile) pipeline that supplies natural gas to a petrochemical complex at Joffre, Alberta.

• TQM is 50 per cent owned by TCPL. TQM is a 572 km (355 mile) pipeline system that connects with the Canadian Mainline and transports natural gas from Montréal to Québec City in Québec, and connects with the Portland System. TQM is operated by TCPL.

United States

• TCPL s ANR System (*ANR System*) is a 17,000 km (10,563 mile) natural gas transmission system which transports natural gas from producing fields located primarily in Texas and Oklahoma on its southwest leg and in the Gulf of Mexico and Louisiana on its southeast leg. The system extends to markets located mainly in Wisconsin, Michigan, Illinois, Ohio and Indiana. ANR s natural gas pipeline also connects with other natural gas pipelines providing access to diverse sources of North American supply, including Western Canada, and the mid-continent and Rocky Mountain supply regions, and a variety of markets in the Midwestern and northeastern U.S.

• Underground gas storage facilities owned and operated by ANR provide regulated gas storage services to customers on the ANR System and the Great Lakes System in upper Michigan. In 2008, ANR completed its storage enhancement project and added 14 billion cubic feet (*Bcf*) of storage. In total, the ANR business unit operates sixteen underground natural gas storage facilities throughout the State of Michigan with total natural gas storage capacity of 250 Bcf.

- The GTN System (*GTN System*) is TCPL s natural gas transmission system which extends 2,174 km (1,351 miles) and links the Foothills System and Rocky Mountain sourced natural gas with third party natural gas pipelines in Washington, Oregon and California, and with the Tuscarora Gas Transmission Company (*Tuscarora*) pipeline.

- Bison pipeline is a proposed 487 km (303 mile) natural gas pipeline from the Powder River Basin in Wyoming connecting to the Northern Border Pipeline System in North Dakota. The FERC issued a FEIS for Bison in December 2009 and the project is in the final stages of the regulatory approval process. TCPL expects to begin construction in May 2010. The Bison pipeline has shipping commitments for approximately 407 MMcf/d and is expected to be placed in-service in fourth quarter 2010.

- The Great Lakes System is owned 53.6 per cent by TCPL and 46.4 per cent by TC PipeLines, LP. The 3,404 km (2,115 mile) Great Lakes System serves markets primarily in Central Canada and the Midwestern U.S. TCPL operates the Great Lakes System and effectively owns 71.3 per cent of the system through its 53.6 per cent ownership interest and its indirect ownership, which it has through its 38.2 per cent interest in TC PipeLines, LP.

- The Northern Border Pipeline System (*NBPL System*) is 50 per cent owned by TC PipeLines, LP and is a 2,250 km (1,398 mile) natural gas transmission system, which serves the U.S. Midwest. TCPL operates and effectively owns 19.1 per cent of the NBPL System through its 38.2 per cent interest in TC PipeLines, LP.

- Tuscarora is 100 per cent owned by TC PipeLines, LP and has a 491 km (305 mile) pipeline system transporting natural gas from the GTN System at Malin, Oregon to Wadsworth, Nevada (the *Tuscarora System*) with delivery points in northeastern California and northwestern Nevada. TCPL operates the Tuscarora System and effectively owns 38.2 per cent of the system through its 38.2 per cent interest in TC PipeLines, LP.

- North Baja is 100 per cent owned by TC PipeLines, LP and is a natural gas transmission system which extends 129 km (80 miles) from Ehrenberg in southwestern Arizona to a point near Ogilby, California on the California/Mexico border and connects with a third party natural gas pipeline system in Mexico. TCPL operates the North Baja system and effectively owns 38.2 per cent of the system through its 38.2 per cent interest in TC PipeLines, LP.

- The Iroquois Gas Transmission System (*Iroquois System*) connects with the Canadian Mainline near Waddington, New York and delivers natural gas to customers in the northeastern U.S. TCPL has a 44.5 per cent ownership interest in this 666 km (414 mile) pipeline system.

- The Portland System is a 474 km (295 mile) pipeline that connects with TQM near East Hereford, Québec and delivers natural gas to customers in the northeastern U.S. TCPL has a 61.7 per cent ownership interest in the Portland System and operates this pipeline.

- TCPL holds a 38.2 per cent interest in TC PipeLines, LP, a publicly held limited partnership of which a subsidiary of TCPL acts as the general partner. The remaining interest of TC PipeLines, LP is widely held by the public. TC PipeLines, LP owns a 50 per cent interest in the NBPL System, 46.4 per cent in the Great Lakes System, 100 per cent of Tuscarora and 100 per cent of North Baja.

International

TCPL also has the following natural gas pipeline and related holdings in Mexico and South America:

- TransGas is a 344 km (214 mile) natural gas pipeline system which runs from Mariquita in the central region of Colombia to Cali in the southwest of Colombia. TCPL holds a 46.5 per cent ownership interest in this pipeline.

- Gas Pacifico is a 540 km (336 mile) natural gas pipeline extending from Loma de la Lata, Argentina to Concepción, Chile. INNERGY is an industrial natural gas marketing company based in Concepción that markets natural gas transported on Gas Pacifico. TCPL holds a 30 per cent ownership interest both in Gas Pacifico and INNERGY.

- Tamazunchale is a 130 km (81 mile) natural gas pipeline in east-central Mexico which extends from the facilities of Pemex Gas near Naranjos, Veracruz to an electricity generating station near Tamazunchale, San Luis Potosi.

- The proposed Guadalajara Pipeline is under construction and when completed will extend approximately 305 km (190 miles) from Manzanillo on Mexico s Pacific coast to Guadalajara.

Further information about TCPL s pipeline holdings, developments and opportunities and significant regulatory developments which relate to pipelines can be found in the MD&A under the headings Pipelines , Pipelines Opportunities and Developments and Pipelines Financial Analysis .

Regulation of the Pipeline Business

Canada

CANADIAN MAINLINE, TQM, FOOTHILLS AND ALBERTA SYSTEMS

Under the terms of the *National Energy Board Act* (Canada), the Canadian Mainline, TQM, Foothills, and Alberta Systems (collectively, the *Systems*) are regulated by the NEB (the Alberta System became subject to federal jurisdiction on April 29, 2009 following NEB approval of an application by TransCanada). The NEB sets tolls which provide TCPL the opportunity to recover projected costs of transporting natural gas, including the return on the average investment base for each of the Systems. In addition, new facilities are approved by the NEB before construction begins and the NEB regulates the operations of each of the Systems. Net earnings of the Systems may be affected by changes in investment base, the allowed return on equity, the level of deemed common equity and any incentive earnings.

KEYSTONE OIL PIPELINE

The NEB regulates the terms and conditions of service, including rates, and the physical operation of the Canadian portion of the Keystone Oil Pipeline. NEB approval is also required for facility additions, such as the Canadian portion of the proposed Gulf Coast expansion project, which was sought through an application in 2009. The NEB is expected to issue a decision in first quarter 2010.

United States

TCPL s wholly owned and partially owned U.S. pipelines, including the ANR System, the GTN System, the Great Lakes System, the Iroquois System, the Portland System, the NBPL System, North Baja and the Tuscarora 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 and interstate commerce.

The FERC also regulates the terms and conditions of service, including rates, on the U.S. portion of the Keystone Oil Pipeline. However, primary approvals for any facility additions to the Keystone Oil Pipeline are obtained from state agencies.

Energy Business

The Energy segment of TCPL s business includes the acquisition, development, construction, ownership and operation of electrical power generation plants, the purchase and marketing of electricity, the provision of electricity account services to energy and industrial customers, the development, construction and ownership and operation of non-regulated natural gas storage in Alberta.

The electrical power generation plants and power supply that TCPL has an interest in, including those under development, in the aggregate, represent more than 11,700 MW of power generation capacity. Power plants and power supply in Canada account for approximately 63 per cent of this total, and power plants in the U.S. account for the balance, being approximately 37 per cent.

TCPL owns and operates the following facilities:

- Ravenswood, located in Queen s, New York, is a 2,480 MW power plant that consists of multiple units employing steam turbine, combined cycle and combustion turbine technology. Ravenswood has the capacity to serve approximately 21 per cent of New York City s peak load.

- TC Hydro, TCPL s hydroelectric facilities located in New Hampshire, Vermont and Massachusetts on the Connecticut and Deerfield Rivers consists of 13 stations and associated dams and reservoirs with a total generating capacity of 583 MW.

- Ocean State Power, a 560 MW natural gas-fired, combined-cycle facility in Burrillville, Rhode Island.

- Bécancour, a 550 MW natural gas-fired cogeneration power plant located near Trois-Rivières, Québec. The entire power output is supplied to Hydro-Québec Distribution under a 20-year power purchase contract expiring in 2026. Steam is also sold to an industrial customer for use in commercial processes. Since 2008, electricity generation at the Bécancour power plant has been temporarily suspended due to an agreement entered into with Hydro-Québec. Under this agreement, TCPL continues to receive payments similar to those that would have been received under the normal course of operation.

- Natural gas-fired cogeneration plants in Alberta at Carseland (80 MW), Redwater (40 MW), Bear Creek (80 MW) and MacKay River (165 MW).

- Grandview, a 90 MW natural gas-fired cogeneration power plant located on the site of the Irving Oil Limited oil refinery in Saint John, New Brunswick. Irving Oil Limited is under a 20 year tolling arrangement that expires in 2025, to supply fuel for the plant and to contract 100 per cent of the plant s heat and electricity output.

- Cancarb, a 27 MW facility located in Medicine Hat, Alberta fuelled by waste heat from TCPL s adjacent thermal carbon black facility.

- Edson, an underground natural gas storage facility connected to the Alberta System near Edson, Alberta. The facility s central processing system is capable of maximum injection and withdrawal rates of 725 MMcf/d of natural gas. Edson has a working natural gas storage capacity of approximately 50 Bcf.

TCPL has the following long-term power purchase arrangements in place:

- TCPL has the rights to 100 per cent of the generating capacity of the 560 MW Sundance A coal-fired power generation facility under a Power Purchase Agreement (*PPA*) that expires in 2017. TCPL also has the rights to 50 per cent of the generating capacity of the 706 MW Sundance B facility under a PPA, which expires in 2020 (*Sundance*). The Sundance facilities are located in south-central Alberta.

- The Sheerness facility, which consists of two 390 MW coal-fired thermal power generating units, is located in southeastern Alberta. TCPL has the rights to 756 MW of generating capacity from the Sheerness PPA that expires in 2020 (*Sheerness*).

TCPL has interests in the following:

- Two nuclear power generating stations, Bruce A, which is owned 48.8 per cent by TCPL and has four 750 MW reactors, of which two are currently operating and two are being refurbished, and Bruce B, which is owned 31.6 per cent by TCPL and has four operating reactors with a combined capacity of approximately 3,200 MW. Bruce Power is two partnerships with generating facilities and offices located on 2,300 acres northwest of Toronto, Ontario on which are housed Bruce A and Bruce B.

- A 60 per cent ownership in CrossAlta, which is a 68 Bcf underground natural gas storage facility connected to the Alberta System near Crossfield, Alberta. The facility s central processing system is capable of maximum injection and withdrawal rates of 550 MMcf/d of natural gas.

- A 62 per cent interest in the Carleton (109 MW), Anse-à-Valleau (101 MW), and Baie-des-Sables (110 MW) wind farms, the first three phases of the Cartier Wind Energy Project, which commenced commercial operation in November 2008, November 2007 and November 2006, respectively.

- The Portlands Energy Centre, a 550 MW, combined-cycle natural gas generation power plant located in Toronto, Ontario is 50 per cent owned by TCPL. The plant went into service in simple-cycle mode, capable of delivering 340 MW of electricity in the summer of 2008 and was fully commissioned in April of 2009. This facility provides power under a 20 year Accelerated Clean Energy Supply contract with the Ontario Power Authority.

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

- Oakville Generating Station, a proposed 900 MW natural gas fired combined cycle plant in Oakville, Ontario. TCPL was awarded a 20-year clean energy supply contract to build, own and operate the Oakville Generating Station in September 2009. TCPL expects to invest approximately $1.2 billion in the project which is scheduled to be in service in first quarter 2014.

- The Cartier Wind Energy Project consists of five wind projects in the Gaspé region of Québec contracted by Hydro-Québec Distribution representing a total of 590 MW when all five wind projects are complete. Three of the wind farms are constructed and in service as noted above, and two are currently under construction. The two remaining projects are expected to be placed in service at the end of 2011 and 2012, respectively and have a generating capacity of 270 MW, subject to the necessary approvals. Cartier Wind is 62 per cent owned by TCPL. All of the power produced by Cartier Wind Energy Project is sold to Hydro-Québec Distribution under a 20-year power purchase agreement. In fourth quarter 2009, the proposed 150 MW Les Méchins wind farm project was cancelled due to unavailability of cost-effective wind turbines and difficulty reaching acceptable agreements with private landowners. This decision has no impact on the other Cartier Wind Energy projects.

- A 683 MW natural gas-fired power plant near the town of Halton Hills, Ontario is under construction and is expected to be placed in service in the third quarter of 2010. All of the power produced by the facility is contracted to be sold to the Ontario Power Authority under a 20-year clean energy supply contract.

- The Coolidge generating station is a simple-cycle, natural gas-fired peaking power generation station under development in Coolidge, Arizona. Based on optimal operating conditions, TCPL expects an electrical output of approximately 575 MW from this facility, designed to provide a quick response to peak power demands. The project has received its required permits, construction commenced in August 2009 and the project is expected to be placed in service in second quarter 2011. The power output will be supplied to the Phoenix, Arizona based Salt River Project Agricultural Improvement and Power District under a 20-year power purchase contract.

- The 132 MW Kibby wind power project is under construction and is planned to include 44 turbines located in Kibby and Skinner townships in Maine. Construction began in July 2008 and commissioning of the first phase occurred in October 2009 with half the turbines operational and a generating capacity of 66 MW, and the second phase which consists of the remaining 22 turbines is expected to go into service in 2010 with a generating capacity of 66 MW.

Further information about TCPL s energy holdings and significant developments and opportunities relating to energy can be found in the MD&A under the headings Energy , Energy Highlights , Energy Financial Analysis , and Energy Opportunities and Developments .

GENERAL

Employees

At Year End, TCPL had approximately 4,165 full time active employees, substantially all of whom were employed in Canada and the U.S., as set forth in the following table.

Western Canada (excluding Calgary)		444
Calgary		1,832
Eastern Canada		258
U.S. West Coast		150
U.S. Mid West		476
U.S. Northeast		408
U.S. Southeast/Gulf Coast		201
Houston		387
Mexico and South America		9
	Total	4,165

Social and Environmental Policies

Health, safety and environment (*HS&E*) are top priorities in all of TCPL s operations and activities in these areas are guided by the Company s HS&E Commitment Statement (the *Commitment Statement*). The Commitment Statement outlines guiding principles for a safe and healthy environment for TCPL s employees, contractors and the public, and for TCPL s commitment to protect the environment. All employees are held responsible and accountable for HS&E performance. TCPL is committed to being an industry leader in conducting its business so that it meets or exceeds all applicable laws and regulations, and minimizes risk to people and the environment. TCPL is committed to tracking and improving its HS&E performance, and to promoting safety on and off the job, in the belief that all occupational injuries and illnesses are preventable. TCPL endeavors to do business with companies and contractors that share its perspective on HS&E performance, and to influence them to improve their collective performance. TCPL is committed to respecting the diverse environments and cultures in which it operates, and to supporting open communication with the public, policy makers, scientists and public interest groups.

TCPL is committed to ensuring compliance with its internal policies and legislated requirements. The HS&E Committee of TCPL s board of directors (the *Board*) monitors compliance with the Company s HS&E corporate policy through regular reporting. TCPL s HS&E management system is modeled on the International Organization for Standardization s (*ISO*) standard for environmental management systems, ISO 14001, and focuses resources on the areas of significant risk to the organization s HS&E business activities. Management is informed regularly of all important HS&E operational issues and initiatives through formal reporting processes. TCPL s HS&E management system and performance are assessed by an independent outside firm every three years. The most recent assessment occurred in December 2009 and did not identify any material issues. The HS&E management system also is subject to ongoing internal review to ensure that it remains effective as circumstances change.

In 2009, employee and contractor health and safety performance continued to be a top priority. TCPL s objective is a health and safety performance consistent with top quartile companies in its sectors. Overall, the safety frequency rates in 2009 continued to be better than most industry benchmarks.

The safety and integrity of TCPL s existing and newly developed energy infrastructure also continued to be top priorities. All new assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are not brought into service until all necessary requirements are satisfied. The Company expects to spend approximately $181 million in 2010 for pipeline integrity on its wholly owned pipelines, which is $10 million higher than in 2009 primarily due to increased levels of in-line pipeline inspection on all systems. Under the approved regulatory models in Canada, pipeline integrity expenditures on NEB regulated pipelines are treated on a flow-through basis and, as a result, have no impact on TCPL s earnings. Under the Keystone Oil Pipeline contracts, pipeline integrity expenditures are recovered through the tolling mechanism and, as a result, have no impact on TCPL s earnings. Expenditures for the GTN System may also be recovered through a cost recovery mechanism in its rates. TCPL s pipeline safety record in 2009 continued to be above industry benchmarks. TCPL experienced three pipeline breaks in 2009. The first occurred in a remote part of northern Alberta. The other two occurred in rural parts of northern Ontario. The breaks resulted in minimal impact with no injuries and only minor property damage in one of the incidents. All three incidents were subject to a Level 3 investigation by the Transportation Safety Board of Canada. Spending associated with public safety on the Energy assets is focused primarily on TCPL s hydro dams and associated equipment, and is consistent with previous years.

Environmental Protection

TCPL s facilities are subject to various federal, provincial, state and local statutes and regulations regarding environmental quality and pollution control. TCPL has ongoing inspection programs designed to keep all of its facilities in compliance with environmental requirements and TCPL is confident that its systems are in material compliance with the applicable requirements.

In 2009, TCPL conducted environmental risk assessments and remediation work, as well as various retirement, reclamation and restoration activities on its Canadian and U.S. facilities. At December 31, 2009, TCPL had recorded liabilities of approximately $91 million (2008 - $86 million) for remediation obligations and compliance costs associated with greenhouse gas (*GHG*) legislation, including contingencies. The Company believes it has considered all necessary contingencies and established appropriate reserves for environmental liabilities, however, there is the risk that unforeseen matters may arise requiring the Company to set aside additional amounts.

TCPL is not aware of any material outstanding orders, claims or lawsuits against the Company in relation to the release or discharge of any material into the environment or in connection with environmental protection.

North American climate change policy continues to evolve at regional and national levels. In 2009, TCPL owned assets in three Canadian provinces where regulations exist to address industrial GHG emissions. TCPL has put in place procedures to address these regulations.

In Alberta, under the Specified Gas Emitters Regulation, industrial facilities are required to reduce GHG emissions intensities by 12 per cent effective July 2007. TCPL s Alberta-based facilities are subject to this regulation, as are the Sundance and Sheerness coal-fired power facilities with which TCPL has power purchase agreements. As an alternative to reducing emissions intensities, compliance can be achieved through the retirement of offsets or payments to a technology fund at a cost of $15 per tonne of carbon dioxide (*CO2*) emissions in excess of the mandated reduction. A program is in place to manage the compliance costs incurred by these assets as a result of regulation. Compliance costs on the Alberta System are recovered through tolls paid by customers. Recovery of compliance costs at TCPL s power generation facilities in Alberta is dependent ultimately on market prices for electricity. TCPL has estimated and recorded costs of $17 million for 2009. These costs will be finalized when compliance reports are submitted in March 2010.

The hydrocarbon royalty in Québec is collected by the natural gas distributor on behalf of the Québec government through a green fund contribution charge on gas consumed. In 2009, the cost pertaining to the Bécancour facility arising from the hydrocarbon royalty was less than $1 million as a result of an agreement between TransCanada and Hydro-Québec to temporarily suspend the facility s power generation. The cost is expected to increase substantially when the plant returns to service.

British Columbia s carbon tax, which came into effect in mid-2008, applies to CO2 emissions arising from fossil fuel combustion. Compliance costs for fuel combustion at the Company s compressor and meter stations in British Columbia are recovered through tolls paid by customers.

Costs related to the carbon tax in 2009 were $3 million. The cost per tonne of CO_2 was $15 in 2009 and will increase to $20 per tonne and $25 per tonne in 2010 and 2011, respectively.

Northeastern U.S. states that are members of the Regional Greenhouse Gas Initiative (*RGGI*) implemented a CO_2 cap and trade program for electricity generators effective January 1, 2009. Under the RGGI, both the Ravenswood and Ocean State Power generation facilities will be required to submit allowances by December 31, 2011. TCPL participated in the quarterly auctions of allowances for the Ravenswood and Ocean State power generation facilities and incurred related costs of $8 million in 2009. These costs were generally recovered through the power market and the net impact on TCPL was not significant.

RISK FACTORS

Environmental Risk Factors

Environmental risks from TCPL s operating facilities typically include: air emissions, such as nitrogen oxides, particulate matter and greenhouse gases; potential impacts on land, including land reclamation or restoration following construction; the use, storage or release of chemicals or hydrocarbons; the generation, handling and disposal of wastes and hazardous wastes; and water impacts such as uncontrolled water discharge. Environmental controls including physical design, programs, procedures and processes are in place to effectively manage these risks and TCPL believes it has considered all necessary contingencies and established appropriate reserves for environmental liabilities. However, there is the risk that unforeseen matters may arise requiring TCPL to set aside additional monies.

As mentioned above, TCPL s operations are subject to various environmental laws and regulations that establish compliance and remediation obligations. Compliance obligations can result in significant costs associated with installing and maintaining pollution controls, fines and penalties resulting from any failure to comply, and potential limitations on operations. Remediation obligations can result in significant costs associated with the investigation and remediation of contaminated properties, some of which have been designated as Superfund sites by the United States Environmental Protection Agency under the *Comprehensive Environmental Response, Compensation and Liability Act*, and with damage claims arising out of the contamination of properties. It is not possible for TCPL to estimate the amount and timing of all future expenditures related to environmental matters due to:

- uncertainties in estimating pollution control and clean up costs, including at sites where only preliminary site investigation or agreements have been completed;
- the potential discovery of new sites or additional information at existing sites;
- the uncertainty in quantifying liability under environmental laws that impose joint and several liability on all potentially responsible parties;
- the evolving nature of environmental laws and regulations, including the interpretation and enforcement thereof; and
- the potential for litigation on existing or discontinued assets.

In addition to those climate change policies already in force and which are described above under the heading Environmental Protection , there are also several federal (Canada and U.S.), regional and provincial initiatives currently in development. While recent political and economic events may significantly affect the scope and timing of new measures that are put in place, TCPL anticipates that most of the Company s facilities in Canada and the United States are or will be captured under federal and/or regional climate change regulations to manage industrial GHG emissions. Certain initiatives are outlined below.

The Canadian government has continued to express interest in pursuing a harmonized continental climate change strategy. In January 2010, Environment Canada listed a revised target to the United Nations Framework Convention on Climate Change as part of its submission for the Copenhagen Accord. The submitted target represents a 17 per cent GHG emissions reduction by 2020 relative to 2005 levels. The submission states that Canada will align with the final economy-wide emissions targets of the United States in enacted legislation. TCPL expects that pipeline and power generation facility emissions will be subject to the reduction targets for industrial emitters.

Climate change is a strategic issue for the United States government and federal policy to manage domestic GHG emissions continues to be a priority. The Environmental Protection Agency has released an endangerment finding regarding GHG emissions under the Clean Air Act. This finding was to determine whether the six types of GHGs in the atmosphere threaten the health and welfare of current and future generations. The United States House passed a climate bill in June and the Senate is deliberating on a series of climate bills.

At a regional level, TCPL has assets located in provinces where members of the Western Climate Initiative (WCI) have drafted regulations that apply to industrial GHG emitters. The Canadian WCI members include B.C., Manitoba, Ontario and Québec. The draft climate change strategies are expected to come into effect in 2012 and are expected to affect TCPL s pipeline and power facilities. The details of how these provincial programs will align with the Canadian government s climate change policies remain uncertain.

Seven western U.S. states, along with the four Canadian provinces discussed above, are focused on the implementation of a cap and trade program under the WCI. Members of the WCI have set a GHG emission target of 15 per cent below 2005 levels by 2020. California, a WCI founding member, has released draft cap and trade regulations that, if enacted, are anticipated to have an impact on the Company s pipeline assets in the state. The financial implications are not expected to be material. Under the current form of draft regulations in Washington and Oregon it is expected that there will not be a significant cost of compliance in these states. TCPL will continue to monitor these developments.

Participants in the Midwestern Greenhouse Gas Reduction Accord, which involves six U.S. states and the province of Manitoba, are developing a regional strategy for reducing members GHG emissions that will include a multi-sector cap and trade mechanism. Draft recommendations have been released but as yet not formally endorsed by participant states and Manitoba.

TCPL monitors climate change policy developments and, when warranted, participates in policy discussions in jurisdictions where the Company has operations. The Company is also continuing its programs to manage GHG emissions from its facilities and to evaluate new processes and technologies that result in improved efficiencies and lower GHG emission rates.

Other Risk Factors

A discussion of the Company s risk factors can be found in the MD&A under the headings Pipelines - Opportunities and Developments , Pipelines - Business Risks , Pipelines Outlook , Energy - Opportunities and Developments , Energy - Business Risks , Energy Outlook and Management and Financial Instruments .

DIVIDENDS

All of TCPL s common shares are held by TransCanada and as a result, any dividends declared by TCPL on its common shares are paid to TransCanada. TCPL s Board has not adopted a formal dividend policy. The Board reviews the financial performance of TCPL quarterly and makes a determination of the appropriate level of dividends to be declared in the following quarter. 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 and preferred shareholders 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 and preferred shares. In the opinion of TCPL management, such provisions do not currently restrict or alter TCPL s ability to declare or pay dividends.

The holders of the first preferred shares, Series U are entitled to receive as and when declared by the Board, fixed cumulative preferential cash dividends at an annual rate of $2.80 per share, payable quarterly. The dividends declared per share during the past three completed financial years are set forth in the following table.

	2009	2008	2007
Dividends declared on common shares(1)	**$1.62**	$1.49	$1.39
Dividends declared on preferred shares, Series U	**$2.80**	$2.80	$2.80
Dividends declared on preferred shares, Series Y	**$2.80**	$2.80	$2.80

(1) TCPL dividends on its common shares are declared in an amount equal to the aggregate cash dividend paid by TransCanada to its public shareholders. The amounts presented reflect the aggregate amount divided by the total outstanding common shares of TCPL.

DESCRIPTION OF CAPITAL STRUCTURE

Share Capital

TCPL s authorized share capital consists of an unlimited number of common shares, of which 649,552,723 were issued and outstanding at Year End, and an unlimited number of first preferred shares and second preferred shares, issuable in series. There were 4,000,000 Series U and 4,000,000 Series Y first preferred shares issued and outstanding at Year End. The following is a description of the material characteristics of each of these classes of shares.

Common Shares

As the holder of all of TCPL s common shares, TransCanada holds all the voting rights in those common shares.

First Preferred Shares, Series U

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 holders of the first preferred shares, Series U are entitled to receive dividends as set out above under Dividends .

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 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 TCPL in the event of a liquidation, dissolution or winding up of TCPL.

TCPL is entitled to purchase for cancellation, some or all of the first preferred shares, Series U outstanding at the lowest price which such shares are obtainable, in the opinion of the Board, but not exceeding $50.00 per share plus costs of purchase. Furthermore, TCPL may redeem, on or after October 15, 2013, some or all of the first preferred shares, Series U upon payment for each share at $50.00 per share.

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 unless and until TCPL fails to pay, in the aggregate, six quarterly dividends on the first preferred shares, Series U.

The provisions attaching to the first preferred shares as a class may be modified, amended or varied only with the approval of the holders of the first preferred shares as a class. Any such approval 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.

First Preferred Shares, Series Y

The rights, privileges, restrictions and conditions attaching to the first preferred shares, Series Y are substantially identical to those attaching to the first preferred shares, Series U except that the first preferred shares, Series Y are redeemable by TCPL after March 5, 2014.

Debt

The following table sets out the issuances by TCPL of senior unsecured notes, medium term unsecured note debentures and junior subordinated notes with terms to maturity in excess of one year, during the 12 months ended December 31, 2009.

Date Issued	Issue Price per $1,000 Principal Amount of Notes	Aggregate Issue Price
January 9, 2009	US$999.77(1)	US$749,827,500
January 9, 2009	US$991.48(1)	US$1,239,350,000
February 17, 2009	$995.29	$389,116,000
February 17, 2009	$997.17	$299,151,000

(1) These notes were issued under the same prospectus supplement. Notes maturing in 2019 were issued at 99.977% and notes maturing in 2039 were issued at 99.148%.

There are no provisions associated with this debt that entitle debt holders to voting rights. From time to time, TCPL issues commercial paper for terms not exceeding nine months.

CREDIT RATINGS

The following table sets out the credit ratings assigned to those outstanding classes of securities of TCPL which have been rated by DBRS Limited (*DBRS*), Moody s Investors Service, Inc. (*Moody s*) and Standard and Poor s (*S&P*):

	DBRS	**Moody s**	**S&P**
Senior Unsecured Debt			
Debentures	A	A3	A-
Medium-Term Notes	A	A3	A-
Junior Subordinated Notes	BBB (high)	Baa1	BBB
Preferred Shares	Pfd-2 (low)	Baa2	P-2
Commercial Paper	R-1 (low)	-	-
Trend/Rating Outlook	Stable	Stable	Stable

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.

DBRS Limited (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 in the third highest of ten rating categories and indicates satisfactory credit quality. The overall strength and outlook for key liquidity, debt and profitability ratios 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 rating assigned to TCPL s senior unsecured debt is in 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 securities. 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 BBB (high) rating assigned to junior subordinated notes is in the fourth highest of the ten categories for long-term debt. Long-term debt rated BBB is of adequate credit quality. Protection of interest and principal is considered acceptable but there may be other adverse conditions present which reduce the strength of the entity and its rated securities. The Pfd-2 (low) rating assigned to TCPL s and TransCanada s preferred shares is in 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 Investors Service, Inc. (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 A3 rating assigned to TCPL s senior unsecured debt is 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 Baa 1 and Baa2 ratings assigned to TCPL s junior subordinated debt and preferred shares, respectively, are in the fourth highest of nine rating categories for long-term obligations, with the junior subordinated debt ranking slightly higher within the Baa rating category with a modifier of 1 as opposed to the modifier of 2 on the preferred shares. 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- rating assigned to TCPL s senior unsecured debt is in 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 slightly more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rated categories. The BBB and P-2 ratings assigned to TCPL s junior subordinated notes and TCPL s and TransCanada s preferred shares 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 holds all of the common shares of TCPL and these are not listed on a public market. During 2009, 51,536,066 common shares of TCPL were issued to TransCanada as set out in the following table:

Date	Number of TCPL Common Shares	Price per TCPL Common Share	Aggregate Issuance Price

January 30, 2009	2,205,006	$33.56	$74,000,000
April 30, 2009	1,727,575	$30.10	$52,000,000
July 31, 2009	17,973,856	$30.60	$550,000,000
Sept. 23, 2009	29,629,629	$33.75	$1,000,000,000

TransCanada s common shares are listed on the Toronto Stock Exchange (*TSX*) and the New York Stock Exchange (*NYSE*). TransCanada s Series 1 Preferred Shares have been listed for trading on the TSX since September 30, 2009. The following tables set forth the reported monthly high, low, and month-end closing trading prices and monthly trading volumes of the common shares of TransCanada on the TSX and the NYSE and the Series 1 Preferred Shares on the TSX for the period indicated:

Common Shares

	TSX (TRP)				NYSE (TRP)			
Month	**High ($)**	**Low ($)**	**Close ($)**	**Volume Traded**	**High (US$)**	**Low (US$)**	**Close (US$)**	**Volume Traded**
December 2009	36.49	33.51	36.19	28,627,985	34.59	32.15	34.37	6,351,654
November 2009	34.13	31.92	34.13	37,471,954	32.54	29.66	32.27	7,399,434
October 2009	33.95	32.31	33.16	31,079,808	32.90	29.86	30.54	7,941,688
September 2009	34.00	31.81	33.37	39,471,205	31.74	28.88	31.02	6,821,758
August 2009	32.76	30.78	32.60	33,574,588	30.29	28.05	29.68	8,761,058
July 2009	31.47	30.19	30.64	37,841,226	28.77	25.88	28.45	5,345,338
June 2009	34.40	30.25	31.32	60,066,715	30.93	26.17	26.91	9,109,155
May 2009	32.86	29.68	32.38	36,231,746	29.94	24.94	29.74	7,608,353
April 2009	30.76	29.34	29.78	35,458,519	25.63	23.20	24.97	10,426,740
March 2009	32.29	28.86	29.83	53,753,101	26.19	22.24	23.65	15,520,736
February 2009	34.24	29.61	30.90	30,216,886	28.05	20.01	24.06	15,409,226
January 2009	35.00	32.08	32.98	29,712,401	29.01	25.51	26.85	11,211,484

Series 1 Preferred Shares

	TSX (TRP.PR.A)			
Month	**High ($)**	**Low ($)**	**Close ($)**	**Volume Traded**
December 2009	26.20	25.51	26.00	917,214
November 2009	25.90	25.35	25.56	914,033
October 2009	25.50	25.01	25.40	1,866,602
September 2009	25.03	24.91	25.00	896,387

In addition, TCPL s Cumulative Redeemable First Preferred Shares, Series U (the *Series U Preferred Shares*) and Series Y (the *Series Y Preferred Shares*) are listed on the TSX. The following table sets forth the reported monthly high and low trading prices and monthly trading volumes of the Series U Preferred Shares and the Series Y Preferred Shares.

Series U Preferred Shares and Series Y Preferred Shares

	Series U (TCA.PR.X)				Series Y (TCA.PR.Y)			
Month	**High ($)**	**Low ($)**	**Close ($)**	**Volume Traded**	**High ($)**	**Low ($)**	**Close ($)**	**Volume Traded**
December 2009	50.45	49.40	50.45	34,599	49.99	49.26	49.80	32,439
November 2009	49.58	49.11	49.55	29,933	49.60	49.00	49.59	24,082
October 2009	49.70	48.90	49.17	29,957	49.75	49.00	49.15	31,441
September 2009	50.42	49.00	49.19	39,035	49.99	48.8	49.02	60,600
August 2009	50.49	47.01	50.00	47,658	50.49	47.5	49.99	41,895
July 2009	47.50	46.26	47.49	69,091	47.55	46.05	47.55	48,308
June 2009	47.05	46.56	46.56	65,081	47.59	46.26	46.30	37,667
May 2009	47.05	46.52	47.05	51,101	47.50	46.76	47.50	29,011
April 2009	47.25	46.25	47.05	58,459	47.50	46.07	47.00	41,581
March 2009	47.25	46.06	46.25	117,121	48.00	46.00	46.23	58,081
February 2009	47.25	44.79	47.00	53,474	47.50	45.80	47.00	24,332
January 2009	46.50	41.62	45.79	50,212	47.00	41.42	45.44	76,276

DIRECTORS AND OFFICERS

As of February 22, 2010, the directors and officers of TransCanada as a group beneficially owned, or exercised control or direction, directly or indirectly, over an aggregate of 504,537 Common Shares of TransCanada. This constitutes less than one per cent of TransCanada s Common Shares. TransCanada collects this information from its directors and officers but otherwise has no direct knowledge of individual holdings of its securities.

Directors

Set forth below are the names of the thirteen directors who served on the Board at Year End, together with their jurisdictions of residence, all positions and offices held by them with TCPL 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 TCPL. Positions and offices held with TransCanada are also held by such person at TCPL. Each director holds office until the next annual meeting or until his or her successor is earlier elected or appointed.

Name and Place of Residence	**Principal Occupation During the Five Preceding Years**	**Director Since**
Kevin E. Benson(1) DeWinton, Alberta Canada	President and Chief Executive Officer, Laidlaw International, Inc. (transportation services) from June 2003 to October 2007. Director, Emergency Medical Services Corporation.	2005
Derek H. Burney(2), O.C. Ottawa, Ontario Canada	Senior strategic advisor at Ogilvy Renault LLP (law firm), Chair, Canwest Global Communications Corp. (communications) and Chair, International Advisory Board for Garda World Consulting & Investigation, a division of Garda World Security Corporation. Director, Canwest Global Communications Corp. Lead director at Shell Canada Limited (oil and gas) from April 2001 to May 2007.	2005
Wendy K. Dobson Uxbridge, Ontario Canada	Professor, Rotman School of Management and Co-Director, Institute for International Business, University of Toronto. Director, the Toronto-Dominion Bank. Vice Chair of the Canadian Public Accountability Board until February 2010 and Chair of the audit committee of the same organization from 2003 to 2009.	1992
E. Linn Draper Lampasas, Texas United States	Director, Alliance Data Systems Corporation (data processing and services), Lead Director, Alpha Natural Resources, Inc. (mining), Director, NorthWestern Corporation (conducting business as NorthWestern Energy) (oil and gas) and Lead Director of Temple-Inland Inc. (materials).	2005
The Hon. Paule Gauthier, P.C., O.C., O.Q., Q.C. Québec, Québec Canada	Senior Partner, Stein Monast LLP (law firm). Director, Metro Inc., RBC Dexia Investor Services Trust and Royal Bank of Canada. Director, Cossette Inc. until December 23, 2009. Director, Institut Québecois des Hautes Études Internationales, Laval University from 2002 until 2009.	2002
Kerry L. Hawkins Winnipeg, Manitoba Canada	Director, NOVA Chemicals Corporation until July 6, 2009. President, Cargill Limited (agricultural) from September 1982 to December 2005.	1996
S. Barry Jackson Calgary, Alberta Canada	Chair of the Board, TransCanada since April 2005. Director, Nexen Inc. (oil and gas). Director, WestJet Airlines Ltd. Chair of Resolute Energy Inc. (oil and gas) from January 2002 to April 2005 and Chair of Deer Creek Energy Limited (oil and gas) from April 2001 to September 2005.	2002
Paul L. Joskow New York, New York United States	Economist and President of the Alfred P. Sloan Foundation. On leave from his position as Professor of Economics and Management, Massachusetts Institute of Technology (MIT) where he has been on the faculty since 1972. Trustee of Yale University since July 1, 2008 and member of the Board of Overseers of the Boston Symphony Orchestra since September 2005. Director of the MIT Center for Energy and Environmental Policy Research from 1999 to 2007 and Director of National Grid plc from 2000 to 2007. Director of Exelon Corporation (energy) since July 2007. Trustee of Putnam Mutual Funds.	2004
Harold N. Kvisle Calgary, Alberta Canada	President and Chief Executive Officer of TransCanada since May 2003 and TCPL since May 2001. Director, Bank of Montreal and ARC Energy Trust.	2001
John A. MacNaughton(3), C.M. Toronto, Ontario Canada	Chair of the Business Development Bank of Canada and of CNSX Markets Inc. (formerly the Canadian Trading and Quotation System Inc.) (stock exchange). Director, Nortel Networks Corporation and Nortel Networks Limited (the principal operating subsidiary of Nortel Networks Corporation) (technology). Chair of the Independent Nominating Committee of the new Canada Employment Insurance Financing Board since 2008. Founding President and Chief Executive Officer of the Canada Pension Plan Investment Board from 1999 to 2005.	2006

David P. O Brien(4) Calgary, Alberta Canada	Chair, EnCana Corporation (oil and gas) since April 2002 and Chair, Royal Bank of Canada since February 2004. Director, Molson Coors Brewing Company, Enerplus Resources Fund and C.D. Howe Institute. Chancellor, Concordia University and a member of the Science, Technology and Innovation Council of Canada.	2001

Name and Place of Residence	**Principal Occupation During the Five Preceding Years**	**Director Since**
W. Thomas Stephens Greenwood Village, Colorado United States	Chair and Chief Executive Officer of Boise Cascade, LLC from November 2004 to November 30, 2008. Director, Boise Inc.	2007(5)
D. Michael G. Stewart Calgary, Alberta Canada	Director, Canadian Energy Services & Technology Corp., Pengrowth Corporation and Orleans Energy Ltd. Chairman and a trustee of Esprit Energy Trust (oil and gas) from August 2004 to October 2006; and a director of Creststreet Power & Income General Partner Limited, the General Partner of Creststreet Power & Income Fund L.P. (wind power) from December 2003 to February 2006.	2006

(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 U.S. on March 24, 2000.

(2) Canwest Global Communications Corp. (*Canwest*) voluntarily entered into, and successfully obtained an Order from the Ontario Superior Court of Justice (Commercial Division) commencing proceedings under the *Companies Creditors Arrangement Act* on October 6, 2009. Following the filing, Canwest shares were de-listed from trading on the TSX and now trade on the TSX Venture Exchange.

(3) Nortel Networks Limited is the principal operating subsidiary of Nortel Networks Corporation (collectively referred to as *Nortel*). Mr. MacNaughton became a director of Nortel on June 29, 2005. Nortel was subject to a management cease trade order on April 10, 2006 issued by the Ontario Securities Commission (*OSC*) and other provincial securities regulators. The cease trade order related to a delay in filing certain of Nortel s 2005 financial statements. The order was revoked by the OSC on June 8, 2006 and by the other provincial securities regulators very shortly thereafter. On January 14, 2009, Nortel, and certain of Nortel s other Canadian subsidiaries filed for creditor protection under the *Companies Creditors Arrangement Act* (Canada).

(4) Mr. O Brien was a director of Air Canada in April 2003 when Air Canada filed for protection under the *Companies Creditors Arrangement Act* (Canada) and applicable bankruptcy protection statutes in the U.S. Mr. O Brien resigned as a director of Air Canada on November 26, 2003.

(5) Mr. Stephens previously served on the Board from 2000 to 2005.

Board Committees

TCPL has four committees of the Board: the Audit Committee, the Governance Committee, the Health, Safety and Environment Committee and the Human Resources Committee. The voting members of each of these committees, as of Year End, are identified below:

Audit Committee	**Governance Committee**	**Health, Safety & Environment Committee**	**Human Resources Committee**

Chair:	K.E. Benson	Chair:	J.A. MacNaughton	Chair:	E.L. Draper	Chair:	W.T. Stephens
Members:	D.H. Burney	Members:	K.E. Benson	Members:	W.K. Dobson	Members:	W.K. Dobson
	E.L. Draper		D.H. Burney		P. Gauthier		P. Gauthier
	P.L. Joskow		P.L. Joskow		K.L. Hawkins		K.L. Hawkins
	J.A. MacNaughton		D.P. O Brien		W.T. Stephens		D.P. O Brien
	D.M.G. Stewart		D.M.G. Stewart				S.B. Jackson
			S.B. Jackson				

The charters of the Audit Committee, Governance Committee, the Health, Safety & Environment Committee and the Human Resources Committee can be found on TransCanada s website under the Corporate Governance - Board Committees page located at www.transcanada.com. Information about the audit committee can be found in this AIF under the heading Audit Committee .

Further information about the Board committees and corporate governance can also be found on TransCanada s website.

Officers

All of the executive officers and corporate officers of TCPL reside in Calgary, Alberta, Canada. Current positions and offices held with TCPL are also held by such person at TransCanada. As of the date hereof, the officers of TCPL, their present positions within TCPL 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	President and Chief Executive Officer
Russell K. Girling	Chief Operating Officer and President, Pipelines	Prior to July 2009, President, Pipelines. Prior to June 2006, Executive Vice-President, Corporate Development and Chief Financial Officer
Gregory A. Lohnes	Executive Vice-President and Chief Financial Officer	Prior to June 2006, President and Chief Executive Officer of Great Lakes Gas Transmission Company
Dennis J. McConaghy	Executive Vice-President, Pipeline Strategy and Development	Prior to June 2006, Executive Vice-President, Gas Development
Sean McMaster	Executive Vice-President, Corporate and General Counsel and Chief Compliance Officer	Prior to October 2006, General Counsel and Chief Compliance Officer. Prior thereto, General Counsel since June 2006. Prior to June 2006, Vice-President, Transactions, Power Division, TCPL and concurrently, prior to August 2005, President TransCanada Power Services Ltd., general partner of TransCanada Power, L.P.
Alexander J. Pourbaix	President, Energy and Executive Vice-President, Corporate Development	Prior to July 2009, President, Energy. Prior to June 2006, Executive Vice-President, Power
Sarah E. Raiss	Executive Vice-President, Corporate Services	Executive Vice-President, Corporate Services
Donald M. Wishart	Executive Vice-President, Operations and Major Projects	Prior to July 2009, Executive Vice-President, Operations and Engineering

Corporate Officers

Name	Present Position Held	Principal Occupation During the Five Preceding Years
Ronald L. Cook	Vice-President, Taxation	Vice-President, Taxation
Donald J. DeGrandis	Corporate Secretary	Prior to June 2006, Associate General Counsel, Corporate
Garry E. Lamb	Vice-President, Risk Management	Vice-President, Risk Management
Donald R. Marchand	Vice-President, Finance and Treasurer	Vice-President, Finance and Treasurer
G. Glenn Menuz	Vice President and Controller	Prior to June 2006, Assistant Controller

Conflicts of Interest

Directors and officers of TCPL and its subsidiaries are required to disclose the existence of existing or potential conflicts in accordance with TCPL policies governing directors and officers and in accordance with the *Canada Business Corporations Act*. Although some of the directors sit on boards or may be otherwise associated with companies that ship natural gas on TCPL s pipeline systems, TCPL, as a common carrier in Canada, cannot, under its tariff, deny transportation service to a credit worthy shipper. Further, due to the specialized nature of the industry, TCPL believes that it is important for its Board to be composed of qualified and knowledgeable directors, so some of them must come from the oil and gas producer and shipper community; the Governance Committee monitors relationships among directors to ensure that business associations do not affect the Board s performance. In a circumstance where a director declares an interest in any material contract or material transaction being considered at a meeting, the director generally absents himself or herself from the meeting during the consideration of the matter, and does not vote on the matter.

CORPORATE GOVERNANCE

The Board and the members of TCPL s management are committed to the highest standards of corporate governance. TCPL s corporate governance practices comply with the governance rules of the Canadian Securities Administrators (*CSA*), those of the NYSE and of the SEC applicable to foreign issuers, and those mandated by the U.S. *Sarbanes Oxley Act of 2002*. As a non-U.S. company, TCPL is not required to comply with most of the NYSE corporate governance listing standards; however, except as summarized on our website at www.transcanada.com, the governance practices followed are in compliance with the NYSE standards for U.S. companies in all significant respects. TCPL is in compliance with the CSA s National Instrument 52-110 pertaining to audit committees; National Policy 58-201, Corporate Governance Guidelines; and National Instrument 58-101, Disclosure of Corporate Governance Practices. Further information about TCPL s corporate governance can be found on TransCanada s website at www.transcanada.com under the heading Corporate Governance or at Schedule B to this AIF.

AUDIT COMMITTEE

TCPL has an Audit Committee which is responsible for assisting the Board in overseeing the integrity of TCPL s financial statements and compliance with legal and regulatory requirements and in ensuring the independence and performance of TCPL s internal and external auditors. The Charter of the Audit Committee can be found in Schedule C of this AIF and on TransCanada s website under the Corporate Governance - Board Committees page, at www.transcanada.com.

Relevant Education and Experience of Members

The members of the Audit Committee at Year End were Kevin E. Benson (Chair), Derek H. Burney, E. Linn Draper, Paul L. Joskow, John A. MacNaughton and D. Michael G. Stewart.

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. Benson 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 TCPL, 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:

Kevin E. Benson

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 was the President and Chief Executive Officer of Laidlaw International, Inc. until October, 2007. 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 and on the audit committees of certain of those boards.

Derek H. Burney

Mr. Burney earned a Bachelor of Arts (Honours) and Master of Arts from Queen s University. He is currently a senior strategic advisor at Ogilvy Renault LLP. Mr. Burney previously served as President and Chief Executive Officer of CAE Inc. and as Chairman and Chief Executive

Officer of Bell Canada International Inc. Mr. Burney was the lead director at Shell Canada Limited until May 2007 and is the Chairman of Canwest Global Communications Corp. He has served on one other organization s audit committee.

E. Linn Draper

Dr. Draper holds a Bachelor of Science in Chemical Engineering from Rice University and a Ph.D. in Nuclear Science and Engineering from Cornell University. Dr. Draper was Chairman, President and Chief Executive Officer of American Electric Power Co., Inc. until 2004. He previously served as Chairman, President and Chief Executive Officer of Gulf States Utilities Company. Dr. Draper has served and continues to serve on several other public company boards.

Paul L. Joskow

Mr. Joskow earned a Bachelor of Arts with Distinction in Economics from Cornell University, a Masters of Philosophy in Economics from Yale University, and a Ph.D. in Economics from Yale University. He is currently the President of the Alfred P. Sloan Foundation and on leave from his position as a Professor of Economics and Management, MIT. He has served on the boards of several public companies and other organizations and on the audit committees of certain of those boards.

John A. MacNaughton

Mr. MacNaughton earned a Bachelor of Arts in Economics from the University of Western Ontario. Mr. MacNaughton is currently the Chairman of the Business Development Bank of Canada and of CNSX Markets Inc. (formerly Canadian Trading and Quotation System Inc.) In prior years, he has held several executive positions including founding President and Chief Executive Officer of the Canadian Pension Plan Investment Board and President of Nesbitt Burns Inc. He has served on the audit committee of other public companies.

D. Michael G. Stewart

Mr. Stewart earned a Bachelor of Science (Honours) in Geological Science from Queen s University. Mr. Stewart has served and continues to serve on the boards of several public companies and other organizations and on the audit committees of certain of those boards. He has been active in the Canadian energy industry for over 36 years.

Pre-Approval Policies and Procedures

TCPL 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 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 to arise on an engagement, the Audit Committee Chair must pre-approve the assignment.

To date, TCPL has not approved any non-audit services on the basis of the de-minimus 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 following table provides information about the fees paid by the Company to KPMG LLP, the external auditor of the TransCanada group of companies, for professional services rendered for the 2009 and 2008 fiscal years.

Fee Category	**2009**	**2008**	**Description of Fee Category**
	(millions of dollars)		
Audit Fees	**$7.14**	**$6.69**	Aggregate fees for audit services rendered for the audit of the annual consolidated 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	**$0.15**	**$0.08**	Aggregate fees for assurance and related services that are reasonably related to performance of the audit or review of the consolidated 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 certain pension plans.
Tax Fees	**$1.13**	**$0.14**	Aggregate fees rendered for tax planning and tax compliance advice. The nature of these services consisted of domestic and international tax planning advice and tax compliance matters including the review of income tax returns and other tax filings.
All Other Fees	**$0.43**	**$0.37**	Aggregate fees for products and services other than those reported elsewhere in this table. The nature of these services consisted primarily of advice and training primarily related to compliance with IFRS.
Total	**$8.85**	**$7.28**	

INDEBTEDNESS OF DIRECTORS AND EXECUTIVE OFFICERS

As at the date hereof and since the beginning of the most recently completed financial year, no executive officer, director, or former executive officer or director of TCPL or its subsidiaries, no proposed nominee for election as a director of TCPL, or any associate of any such director, executive officer or proposed nominee has been indebted to TCPL or any of its subsidiaries. There is no indebtedness of any such person to another entity that is the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by TCPL or any of its subsidiaries.

SECURITIES OWNED BY DIRECTORS

The following table sets out the number of each class of securities of TCPL or any of its affiliates beneficially owned, directly or indirectly, or over which control or direction is exercised and the number of deferred share units credited to each director, as of February 22, 2010.

Director	**TransCanada Common Shares(1)**	**Deferred Share Units(2)**
K. Benson	13,000	27,230
D. Burney	4,227	24,904
W. Dobson	6,000	40,904
E.L. Draper	0	27,602
P. Gauthier	2,000	35,405
K. Hawkins(3)	5,013	54,276
S.B. Jackson	39,000	50,101
P.L. Joskow	5,000	19,833
H. Kvisle(4)(5)	1,111,899	N/A
J. MacNaughton	50,000	20,339
D. O Brien	51,177	36,649
W. T. Stephens	1,470	8,327
D.M.G. Stewart(6)	11,402	11,003

(1) The information as to shares beneficially owned or over which control or direction is exercised, not being within the knowledge of TCPL, has been furnished by each of the nominees. Except as indicated in these notes, the nominees have sole voting and dispositive power with respect to the securities listed above. As to each class of shares of TCPL, its subsidiaries and affiliates, the percentage of outstanding shares beneficially owned by any one director or nominee or by all directors and officers of TCPL as a group does not exceed 1% of the class outstanding.

(2) The value of a deferred share unit is tied to the value of TransCanada s common shares. A deferred share unit is a bookkeeping entry, equivalent to the value of a TransCanada common share, and does not entitle the holder to voting or other shareholder rights, other than the accrual of additional deferred share units for the value of dividends. A director cannot redeem deferred share units until the director ceases to be a member of the Board. Canadian directors can then redeem their units for cash or shares while U.S. directors can only redeem their units for cash.

(3) The shares listed include 3,500 shares held by Mr. Hawkins wife.

(4) Securities owned, controlled or directed include common shares that Mr. Kvisle has a right to acquire through the exercise of stock options that are vested under the Stock Option Plan, which is described elsewhere in this AIF. Directors as such do not participate in the Stock Option Plan. Mr. Kvisle, as an employee of TCPL, has the right to acquire 1,025,847 Common Shares under vested stock options, which amount is included in this column.

(5) Mr. Kvisle is an employee of TCPL and participates is the ESU program; he does not participate in the DSU program.

(6) The shares listed include 518 shares held by Mr. Stewart s wife.

COMPENSATION OF DIRECTORS

Unless as otherwise defined in the following sections, all capitalized terms used from herein shall have the same meaning ascribed to them in TransCanada s Management Proxy Circular (the *Proxy Circular*), dated February 22, 2010.

TransCanada s directors also serve as directors of TCPL. An aggregate fee is paid for serving on the Boards of TransCanada and TCPL. Since TransCanada does not hold any assets directly, other than the common shares of TCPL and receivables from certain of TransCanada s subsidiaries, all directors costs are assumed by TCPL according to a management services agreement between the two companies. The meetings of the boards and committees of TransCanada and TCPL run concurrently.

TCPL s director compensation practices are designed to reflect the size and complexity of TCPL and to reinforce the emphasis we place on shareholder value by linking a significant portion of directors compensation to the value of common shares. As a result, directors compensation consists of annual retainers and meeting fees paid in cash and in equity-based compensation known as deferred share units (*DSUs*).

The Governance Committee assesses the market competitiveness of our director compensation on an annual basis against publicly traded autonomous Canadian companies in the Comparator Group (as defined under the heading Compensation Discussion and Analysis) and a general industry sample of Canadian companies, using an analysis provided by an outside consultant. Its goal is to provide total compensation to directors that is generally targeted at the median of our peers in both level and form in order to attract and retain qualified individuals. This goal is reflected in the current compensation paid to directors. The compensation philosophy for directors compensation is different than that for the executive officers discussed under the heading Compensation Discussion and Analysis in that it is not directly based on the performance of the Company.

DIRECTOR COMPENSATION TABLE

The following table sets forth the total compensation paid by TCPL to directors in 2009.

Name (a)	Fees Earned(1) ($) (b)	Share-based Awards(2) ($) (c)	All Other Compensation ($) (d)	Total ($) (e)
K.E. Benson	126,891	77,134	-	204,025
D.H. Burney	113,500	72,000	-	185,500
W.K. Dobson	113,843	72,000	-	185,843
E.L. Draper	122,000	72,000	-	194,000
P. Gauthier	115,000	72,000	-	187,000
K.L. Hawkins	118,000	72,000	-	190,000
S.B. Jackson(3)	213,000	180,000	29,007	393,000
P.L. Joskow	109,000	72,000	-	181,000
J.A. MacNaughton	120,157	72,000	-	192,157
D.P. O Brien	109,000	72,000	-	181,000
W.T. Stephens	123,500	72,000	-	195,500
D.M.G. Stewart	112,000	72,000	-	184,000

(1) Includes all annual Board and committee retainers and meeting fees paid in cash.

(2) These amounts reflect the portion of the Board retainer ($72,000) and the Board Chair retainer ($180,000) that is required to be paid in DSUs. Each director may choose to receive all or some of the balance of their fees in DSUs and in such event, these amounts have been included in this column, Fees Earned . Directors may also be granted share-based awards in the form of DSUs as additional directors compensation under the DSU Plan. There were no DSUs awarded to directors in separate grants in 2009.

(3) The Chair was reimbursed for certain office and other expenses of approximately $29,007 in 2009.

RETAINERS AND FEES PAID TO DIRECTORS

Annual board and committee retainers are paid to each director who is not an employee of TCPL in quarterly installments, in arrears, and are pro-rated from the date of the director s appointment to the Board and the relevant committees. Each committee chair is entitled to claim a per diem for time spent on committee activities outside of the committee meetings. TCPL pays a travel fee of $1,500 per meeting for which round trip travel time exceeds three hours, and reimburses the directors for out-of-pocket expenses incurred in attending such meetings. The retainers and fees paid to non-employee directors in 2009 are set forth in the following table. Directors who are U.S. residents are paid the same amounts as outlined below in U.S. dollars. There were no changes to directors fees in 2009.

Board Chair retainer	$360,000 per annum ($180,000 in cash + $180,000 value of DSUs)(1)(2)
Board Chair meeting fee	$3,000 per Chaired Board meeting(1)
Board retainer	$142,000 per annum ($70,000 cash + $72,000 value of DSUs)(2)
Committee retainer	$4,500 per annum
Committee Chair retainer	$5,500 per annum
Board and Committee meeting fee	$1,500 per meeting
Committee Chair meeting fee	$1,500 per meeting

(1) The Chair is paid only the Board Chair retainer fee, the Board Chair meeting fee and the travel fee. The Chair does not receive any other retainers or meeting fees.

(2) The $180,000 portion of the Board Chair retainer paid in DSUs and the $72,000 portion of the Board retainer paid in DSUs are equal to an aggregate of 5,537 DSUs and 2,214 DSUs, respectively, which were granted quarterly, in arrears, based on the closing price of the common shares of TransCanada at the end of each quarter in 2009 of $29.83, $31.32, $33.37 and $36.19, respectively.

Directors are entitled to direct all or a portion of their cash retainers, meeting fees and travel fees to be paid in DSUs. In 2009, Mr. Benson, Mr. Burney, Dr. Draper and Mr. Hawkins directed all of their retainers, meeting fees and travel fees to be paid in DSUs. Ms. Gauthier directed her Committee retainers, Committee meeting fees and travel fees to be paid in DSUs. Mr. MacNaughton directed his Board and Committee retainers, Board meeting fees and travel fees to be paid in DSUs. Mr. O Brien directed his Board retainers to be paid in DSUs. In addition, Mr. Jackson directed the cash portion of his Chair retainer as well as his Board

Chair meeting fee and travel fees to be paid in DSUs. For further information on the plan for DSUs, see the description under the heading Share Unit Plan for Non-Employee Directors below.

2009 Retainers and Fees

The following table sets out the total fees paid in cash and the value of the DSUs awarded or credited for each non-employee director in 2009 as at the date of the grant, unless otherwise stated. Mr. Kvisle, as an employee of TCPL, receives no cash fees or DSUs as a director.

Name	Board Retainer ($)	Committee Retainer ($)	Committee Chair Retainer ($)	Board Meeting Fee ($)	Committee Meeting Fee(1) ($)	Travel Fee ($)	Strategic Planning Sessions ($)	Total Fees Paid in Cash ($)	Total Value of DSUs Credited(2) ($)	Total Cash & Value of DSUs Credited(3) ($)
K.E. Benson(4)	152,125	7,813	5,892	14,524	17,281	4,890	1,500	0	204,025	204,025
D.H. Burney	142,000	9,000	N/A	12,000	13,500	7,500	1,500	0	185,500	185,500
W.K. Dobson(5)	142,000	9,000	1,843	12,000	15,000	4,500	1,500	113,843	72,000	185,843
E.L. Draper(6)(7)	142,000	9,000	5,500	10,500	16,500	9,000	1,500	0	194,000	194,000
P. Gauthier(8)	142,000	9,000	N/A	13,500	13,500	7,500	1,500	85,000	102,000	187,000
K.L. Hawkins(9)	142,000	9,000	N/A	13,500	13,500	10,500	1,500	0	190,000	190,000
S.B. Jackson(10)	360,000	N/A	N/A	27,000	N/A	3,000	3,000	0	393,000	393,000
P.L. Joskow(6)	142,000	9,000	N/A	10,500	10,500	7,500	1,500	109,000	72,000	181,000
J.A. MacNaughton(5)	142,000	9,000	3,657	13,500	15,000	7,500	1,500	15,000	177,157	192,157
D.P. O Brien	142,000	9,000	N/A	13,500	12,000	3,000	1,500	39,000	142,000	181,000
W.T. Stephens(6)	142,000	9,000	5,500	12,000	16,500	9,000	1,500	123,500	72,000	195,500
D.M.G. Stewart(11)	142,000	9,000	N/A	13,500	15,000	3,000	1,500	112,000	72,000	184,000

(1) Amounts shown represent $1,500 per meeting attended paid to each committee member, including the committee chair, plus $1,500 per meeting attended and chaired paid to committee chairs.

(2) Amounts shown include the minimum required amount of Board retainers paid in DSUs ($180,000 value of DSUs for the Chair, $72,000 value of DSUs for other Board members) plus the value of the retainers, meeting fees and travel fees elected to be received in DSUs.

(3) Fees are aggregate amounts respecting duties performed on both TransCanada and TCPL Boards.

(4) Mr. Benson became a member of the Governance Committee on April 30, 2009. He was paid a pro-rated committee retainer reflecting this new membership for the second quarter. As of April 15, 2009, Mr. Benson relocated to Canada from the U.S.; for the period January 1 to April 14, 2009, Mr. Benson s fees and retainers were paid in U.S. dollars and as of April 15, 2009 his fees and retainers were paid in Canadian dollars. Any retainers and fees that were originally paid to Mr. Benson in U.S. dollars prior to April 15, have been converted to Canadian dollars and are included in the above amounts.

(5) On April 30, 2009, Dr. Dobson ceased to be the Chair of the Governance Committee when Mr. MacNaughton became Chair and, as a result, their committee retainers have been pro-rated accordingly. On April 30, 2009, Dr. Dobson became a member of the Health, Safety and Environment Committee.

(6) Directors who are U.S. residents are paid or credited these amounts, including DSU equivalents, in U.S. dollars.

(7) Dr. Draper was a member of the Human Resources Committee until April 30, 2009 when he became a member of the Audit Committee.

(8) Ms. Gauthier was a member of the Audit Committee until April 30, 2009 when she became a member of the Human Resources Committee.

(9) Mr. Hawkins chaired the September 14, 2009 Human Resources Committee meeting in Mr. Stephens absence. He was paid the fee of $1,500 for chairing the meeting.

(10) Mr. Jackson s Board meeting fee includes the fee of $3,000 for each Board meeting he chaired.

(11) Mr. Stewart chaired the February 2, 2009 Audit Committee meeting in Mr. Benson s absence. He was paid the fee of $1,500 for chairing the meeting. Mr. Stewart was a member of the Health, Safety and Environment Committee until April 30, 2009 when he became a member of the Governance Committee.

Minimum Share Ownership Guidelines

The Board believes that directors can more effectively represent the interests of shareholders if they have a significant investment in the common shares of TransCanada, or their economic equivalent. As a result, TCPL requires each director (other than Mr. Kvisle who is subject to executive share ownership guidelines) to acquire and hold a minimum number of common shares, or their economic equivalent, equal in value to five times the director s annual cash portion of their Board retainer. Directors have a maximum of five years to reach this level of ownership. The level of ownership can be achieved by direct purchase of common shares, by participation in the TransCanada Dividend Reinvestment Plan or by directing all or a portion of their retainer fees, attendance fees and travel fees into DSUs as described under the heading Share Unit Plan for Non-Employee Directors below. Should a director s shareholdings fall below the minimum threshold at any time after having met such threshold, the director is expected to ensure he or she re-attains the minimum threshold within a reasonable amount of time as determined and reviewed by the Governance Committee.

As of February 22, 2010, all of the directors have achieved the minimum share ownership requirement other than Mr. Stephens who has until 2012 (five years from the date he became a director) to achieve the minimum share ownership requirement.

Share Unit Plan for Non-Employee Directors

The Share Unit Plan for Non-Employee Directors (the *DSU Plan*) was established in 1998. Pursuant to the DSU Plan, Board members are permitted to elect to receive in DSUs any portion of their retainers and meeting fees (including travel fees) regularly paid in cash. The DSU Plan also allows the Governance Committee in its discretion, to grant units as additional compensation for directors.

Initially the value of a DSU is equal to the market value of a common share at the time the directors are credited with the units. The value of a DSU, when redeemed, is equivalent to the market value of a common share at the time the redemption takes place. In addition, at the time dividends are declared and paid on the common shares, each DSU accrues an amount equal to such dividends, which amount is then reinvested in additional DSUs at a price equal to the then market value of a common share. DSUs cannot be redeemed until the director ceases to be a member of the Board. Canadian directors may redeem DSUs for cash or common shares at their option. U.S. directors may only redeem DSUs for cash.

COMPENSATION DISCUSSION AND ANALYSIS

Information relating to TCPL s executive compensation is provided in Schedule F to this AIF. The information is excerpted from TransCanada s Proxy Circular. Board and committee meetings of TransCanada and TCPL run concurrently. TCPL is the principal operating subsidiary of TransCanada.

Executive officers of TCPL also serve as executive officers of TransCanada. An aggregate remuneration is paid for serving as an executive of TCPL and for service as an executive officer of TransCanada. Since TransCanada does not hold any material assets directly other than the common shares of TCPL and receivables from certain of TransCanada s subsidiaries, all executive employee costs are assumed by TCPL according to a management services agreement between the two companies.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

TCPL and its subsidiaries are subject to various legal proceedings and regulatory actions arising in the normal course of business. While the final outcome of such legal proceedings and regulatory actions cannot be predicted with certainty and there can be no assurance that such matters will be resolved in TCPL s favour, it is the opinion of TCPL s management that the resolution of such proceedings and regulatory actions will not have a material impact on TransCanada s consolidated financial position, results of operations or liquidity.

MATERIAL CONTRACTS

The underwriting agreement between TCPL and Citigroup Global Markets Inc., HSBC Securities (USA) Inc., Deutsche Bank Securities Inc., J.P. Morgan Securities Inc., Mitsubishi UFJ Securities International plc, Mizuho Securities USA Inc., and SG Americas Securities, LLC, as underwriters, dated January 6, 2009 as described in this AIF under the heading General Development of the Business Financing Activities is available on SEDAR at www.sedar.com under TCPL s profile.

TRANSFER AGENT AND REGISTRAR

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

INTEREST OF EXPERTS

TCPL s auditors, KPMG LLP, have confirmed that they are independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

ADDITIONAL INFORMATION

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

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

GLOSSARY

AcSB	Accounting Standards Board
AGIA	*Alaska Gasline Inducement Act*
AIF	Annual Information Form of TransCanada Pipelines Limited dated February 22, 2010
Alaska Pipeline System	A 4.5 Bcf/d natural gas pipeline that would extend 2,737 km (1,700 miles) from a new natural gas treatment plant at Prudhoe Bay, Alaska to Alberta
Alberta System	A natural gas transmission system throughout the province of Alberta
ANR	American Natural Resources Company and ANR Storage Company
ANR System	A natural gas transmission system which extends approximately 17,000 km from producing fields in Louisiana, Oklahoma, Texas and the Gulf of Mexico to markets in Wisconsin, Michigan, Illinois, Ohio and Indiana
ATCO Pipelines	A subsidiary of Canadian Utilities Limited
AUC	Alberta Utilities Commission
Bbl/d	Barrels per day
Bcf	Billion cubic feet
Bécancour	A natural gas-fired cogeneration plant near Trois-Rivières, Québec
Bison	The Bison Pipeline Project, a proposed 302-mile pipeline from the Powder River Basin in Wyoming to the NBPL System
Board	TransCanada s Board of Directors
Broadwater	A proposed offshore LNG facility in Long Island Sound, New York
Bruce A	Bruce Power A L.P.
Bruce B	Bruce Power L.P.
Cacouna	The proposed Cacouna Energy LNG facility in Cacouna, Québec
Calpine	Calpine Corporation
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
Cartier Wind Energy Project	Five wind energy projects contracted by Hydro-Québec Distribution representing a total of 590 MW in the Gaspé region of Québec
Chinook	A proposed 500 Kilovolt high voltage direct current transmission project, originating in Montana and extending 1,600 km to Nevada
CO2	Carbon dioxide
Common Shares	Common shares of TransCanada
Coolidge	Coolidge Generating Station
CSA	Canadian Securities Administrators
DBRS	DBRS Limited
EUB	Alberta Energy and Utilities Board
FEIS	Final Environment Impact Statement
FERC	Federal Energy Regulatory Commission (USA)
Framework	The Regulatory Framework for Air Emissions
Foothills System	A natural gas pipeline system in southeastern B.C., southern Alberta and southwestern Saskatchewan
GHG	Greenhouse gas
GTNC	Gas Transmission Northwest Corporation
GTN System	A natural gas transmission system running from northwestern Idaho, through Washington and Oregon to the California border
Great Lakes	Great Lakes Gas Transmission Limited Partnership
Great Lakes System	A natural gas pipeline system in the north central U.S., roughly parallel to the Canada-U.S. Border
Horn River Project	A proposed 158 km (98 mile) pipeline to connect new shale gas supply in the Horn River basin north of Fort Nelson, B.C., to the Alberta System
IFRS	International Financial Reporting Standards
Iroquois System	A natural gas pipeline system in New York and Connecticut
ISO	International Organization of Standardization
Keystone Canada	TransCanada Keystone Pipeline Limited Partnership
Keystone Oil Pipeline	A 3,456 km (2,147 mile) oil pipeline project currently under construction
Keystone U.S.	TransCanada Keystone Pipeline, LP
LNG	Liquefied Natural Gas
MD&A	TCPL s Management s Discussion and Analysis dated February 22, 2010
MMcf/d	Million cubic feet per day
Moody s	Moody s Investors Service, Inc.
MW	Megawatts
NBPL	Northern Border Pipeline Company
NBPL System	A natural gas transmission system located in the upper Midwestern portion of the U.S.
NEB	National Energy Board
NGTL	NOVA Gas Transmission Limited
North Baja	A natural gas pipeline in southern California
NYSDOS	New York Department of State
NYSE	New York Stock Exchange
Portland System	A natural gas pipeline that runs through Maine and New Hampshire into Massachusetts
Portlands Energy Centre	A natural gas-fired combined-cycle power plant near downtown Toronto, Ontario
PPA	Power Purchase Arrangement
Ravenswood	Ravenswood Generating Station, a natural gas and oil-fired generating located in Queens, New York
Ravenswood Agreement	The membership interest and stock purchase agreement between KeySpan Corporation and TransCanada Facility USA Inc. dated March 31, 2008
RGGI	Regional Greenhouse Gas Initiative
S&P	Standard and Poor s
SEC	United States Securities and Exchange Commission
Series 1 Preferred Shares	Cumulative, redeemable, first preferred shares, series 1, of TransCanada
Sheerness	A power plant consisting of two 390 MW coal-fired thermal powered generating units
Sundance	Two coal fired electrical generating facilities which produce 560 MW and 706 MW, respectively
TCPL	TransCanada PipeLines Limited
TQM	Trans Québec & Maritimes Pipeline Inc.
TransCanada or the Company	TransCanada Corporation
TSX	Toronto Stock Exchange
Tuscarora	Tuscarora Gas Transmission Company
Tuscarora System	A natural gas pipeline that runs from Oregon through northeast California to Reno, Nevada
U.S.	United States
WCI	Western Climate Initiative
Year End	December 31, 2009
Zephyr	A proposed 500 Kilovolt high voltage direct current transmission project, originating in Wyoming and extending 1,760 km to Nevada

HS&E	Health, Safety and Environment

SCHEDULE A

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 (km)	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

DISCLOSURE OF CORPORATE GOVERNANCE PRACTICES

The Board and the members of TCPL s management are committed to the highest standards of corporate governance. TCPL s corporate governance practices comply with the governance rules of the Canadian Securities Administrators (*CSA*), those of the New York Stock Exchange (*NYSE*) and of the U.S. Securities and Exchange Commission (*SEC*) applicable to foreign private issuers, and those mandated by the United States Sarbanes Oxley Act of 2002 (*SOX*). As a non-U.S. company, TCPL is not required to comply with most of the NYSE corporate governance listing standards; however, except as summarized on our website at www.transcanada.com, the governance practices followed are in compliance with the NYSE standards for U.S. companies in all significant respects. TCPL is in compliance with the CSA s National Instrument 52-110 pertaining to audit committees (*Canadian Audit Committee Rules*); National Policy 58-201, Corporate Governance Guidelines; and National Instrument 58-101, Disclosure of Corporate Governance Practices (collectively, the *Canadian Governance Guidelines*). At TCPL, we believe that the principal objective in directing and managing the company s business and affairs is promoting the best interests of TCPL in a manner that will ultimately maximize long-term shareholder value and enhance stakeholder relations. TCPL believes that effective corporate governance improves corporate performance and benefits all shareholders. We believe that honesty and integrity are vital factors in ensuring good corporate governance. The discussion that follows relates primarily to the Canadian Governance Guidelines and highlights various elements of the Company s corporate governance program. It has been approved by the Governance Committee and by the Board.

Board of Directors

The Board believes that, as a matter of policy, there should be a majority of independent directors on TCPL s Board. The Board is charged with making this determination based on the annual review conducted by the Governance Committee. The Board is currently comprised of 13 directors, of whom 12 (92%) were determined by the Board in 2010 to be independent directors. Thirteen nominees are being put forward for election at the Annual and Special Meeting of holders of common shares of TransCanada to be held on April 30, 2010, 12 (92%) of whom are independent. The Board annually determines the independent status of each of its members and each nominee for election, based on a written set of criteria developed in accordance with the definition of independent in the Canadian Audit Committee Rules and the Canadian Governance Guidelines. The independence criteria also conform to the applicable rules of the SEC, the NYSE and those set out under SOX. The Board has determined that none of the nominees for director, with the exception of Mr. Kvisle, have a direct or indirect material relationship with TCPL that could interfere with their ability to act in the best interests of TCPL. Mr. Kvisle, as the President and CEO of TCPL, is not independent.

The Governance Committee reviews, at least annually, the existence of any relationship between each director and TCPL to ensure that the majority of directors are independent of TCPL.

Further, the Board considered whether directors serving on boards of non-profit organizations which receive donations from TCPL pose any potential conflict. The Board determined that such relationships, where they exist, do not interfere with any such director s ability to act in the best interests of TCPL, as all decisions on making donations to non-profit organizations are made by a management committee on which no directors serve. The Board also considered family relationships and possible associations with companies which have relationships with TCPL, in its determination of independence.

Although some of the proposed nominees sit on boards or may be otherwise associated with companies that ship natural gas on TCPL s pipeline systems, TCPL as a common carrier in Canada cannot, under its tariff, deny transportation service to a credit worthy shipper. Further, due to the specialized nature of the industry, TCPL believes that it is important for its Board to be composed of qualified and knowledgeable directors, so some of them must come from the oil and gas producer and shipper community; the Governance Committee monitors relationships among directors to ensure that business associations do not affect the Board s performance. In a circumstance where a director declares an interest in any material contract or material transaction being considered at a meeting, the director will absent himself or herself from the meeting during the consideration of the matter, and does not vote on the matter.

All reporting issuers of which the nominees are presently directors of, are set out in the table in TransCanada s Proxy Circular under the heading Nominees for Election to the Board of Directors under the headings Other Public Board Directorships and Other Public Board Committee Memberships . TCPL believes that due to the specialized nature of the industry, it is important for its Board to be composed of qualified and knowledgeable directors.

In 2009, independent directors of the Board met separately before and after every regularly scheduled and special meeting. There were eight regularly scheduled meetings and one special meeting during 2009. In addition, all of the directors are available to meet with management as required.

Mr. Jackson has served as the non-executive Chair of TCPL since April 30, 2005. He has also acted as chair person for Deer Creek Energy Limited (from 2001 to 2005) and Resolute Energy Inc. (from 2002 to 2005).

Director attendance at Board and committee meetings has been excellent and during 2009, all directors demonstrated a strong commitment to their roles and responsibilities. The overall attendance rate was 96% at Board meetings and an average of 93% at committee meetings. Specific attendance statistics are set out with each director s biography in TransCanada s Proxy Circular under the heading Nominees for Election to the Board of Directors .

Board Mandate

The Board discharges its responsibilities directly and through committees. At regularly scheduled meetings, members of the Board and management discuss a broad range of issues relevant to TCPL s strategy and business interests and the Board is responsible for the approval of TCPL s strategic plan. In addition, the Board receives reports from management on TCPL s operational and financial performance. The Board had eight scheduled meetings in 2009. Unscheduled meetings are held from time to time as required; there was one unscheduled meeting of the Board in 2009. There were also two strategic issue sessions and one full-day strategic planning session of the Board held in 2009.

The Board operates under a written charter while retaining plenary power. Any responsibility not delegated to management or a committee of the Board remains with the Board. The Charter of the Board of Directors addresses Board composition and organization, and the Board s duties and responsibilities for managing the affairs of TCPL and its oversight responsibilities with respect to: management and human resources; strategy and planning; financial and corporate issues; business and risk management; policies and procedures; compliance reporting and corporate communications; and general legal obligations, including the ability to use independent advisors as necessary. The charter is available on TransCanada s website at www.transcanada.com and is attached to TCPL s AIF as Schedule E .

The Board also closely oversees any potential conflicts of interest between the Company and its affiliates including TC PipeLines, LP, a NASDAQ listed master limited partnership.

Charters have been adopted for each of the committees outlining their principal responsibilities. The Board and each committee reviews its charter annually to ensure it is in line with the current developments in corporate governance. The Board and each committee is responsible to update its respective charter. All charters are available on TransCanada s website at www.transcanada.com.

Position Descriptions

The Board has developed written position descriptions for its chair, the chair of each of the Board committees and for the CEO. The responsibilities of each committee chair are set out in each respective committee s Charter. The written position descriptions and the committee charters are available on TransCanada s website at www.transcanada.com.

The Human Resources Committee and the Board annually review and approve the CEO s personal performance objectives and review with him his performance against the previous year s objectives. The Human Resources Committee s compensation discussion and analysis can be found attached to TCPL s AIF at Schedule F under the heading Compensation Discussion and Analysis .

Orientation and Continuing Education

New directors are provided with an orientation and education program that includes a directors manual containing information about the duties and obligations of directors, the business and operations of TCPL, copies of governance charters, copies of past public filings and documents from recent Board meetings. New directors are given additional historical and financial information, a session on corporate strategy, are provided opportunities to visit TCPL s facilities and project sites, and are provided with opportunities for meetings and discussions with the executive leadership team and other directors. New directors also meet with the Vice President, Strategy who provides an overview of the different areas of operation within TCPL and identifies key areas of interest to the individual director. Briefing sessions are also held for new committee members, as appropriate. The directors manual and the director induction and continuing education process are reviewed annually by the Governance Committee. The details of the orientation of each new director are tailored to each director s individual needs and expressed areas of interest.

Examples of past activities and visits include a power trading floor tour and discussions with the Western power group business leaders, a visit to the Bruce Power site in Kincardine, Ontario, a tour of the Fort McMurray oil sands development, a tour of the pipeline operations control room and a tour of the Ravenswood generating station in Queens, New York.

Senior management as well as external experts make presentations to the Board and to its committees periodically on various business related topics and on changes in legal, regulatory and industry requirements. Directors tour certain TCPL operating facilities and project sites on an annual basis. In 2009, directors participated in a site visit of two of ANR Pipeline Company s Gulf of Mexico facilities. Directors also held a summit in Washington, DC in September of 2009 which included distinguished speakers on a variety of topics of interest to TCPL related to its U.S. investments and Canada/U.S. relations. Ongoing director education also includes strategic issues sessions, of which three were held in 2009. Topics for the strategic issues sessions, and locations for site visits are determined by the Governance Committee annually based on current issues and corporate objectives. TCPL encourages continuing education for its directors, periodically suggests programs which may be relevant to the directors and provides funding for director education where appropriate. For further detail regarding director education in 2009, refer to 2009 Director Education in TransCanada s Proxy Circular. All Canadian directors are members of the Canadian Institute of Corporate Directors, which provides many opportunities for director education. In 2008, Audit Committee members received a special tutorial in International Financial Reporting Standards from outside consultants and members of management.

Board Access to Senior Management

Board members have complete access to the Company s management, subject to reasonable advance notice to the Company and reasonable efforts to avoid disruption to the Company s management, business and operations. The Board encourages management to include key managers in Board meetings who can share their expertise on matters before the Board. This also enables the Board to gain exposure to key managers with future potential in the Company.

Ethical Business Conduct

The Board has formally adopted and published a set of Corporate Governance Guidelines, which affirms TCPL s commitment to maintaining a high standard of corporate governance. The guidelines address the structure and composition of the Board and its committees and also provide guidance to both the Board and management in clarifying their respective responsibilities. The Board s strengths include: an independent, non-executive Chair; well informed and experienced directors who ensure that standards exist to promote ethical behaviour throughout TCPL; an effective board size; alignment with shareholders through director share ownership requirements; and annual assessments of Board, committee and individual director effectiveness. TCPL s Corporate Governance Guidelines are available on TransCanada s website at www.transcanada.com.

The Board has also adopted a code of business ethics for directors which incorporates as its basis, principles of good conduct and highly ethical behaviour. TCPL has adopted a code of business ethics for its employees and separate codes applicable to its CEO, Chief Financial Officer and Controller, all of which are certified on an annual basis. Compliance with the Company s various codes is monitored by the Audit Committee and reported to the Board. Any waiver of the codes of business ethics by executive officers or directors must be approved by the Board or appropriate committee and disclosed. There have been no material departures from these codes in 2009. TCPL s codes of business ethics may be viewed on TransCanada s website at www.transcanada.com.

Nomination of Directors

The Governance Committee, which is composed entirely of independent directors, is responsible for proposing new nominees to the Board, which in turn is responsible for identifying suitable candidates for election by the shareholders. The Governance Committee annually reviews the qualifications of persons proposed for election to the Board and submits its recommendations to the Board for consideration. The objective of this review is to maintain the composition of the Board in a way that provides the best mix of skills and experience to guide TCPL s long-term strategy and ongoing business operations. New nominees must have experience in the industries in which TCPL participates or experience in general business management of corporations that are a similar size and scope to TCPL, the ability to devote the time required, and a willingness to serve. The Governance Committee also advises the Board on the criteria for, and determination of, the independence of each director.

The Governance Committee regularly assesses the skill set of current board members against a list of potentially desirable skills and experience to be sought when recruiting new directors to the Board.

The Board has determined that no person shall stand for election or re-election to the Board if he or she attains the age of 70 years on or before the date of the annual meeting held in relation to the election of directors; provided however, that if a director attains the age of 70 before serving a full seven consecutive years on the Board, that director may stand for re-election, upon the recommendation of the Board each year until that director has served a full seven years on the Board.

Further information relating to the Governance Committee can be found attached to TCPL s AIF at Schedule D under the heading Board Committees and Their Charters - Governance Committee .

Compensation

The Governance Committee, which is composed entirely of independent directors, reviews the compensation of the directors on an annual basis, taking into account such matters as time commitment, responsibility, and compensation provided by comparable companies, and makes an annual recommendation to the Board for consideration. Towers Watson provides an annual report on directors compensation paid by comparable companies to facilitate the Governance Committee s review of director compensation. Directors may receive their annual retainer, committee and/or chair fees in the form of cash and/or Deferred Share Units. With the exception of Mr. Kvisle, who follows the Share Ownership Guidelines for executives, Directors must hold a minimum of five times their annual cash retainer fee in common shares or related Deferred Share Units of TransCanada. Directors have a maximum of five years from the time they join the Board to reach this level of share ownership. The value of ownership levels is recalibrated when the annual cash retainer is increased.

The Human Resources Committee, which is composed entirely of independent directors, is accountable on behalf of the Board to determine the compensation for the executive officers of TCPL and to recommend to the Board the remuneration package for the CEO and, for 2010, the Executive Leadership Team which includes all Named Executive Officers. The Human Resources Committee reviews the executive compensation disclosure prior to publicly disclosing this information. The process the Human Resources Committee uses for these determinations can be found attached to TCPL s AIF at Schedule F under the heading Compensation Discussion and Analysis .

Further information relating to the Human Resources Committee can be found attached to TCPL s AIF at Schedule D under the heading Board Committees and Their Charters - Human Resources Committee .

Information relating to compensation consulting services provided by Towers Watson during the 2009 financial year can be found attached to TCPL s AIF at Schedule F under the heading Compensation Discussion and Analysis The Role of the External Compensation Consultant .

Other Board Committees

The Board has the following Committees: Audit; Health, Safety and Environment; Governance; and Human Resources. Details relating to these committees can be found attached to TCPL s AIF at Schedule D under the heading Description of Board Committees and Their Charters .

Assessments

The Governance Committee is responsible for making an annual assessment of the overall performance of the Board, its committees and its individual members, and reporting its findings to the Board. An annual questionnaire and/or in-person interview is utilized as part of this process. The questionnaire is circulated to each of the directors and administered by the Corporate Secretary. In person interviews are conducted by the Chair with each member of the Board individually.

The annual assessment examines the effectiveness of the Board as a whole, and of each committee, and solicits input on areas of potential vulnerability or areas that members believe could be improved or enhanced to ensure the continued effectiveness of the Board and its committees. The annual assessment also includes questions regarding personal and peer individual performance. Each committee also conducts an annual self-assessment.

When utilized, responses from the annual questionnaire are compiled by the Corporate Secretary and provided to the Chair, and responses from the in-person interviews are compiled by the Chair. Results are distributed to directors and discussed at the Board. The annual assessment and individual director s terms of reference are then used in the evaluation of the contribution of individual directors.

Formal interviews with each member of TCPL s executive leadership team are carried out annually by the Chair. The Chair of the Governance Committee also interviews each director annually on his or her assessment of the Chair s performance. Each of these assessments are reported annually to the full Board. The Governance Committee monitors and discusses external assessments of Board governance and regularly monitors the literature on evolving best practice in corporate governance.

Financial Literacy of Directors

The Board has determined that all of the members of its Audit Committee are financially literate. An individual is financially literate if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by TCPL s financial statements.

Majority Voting for Directors

TransCanada has adopted a policy whereby, at any meeting where the number of nominees for election is the same as the number of director positions on the Board, if proxy votes withheld for the election of any particular director are greater than 5% of the votes cast by proxy, a ballot pertaining to the election of each of the directors will be held at that meeting. A director is required to tender his resignation if the director receives more votes withheld than for that director s election when such ballot is held. In the absence of extenuating circumstances, the Board is expected to accept that resignation within 90 days. The Board may fill a vacancy in accordance with TCPL s by-laws and the Canada Business Corporations Act. The policy does not apply in the event of a proxy contest with respect to the election of directors. This policy is part of TCPL s Corporate Governance Guidelines which are published on its website at www.transcanada.com.

SCHEDULE C

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. <u>Roles and Responsibilities</u>

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 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;

(f) 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;

(g) 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;

(h) 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;

(i) 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;

(j) 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;

V. Insight 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;

(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, but at least every five years;

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 the implementation and amendments to policies and program initiatives deemed advisable by management or the Audit Committee with respect to the Company s codes of business ethics and Risk Management and Financial Reporting policies;

(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 partners, employees and former partners and employees of the present and former 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 Financial Aspects of the Company s Pension Plans, specifically:

(a) provide advice to the Human Resources Committee on any proposed changes in the Company s pension plans in respect of any significant effect such changes may have on pension financial matters;

(b) review and consider financial and investment reports and the funded status relating to the Company s pension plans and recommend to the Board on pension contributions;

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

(d) review and approve annually the Statement of Investment Policies and Procedures (SIP&P);

(e) approve the appointment or termination of auditors and investment managers;

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 the policy and guidelines for the Company s hiring of partners, employees and former partners and 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) make suggestions and provide feedback from the Audit Committee to management regarding information that is or should be provided to the Audit Committee;

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

(e) 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 and set and pay the compensation for 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 D

DESCRIPTION OF BOARD COMMITTEES AND THEIR CHARTERS

The Board has four standing committees: the Audit Committee; the Governance Committee; the Health, Safety and Environment Committee; and the Human Resources Committee. The Board does not have an Executive Committee. The Audit, Human Resources and Governance committees are required to be composed entirely of independent directors. The Health, Safety and Environment Committee is required to have a majority of independent directors.

Each of the committees has the authority to retain advisors to assist in the discharge of its respective responsibilities. Each of the committees reviews its respective charter at least annually and, as required, recommends changes to the Governance Committee and to the Board. Each of the committees also reviews its respective performance annually.

Each of the committees has a charter which is published on TransCanada s website at www.transcanada.com.

CHAIR S PARTICIPATION IN COMMITTEES

Mr. S.B. Jackson, the Chair of the Board, is an independent director. The Chair is appointed by the Board and serves in a non-executive capacity. The Board adopted the practice of holding simultaneous meetings of certain committees and, as a result, the Chair is a voting member of the Governance and Human Resources Committees but is not a member of the Audit and Health, Safety and Environment Committees. The simultaneous sitting of certain committees allows more time to be available for each committee to focus on its respective responsibilities.

AUDIT COMMITTEE

Chair: *K.E. Benson*

Members: *D.H. Burney, E.L. Draper, P.L. Joskow, J.A. MacNaughton, D.M.G. Stewart*

This committee is comprised of six independent directors and is mandated to assist the Board in monitoring, among other things, the integrity of the financial statements of TCPL, the compliance by TCPL with legal and regulatory requirements, and the independence and performance of TCPL s internal and external auditors. The committee is also mandated to review and recommend to the Board approval of TCPL s audited annual and unaudited interim consolidated financial statements and related management discussion and analysis, and other corporate disclosure documents including information circulars, the annual information form, all financial statements in prospectuses and other offering memoranda, any financial statements required by regulatory authorities and all prospectuses and documents which may be incorporated by reference into a prospectus, before they are released to the public or filed with the appropriate regulatory authorities. In addition, the committee reviews and recommends to the Board the appointment and compensation of the external auditor, oversees the accounting, financial reporting, control and audit functions, and recommends funding of TCPL s pension plans.

Audit Committee information as required under the Canadian Audit Committee Rules (as defined in Schedule D of TransCanada s Proxy Circular) is contained in TCPL s Annual Information Form for the year ending December 31, 2009 in the section Audit Committee . Audit committee information includes the charter, committee composition, relevant education and experience of each member, reliance on exemptions, financial literacy of each member, committee oversight, pre-approval policies and procedures, and external auditor service fees by category. The Annual Information Form is available on SEDAR at www.sedar.com under TCPL s profile and is published on TransCanada s website at www.transcanada.com.

The committee oversees the operation of an anonymous and confidential toll-free telephone number for employees, contractors and the public to call with respect to perceived accounting irregularities and ethical violations, and has set up a procedure for the receipt, retention, treatment and regular review of any such reported activities. This telephone number is published on TransCanada s website at www.transcanada.com, on its intranet for employees and in the Company s Annual Report to shareholders.

The committee reviews the audit plans of the internal and external auditors and meets with them at the time of each committee meeting, in each case both with and without the presence of management. The committee annually receives and reviews the external auditor s formal written statement of independence delineating all relationships between itself and TCPL and its report on recommendations to management regarding internal controls and procedures, and ensures the rotation of the lead audit partner having primary responsibility for the audit as required by law. The committee pre-approves all audit services and all permitted non-audit services. In addition, the committee discusses with management TCPL s material financial risk exposures and the actions management has taken to monitor and control such exposures, reviews the internal control procedures to oversee their effectiveness, monitors compliance with TCPL s policies and codes of business ethics, and reports on these matters to the Board. The committee reviews and approves the investment objectives and choice of investment managers for the Canadian pension plans and considers and approves any significant changes to those plans relating to financial matters.

There were six meetings of the Audit Committee in 2009.

GOVERNANCE COMMITTEE

Chair: *J.A. MacNaughton*

Members: *K.E. Benson, D.H. Burney, P.L. Joskow, D.P. O Brien, D.M.G. Stewart*

This committee is comprised of six independent directors and is mandated to enhance TCPL s governance through a continuing assessment of TCPL s approach to corporate governance. The committee is mandated to identify qualified individuals to become Board members, to recommend to the Board nominees for election as directors at each annual meeting of shareholders and to annually recommend to the Board placement of directors on committees. The committee annually reviews the independence status of each director in accordance with written criteria in order to provide the Board with guidance for its annual determination of director independence and for the placement of members on committees. The committee also oversees the risk management activities of TCPL. The committee monitors, reviews with management and makes recommendations related to TCPL s risk management programs and policies on an ongoing basis.

The committee reviews and reports to the Board on the performance of individual directors, the Board as a whole and each of the committees, in conjunction with the Chair of the Board, set forth in TransCanada s Disclosure of Corporate Governance Practices , in Schedule B of TCPL s Annual Information Form. The committee also monitors the relationship between management and the Board, and reviews TCPL s structures to ensure that the Board is able to function independently of management. The committee chair, in consultation with directors, annually reviews the performance of the Chair of the Board and reports the results to the Board. The committee is also responsible for an annual review of director compensation, for the administration of the DSU Plan and establishing, reviewing and assessing the minimum share ownership guidelines for directors.

The committee monitors best governance practice and ensures any corporate governance concerns are raised with management. The committee ensures the Company has a best practice orientation package and monitors continuing education for all directors as set forth in more detail in TCPL s Disclosure of Corporate Governance Practices , in Schedule B of TCPL s Annual Information Form. For a summary of the continuing education sessions attended by directors in 2009, refer to the table under the section entitled 2009 Director Education in TransCanada s Proxy Circular. The committee also has responsibility for oversight of the Company s Strategic Planning process.

There were three meetings of the Governance Committee in 2009.

HUMAN RESOURCES COMMITTEE

Chair: *W.T. Stephens*

Members: *W.K. Dobson, P. Gauthier, K.L. Hawkins, D.P. O Brien*

This committee is comprised of five independent directors and is mandated to review the Company s human resources policies and plans, monitor succession planning and to assess the performance of the Chief Executive Officer and other senior executive officers of TCPL against pre-established performance objectives. A report on senior management development and succession is prepared annually for presentation to the Board which the committee reviews on an annual basis. The committee reports to the Board with recommendations on the remuneration package for the senior executive officers of TCPL, including the Chief Operating Officer (*COO*) and the CEO. The committee approves all longer-term compensation including stock options and any major changes to TCPL s company-wide compensation and benefit plans. The committee considers and approves any changes to TCPL s pension plans relating to benefits provided under these plans. The committee is also responsible for the review of the executive share ownership guidelines.

The committee recognizes the importance of maintaining good governance practices for the development and administration of executive compensation and benefit programs, and has instituted processes that enhance the committee s ability to effectively carry out its responsibilities. Examples of processes that the committee uses include:

- holding in-camera sessions without Company management present prior to and following every regularly scheduled committee meeting;
- hiring external consultants and advisors and requiring their attendance at specified committee meetings;
- annually approving a checklist that sets out the timetable of all regularly occurring accountabilities for the committee which provides context for the discussion of related items; and
- using a two-step review process where items are provided for the committee s initial review at a meeting prior to the approval meeting.

There were five meetings of the Human Resources Committee in 2009 (four regularly scheduled and one special meeting).

HEALTH, SAFETY AND ENVIRONMENT COMMITTEE

Chair: *E.L. Draper*

Members: *W.K. Dobson, P. Gauthier, K.L. Hawkins, W.T. Stephens*

This committee is comprised of five independent directors and is mandated to monitor the health, safety, security and environmental practices and procedures of TCPL and its subsidiaries for compliance with applicable legislation, conformity with industry standards and prevention or mitigation of losses. The committee also considers whether the implementation of TCPL s policies related to health, safety, security and environmental matters are effective, including policies and practices to prevent loss or injury to TCPL s employees and its assets, networks or infrastructure from malicious acts, natural disasters or other crisis situations. The committee reviews reports and, when appropriate, makes recommendations to the Board on TCPL s policies and procedures related to health, safety, security and the environment. This committee meets separately with officers of TCPL and its business units who have responsibility for these matters and reports to the Board on such meetings.

There were three meetings of the Health, Safety and Environment Committee in 2009.

SCHEDULE E

CHARTER OF THE BOARD OF DIRECTORS

I. INTRODUCTION

A. The Board s primary responsibility is to foster the long-term success of the Company consistent with the Board s responsibility to act honestly and in good faith with a view to the best interests of the Company.

B. The Board of Directors has plenary power. Any responsibility not delegated to management or a committee of the Board remains with the Board. This Charter is prepared to assist the Board and management in clarifying responsibilities and ensuring effective communication between the Board and management.

II. COMPOSITION AND BOARD ORGANIZATION

A. Nominees for directors are initially considered and recommended by the Governance Committee of the Board, approved by the entire Board and elected annually by the shareholders of the Company.

B. The Board must be comprised of a majority of members who have been determined by the Board to be independent. A member is independent if the member has no direct or indirect relationship which could, in the view of the Board, be reasonably expected to interfere with the exercise of a member s independent judgment.

C. Directors who are not members of management will meet on a regular basis to discuss matters of interest independent of any influence from management.

D. Certain of the responsibilities of the Board referred to herein may be delegated to committees of the Board. The responsibilities of those committees will be as set forth in their Charter, as amended from time to time.

III. DUTIES AND RESPONSIBILITIES

A. Managing the Affairs of the Board

The Board operates by delegating certain of its authorities, including spending authorizations, to management and by reserving certain powers to itself. Certain of the legal obligations of the Board are described in detail in Section IV. Subject to these legal obligations and to the Articles and By-laws of the Company, the Board retains the responsibility for managing its own affairs, including:

i) planning its composition and size;

ii) selecting its Chair;

iii) nominating candidates for election to the Board;

iv) determining independence of Board members;

v) approving committees of the Board and membership of directors thereon;

vi) determining director compensation; and

vii) assessing the effectiveness of the Board, committees and directors in fulfilling their responsibilities.

B. Management and Human Resources

The Board has the responsibility for:

i) the appointment and succession of the Chief Executive Officer (CEO) and monitoring CEO performance, approving CEO compensation and providing advice and counsel to the CEO in the execution of the CEO s duties;

ii) approving a position description for the CEO;

iii) reviewing CEO performance at least annually, against agreed-upon written objectives;

iv) approving decisions relating to senior management, including the:

a) appointment and discharge of officers of the Company and members of the senior executive leadership team;

b) compensation and benefits for members of the senior executive leadership team;

c) acceptance of outside directorships on public companies by senior executive officers (other than not-for-profit organizations);

d) annual corporate and business unit performance objectives utilized in determining incentive compensation or other awards to officers; and

e) employment contracts, termination and other special arrangements with senior executive officers, or other employee groups if such action is likely to have a subsequent material[1] impact on the Company or its basic human resource and compensation policies.

v) taking all reasonable steps to ensure succession planning programs are in place, including programs to train and develop management;

vi) approving certain matters relating to all employees, including:

a) the annual salary policy/program for employees;

b) new benefit programs or changes to existing programs that would create a change in cost to the Company in excess of $10,000,000 annually;

c) pension fund investment guidelines and the appointment of pension fund managers; and

d) material benefits granted to retiring employees outside of benefits received under approved pension and other benefit programs.

C. Strategy and Plans

The Board has the responsibility to:

i) participate in strategic planning sessions to ensure that management develops, and ultimately approve, major corporate strategies and objectives;

ii) approve capital commitment and expenditure budgets and related operating plans;

iii) approve financial and operating objectives used in determining compensation;

iv) approve the entering into, or withdrawing from, lines of business that are, or are likely to be, material to the Company;

v) approve material divestitures and acquisitions; and

vi) monitor management s achievements in implementing major corporate strategies and objectives, in light of changing circumstances.

D. Financial and Corporate Issues

The Board has the responsibility to:

i) take reasonable steps to ensure the implementation and integrity of the Company s internal control and management information systems;

ii) monitor operational and financial results;

iii) approve annual financial statements and related Management s Discussion and Analysis, review quarterly financial results and approve the release thereof by management;

iv) approve the Management Proxy Circular, Annual Information Form and documents incorporated by reference therein;

v) declare dividends;

vi) approve financings, changes in authorized capital, issue and repurchase of shares, issue and redemption of debt securities, listing of shares and other securities, issue of commercial paper, and related prospectuses and trust indentures;

vii) recommend appointment of external auditors and approve auditors fees;

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1 For purposes of this Charter, the term material includes a transaction or a series of related transactions that would, using reasonable business judgment and assumptions, have a meaningful impact on the Corporation. The impact could be relative to the Corporation s financial performance and liabilities as well as its reputation.

viii) approve banking resolutions and significant changes in banking relationships;

ix) approve appointments, or material changes in relationships with corporate trustees;

x) approve contracts, leases and other arrangements or commitments that may have a material impact on the Company;

xi) approve spending authority guidelines; and

xii) approve the commencement or settlement of litigation that may have a material impact on the Company.

E. Business and Risk Management

The Board has the responsibility to:

i) take reasonable steps to ensure that management has identified the principal risks of the Company s businesses and implemented appropriate strategies to manage these risks, understands the principal risks and achieves a proper balance between risks and benefits;

ii) review reports on capital commitments and expenditures relative to approved budgets;

iii) review operating and financial performance relative to budgets or objectives;

iv) receive, on a regular basis, reports from management on matters relating to, among others, ethical conduct, environmental management, employee health and safety, human rights, and related party transactions; and

v) assess and monitor management control systems by evaluating and assessing information provided by management and others (e.g. internal and external auditors) about the effectiveness of management control systems.

F. Policies and Procedures

The Board has responsibility to:

i) monitor compliance with all significant policies and procedures by which the Company is operated;

ii) direct management to ensure the Company operates at all times within applicable laws and regulations and to the highest ethical and moral standards;

iii) provide policy direction to management while respecting its responsibility for day-to-day management of the Company s businesses; and

iv) review significant new corporate policies or material amendments to existing policies (including, for example, policies regarding business conduct, conflict of interest and the environment).

G. Compliance Reporting and Corporate Communications

The Board has the responsibility to:

i) take all reasonable steps to ensure the Company has in place effective disclosure and communication processes with shareholders and other stakeholders and financial, regulatory and other recipients;

ii) approve interaction with shareholders on all items requiring shareholder response or approval;

iii) take all reasonable steps to ensure that the financial performance of the Company is adequately reported to shareholders, other security holders and regulators on a timely and regular basis;

iv) take all reasonable steps to ensure that financial results are reported fairly and in accordance with generally accepted accounting principles;

v) take all reasonable steps to ensure the timely reporting of any other developments that have significant and material impact on the Company; and

vi) report annually to shareholders on the Board s stewardship for the preceding year (the Annual Report).

IV. GENERAL LEGAL OBLIGATIONS OF THE BOARD OF DIRECTORS

A. The Board is responsible for:

i) directing management to ensure legal requirements have been met and documents and records have been properly prepared, approved and maintained;

ii) approving changes in the By-laws and Articles of Incorporation, matters requiring shareholder approval, and agendas for shareholder meetings;

iii) approving the Company s legal structure, name, logo, mission statement and vision statement; and

iv) performing such functions as it reserves to itself or which cannot, by law, be delegated to Committees of the Board or to management

SCHEDULE F

COMPENSATION DISCUSSION AND ANALYSIS

The following information is excerpted from TransCanada s Proxy Circular. Unless as otherwise defined in this Schedule F , all capitalized terms used from herein shall have the same meaning ascribed to them in TransCanada s Proxy Circular.

This section of the Proxy Circular explains how TransCanada s executive compensation program is designed and operated with respect to the President and CEO (referred to as CEO in this section and under the section entitled Executive Compensation Compensation Tables), Chief Financial Officer (CFO), and the three other most highly compensated executives included in this reported financial year (collectively referred to as the Executive Officers).

This section is divided into the following areas of interest:

1. an introduction outlining TransCanada s business considerations that affect the executive compensation program;
2. summary of business results for 2009;
3. information on TransCanada s executive compensation philosophy and program;
4. an overview of the compensation decision-making process; and
5. a detailed look at the decisions the Human Resources Committee of the Board of Directors (the HR Committee) made with respect to the compensation of the Executive Officers in light of the Company s performance in 2009.

INTRODUCTION

The executive compensation program for TransCanada is managed by the Board of Directors with guidance from the HR Committee. The objective of the executive compensation program is to provide compensation that is competitive, fair, and supportive of the Company s business plans, delivered in such a manner as to be consistent with the best interests of all shareholders. The nature of TransCanada s business impacts the way in which performance is assessed. This performance assessment, in turn, directly impacts how compensation is delivered over time.

TransCanada s businesses are capital intensive, many are subject to regulated returns and growth is typically driven by projects that have long periods of time between conception, approval, construction, startup, and ultimate profitability. Supporting this business portfolio and the strategy for the generation of future shareholder value, as well as maintaining strength in the Company s capital position, requires a balance between short term financial measures, capital management, and longer term profitability. This has been particularly evident during the past few years and will continue to be applicable in the future with the prospects of new large capital projects being considered. The Company is also mindful of the importance of dividends to shareholders and the need for a balance between current returns, a conservative capital structure and long term growth.

The Board recognizes that compensation programs that primarily reward delivery of short term returns could be detrimental to investment in a stream of projects and actions that could promote longer term growth in the value of the Company and growing returns to investors. However, in the other extreme, excessive focus on longer term projects could decrease the Company s ability to generate current earnings, pay dividends, and maintain access to the capital markets. The Board has carefully considered a balanced approach to these issues in the design of the executive compensation program and the impact of compensation systems on business risk.

The Board establishes meaningful performance objectives for management for both the short and long term compensation plans. In establishing these objectives, the Board understands that important elements of executive performance cannot be measured entirely through financial measures. For example, the management of projects under development or under construction is critical to the value of the Company, and the assessment of performance in that regard can be subjective rather than based on numerical measurements. Another important element of performance is how well the management team meets the Company s objectives with

respect to health, safety and the environment. The Board has a rigorous process of both setting these objectives as well as assessing the performance of all executives in consideration of subjective and objective measurement. The final determination of performance is made based on a combination of specific financial measures and the assessment of the other elements of management s responsibility.

Although constantly seeking improvements to the design and administration of TransCanada s executive compensation program, the HR Committee and the Board are confident that the current systems and practices are in the best interest of the shareholders and have operated as they were designed. Shareholders should expect the Board to use the Company s compensation resources wisely to build long term value creation. TransCanada s Board believes that the Company s compensation philosophy and executive compensation program are consistent with this expectation.

SUMMARY FOR 2009

In evaluating 2009 overall corporate performance, the HR Committee and the Board considered a number of qualitative and quantitative factors including financial and share performance, the quality of earnings, execution of on-going projects and transactions, safety, operational performance and progress on key growth initiatives. For 2009, the HR Committee and the Board were of the opinion that the Company performed well and met or exceeded expectations in most areas. This was demonstrated by:

- Cash provided by operations grew 20 per cent to $3.4 billion in 2009 compared to $2.8 billion in 2008;
- Acquired ConocoPhillips remaining interest in Keystone, increasing TransCanada s ownership to 100 per cent;
- Completed construction of the first phase of Keystone to Wood River and Patoka, Illinois;

- Entered into an arrangement with ExxonMobil Corporation for the joint development of the Alaska pipeline and in January 2010, filed its plan with the U.S. Federal Energy Regulatory Commission (FERC) to obtain approval to conduct the first natural gas pipeline open season to develop Alaska s vast natural gas resources;
- Portlands Energy and the first phase of Kibby Wind were placed into service; and
- Issued approximately $6 billion of debt and equity financing during a challenging North American economic environment.

For 2009, the HR Committee and the Board concluded that overall, the Company met its performance objectives but also recognized below-expectation performance of total shareholder return. This assessment did not trigger any specific awards for the Executive Officers but served to provide general context for the review by the HR Committee and the Board of the Executive Officers individual performance. They also recognized that uncertainties in the global economy and volatility in the world capital markets continue to present challenges and, as a result, a moderate approach to executive compensation was appropriate. They used the following guiding principles during their 2010 Total Direct Compensation deliberations:

- base salary increases for the Executive Officers only for significant additional responsibilities;
- annual bonus awards that reflect each of the Executive Officer s contribution to TransCanada s overall corporate performance for 2009; and
- moderate or no increases in longer-term incentive award levels except to recognize significant additional responsibilities.

The HR Committee and the Board considered the results achieved against the pre-established three-year performance objectives for the 2007 performance share unit grant and determined that 85% of the outstanding units would vest for payment. This vesting level represented performance that was below target but above threshold , as determined by the HR Committee and the Board in accordance with the vesting guidelines described in more detail below in the section Elements of Compensation Overview of Compensation Elements under the element Medium-term incentive .

More information regarding the 2007 performance share unit grant is in the section Compensation Decisions Made in 2010 Reflecting 2009 Performance Mid-term Incentive Performance , below.

The following chart shows the relationship between the annual outcomes of selected key financial metrics from 2005 to 2009 and the sum of Total Direct Compensation that was awarded to the Executive Officers after the completion of the noted year:

Details regarding the Total Direct Compensation decisions made by the HR Committee and the Board in 2010 for each Executive Officer s base pay, annual cash bonuses, performance share unit grants and stock option grants, based on overall performance in 2009 are noted in the section Compensation Decisions Made in 2010 Reflecting 2009 Performance - Executive Officer Profiles , below.

COMPENSATION PHILOSOPHY

TransCanada s executive compensation program has the following objectives:

- to provide a compensation package that proportionally rewards individual contributions in the context of overall business results (pay-for-performance);
- to be competitive in level and form with the external market;
- to align executives interests with shareholders and customers; and

- to support the attraction, engagement and retention of executives.

The compensation program is also designed to align with the Company s business plans and risk management framework to provide an appropriate balance between risk and executive rewards.

Market Benchmarking & Comparator Group

The HR Committee considers comparable compensation data from Canadian-based energy companies that are generally of similar size and scope to TransCanada, and that represents the market in which TransCanada may compete for talent (the Comparator Group). The Company also evaluates broader industry trends and practices to determine the appropriate elements of compensation and the effective design of each element.

The composition of the Comparator Group is reviewed annually by the HR Committee for its on-going business relevance to TransCanada. An overview of the characteristics of the Comparator Group, as compared to TransCanada s characteristics, is provided in the following table:

	TRANSCANADA	**COMPARATOR GROUP**	
INDUSTRY	North American Pipelines, Power	North American Pipelines, Power, Utilities; Canadian Oil and Gas	
LOCATION	Calgary, Alberta	Principally Alberta	
		MEDIAN	**75th PERCENTILE**
REVENUE(1)	$8.6 billion	$8.6 billion	$24.2 billion
MARKET CAPITALIZATION(2)	$24.8 billion	$20.0 billion	$34.5 billion
ASSETS(1)	$39.4 billion	$18.2 billion	$31.5 billion
EMPLOYEES(1)	Approximately 4,000	3,189	5,826

(1) Revenue, assets and number of employees reflect 2008 information.

(2) Market Capitalization value noted is calculated as at December 31, 2009 by multiplying the monthly closing price of common shares by the quarterly common shares outstanding for the most recently available quarter.

(3) The members of the Compensation Comparator Group for 2009 were as follows:

Alliance Pipeline Ltd.	Emera Inc.	Nexen Inc.
ATCO Ltd. & Canadian	Enbridge Inc. / Enbridge Pipelines Inc.	Petro-Canada Shell Canada Ltd.
Utilities Limited	EnCana Corporation	Spectra Energy Suncor Energy Inc.
ATCO Power	EPCOR Utilities Inc.	Syncrude Canada Ltd.
BP Canada Energy Company	ExxonMobil Canada Fortis Inc.	Talisman Energy Inc.
Canadian Natural Resources Ltd.	Husky Energy Inc.	TransAlta Corporation
Chevron Canada Limited	Imperial Oil Ltd.	
ConocoPhillips Canada Resources Ltd.	Kinder Morgan Canada Inc.	
Devon Canada Corporation		

Each Executive Officer s position is benchmarked against similar positions in the Comparator Group. The position-based compensation data from the Comparator Group (the Comparator Market Data) provides the initial pay reference point for the HR Committee. The annual Total Direct Compensation value an Executive Officer is awarded will vary based on an assessment of individual performance in the context of overall corporate performance, and will generally be set in accordance with the following guidelines (the Pay Positioning Guidelines):

Pay Positioning Guidelines

IF AN EXECUTIVE S PERFORMANCE		TOTAL DIRECT COMPENSATION WILL BE
meets objectives	à	generally comparable to median Total Direct Compensation market data
exceeds objectives	à	generally comparable to above-median Total Direct Compensation market data(1)
falls short of objectives	à	adjusted downward from the previous year(2)

(1) The degree to which an Executive Officer s Total Direct Compensation value is positioned above the median is relative to his or her assessed individual performance level.

(2) The degree to which the pay is adjusted downward is also relative to individual performance. The adjustment is typically made through variable rather than fixed compensation.

ELEMENTS OF COMPENSATION

Total Direct Compensation is an absolute dollar value that is determined based on a desired positioning to the Comparator Market Data. This value is then allocated to the different forms of compensation:

The allocation of Total Direct Compensation value to the different compensation elements is not based on a set formula. The allocation is at the discretion of the HR Committee and the Board and is intended to reflect such things as market practices regarding the relative weighting afforded the different compensation elements (i.e., pay-mix) as well as their assessment of each of the Executive Officer s past contribution and ability to contribute to future short, medium and long-term business results.

Overview of Compensation Elements

Component	Element	Form	Performance Period	Key Features	Purpose
FIXED	Base salary	Cash	1 year	• Generally targeted around the median market data for similar roles. • Variance from median may be due to sustained individual high performance, the scope of the executive s role within TransCanada, retention considerations and/or material differences in an Executive Officer s responsibilities compared with similar roles in the Comparator Market Data. • Reviewed annually; changes, if any, typically made effective April 1.	• Provide income certainty. • Attract and retain executives.

Component	**Element**	**Form**	**Performance Period**	**Key Features**	**Purpose**
VARIABLE OR AT-RISK	Short-term incentive	Annual cash bonus	1 year	• Award is based on the HR Committee and Board s assessment of each Executive Officer s yearly individual contribution and performance against personal objectives in the context of overall annual corporate performance. • Specific target compensation values are not pre-set but consideration is given to Comparator Market Data when determining the award amount.	• Motivate executives to achieve key annual business priorities and objectives. • Reward executives for relative annual contribution to the Company. • Align executives interests with those of the shareholders. • Attract and retain executives.
	Medium-term incentive	Performance share units	Up to 3 years with vesting at end of term	• The Executive Share Unit Plan grants notional share units based on the allocated value of Total Longer-term Compensation divided by the fair market value of TransCanada s common shares at the time of grant. • Value of common share dividends accrued through three-year term. • Number of units that vest for payment is subject to the attainment of specific performance objectives, as determined by the HR Committee and the Board. (1) • The final payment is made in cash, less statutory withholdings.	• Motivate executives to achieve medium-term business objectives. • Align executives interests with those of the shareholders. • Attract and retain executives.
	Long-term incentive	Stock options	Vesting 33 1⁄3% at the end of each year for 3 years. Grants have a 7 year term	• Stock options granted based on the allocated value of Total Longer-term Compensation divided by a compensation value per option which reflects the grant date fair value, as determined by the HR Committee. • Exercise price is the closing market price of TransCanada common shares on the TSX on the last trading day immediately preceding the grant date of the stock option. • Participants benefit only if the market value of TransCanada s common shares at the time of stock option exercise is greater than the exercise price of the stock options at the time of grant.	• Motivate executives to achieve long-term sustainable business objectives. • Align executives interests with those of the shareholders. • Attract and retain executives.

(1) The number of units vesting relative to corporate performance results is in accordance with the following guidelines:.

PERFORMANCE LEVEL		GENERAL DESCRIPTION		UNITS VESTING(1)
Below threshold	à	Results which are below an acceptable level of performance	à	zero units vest; no payment is made
At threshold	à	Results which are lower than expected, but still acceptable performance	à	50% of units vest for payment

		Between threshold and target, vesting on a pro-rata basis		
At target	à	Results which are considered a stretch, but achievable; fully meet expectations	à	100% of units vest for payment
		Between target and maximum, vesting on a pro-rata basis		
At or above maximum	à	Results which are considered a substantial stretch; significantly exceed expectations	à	150% of units vest for payment

Other Compensation

Executive Officers receive other benefits that the Company believes are reasonable and consistent with the overall executive compensation program. These benefits are based on competitive market practices and support the attraction and retention of Executive Officers. Benefits include a defined benefit pension plan (described below in the section, Pension and Retirement Benefits for Executives), traditional health and welfare programs and executive perquisites.

The perquisite program provides a limited number of perquisites to the Executive Officers in 2009 which include:

- an annual perquisite cash allowance to use for any purpose at the discretion of the Executive Officer valued at $4,500;
- a limited number of luncheon and/or recreation club memberships, based on business need;
- a Company-paid reserved parking stall valued at $5,440; and
- an annual car allowance valued at $18,000.

The Committee may, from time to time, convey other benefits to an Executive Officer under specific circumstances or as a retention mechanism. If provided, such non-policy perquisites will be outlined in the footnotes to the Summary Compensation Table in the section, Executive Compensation Tables , below.

Annually, the HR Committee reviews the Executive Officers expenses and use by all executives of the corporate aircraft. TransCanada permits the use of the corporate aircraft by any executive including the CEO only when it is integrally and directly related to performing the executive s job.

Share Ownership Guidelines

The HR Committee has instituted share ownership guidelines for executives (the Guidelines) that encourage executives to achieve an ownership level in the Company that the HR Committee views as significant in relation to each executive s base salary. Minimum ownership requirement is a multiple of base salary depending on the role of executive. Executives generally have five years to meet this requirement. Once an executive is deemed to have reached the minimum ownership requirement, the HR Committee uses discretion in the maintenance of this level in the event of subsequent share price fluctuations. The level of ownership can be achieved through the purchase of common shares or units, by participation in the TransCanada Dividend Reinvestment Plan or through unvested performance share units. The Guidelines require that at least 50% of the ownership level be in actual shares (i.e., TransCanada common shares or units of any TransCanada sponsored limited partnership). Unvested performance share units from the Executive Share Unit Plan only count to a maximum of 50% of the ownership level.

The HR Committee annually reviews a calculation of ownership levels under the Guidelines and, in 2009, noted that all Executive Officers had met their minimum ownership requirements. Ownership level calculations pursuant to the Guidelines for the Executive Officers are found in the section, Compensation Decisions Made in 2010 Reflecting 2009 Performance Executive Officer Profiles .

COMPENSATION DECISION-MAKING PROCESS

Overview

The following is a general overview of the process used to determine the Total Direct Compensation awards for Executive Officers:

Roles & Responsibilities

Contributor	Key Accountabilities
TransCanada s Human Resources Management	• Acquires, analyzes and interprets all compensation market data used by the CEO in the formulation of Total Direct Compensation recommendations for his direct reports.

	• Provides the HR Committee and the Chair of the Board with relevant market data and other information, as requested, in order to support the HR Committee s deliberations regarding the CEO s Total Direct Compensation.
Chief Executive Officer	• Engages in discussions with the HR Committee concerning the determination of performance objectives for the Executive Officers and the assessment of whether, and to what extent, criteria for the previous year have been achieved by those individuals. • Makes recommendations to the HR Committee regarding the level and form of compensation awards for his direct and certain indirect reports. • Reviews, evaluates and recommends to the Board all key performance objectives, measures and metrics used for compensation-related purposes. • Provides a self-assessment of his own performance for the HR Committee and the Board.
HR Committee	• Directs management and/or the HR Committee s Consultant and other advisors to gather information on its behalf, and provide initial analysis and commentary. • Determines and recommends for approval to the Board all remuneration to be awarded through the executive compensation program to the Executive Officers.
External Compensation Consultant to the HR Committee	• The Consultant s mandate is to: o provide an assessment of management s proposals relating to the compensation of the Executive Officers; o attend all HR Committee meetings (unless otherwise requested by the HR Committee Chair); and o provide data, analysis or opinion on compensation-related matters if requested by the HR Committee Chair. • At every meeting, meets with the HR Committee without members of management present. • Communicates directly with members of the HR Committee outside of the HR Committee s meetings as requested by the HR Committee members. • Upon direction and approval from the HR Committee Chair, may provide consulting advice to TransCanada management.

Contributor	Key Accountabilities
Other Advisors to the HR Committee	• Provide non-compensation-related services, as required and directed by the HR Committee Chair.
Board	• Reviews and approves all remuneration to be awarded through the executive compensation program to the Executive Officers, in consideration of recommendations from the HR Committee.

The Independence of the External Compensation Consultant to the HR Committee

The HR Committee has retained the services of an individual consultant (the Consultant) from Towers Watson (formerly Towers Perrin) as the HR Committee s advisor on human resources matters. The HR Committee chose the individual consultant it believed would provide the highest quality of independent advice. The fact that the Consultant is employed by Towers Watson, a pre-eminent human resources consulting firm that also provides services to TransCanada in several areas, was known to the HR Committee at the time of the Consultant s original engagement. It is the HR Committee s view that the Consultant is capable of providing candid and direct advice independent of management s influence.

Numerous steps have been taken by both Towers Watson and TransCanada to satisfy the objective of ensuring the Consultant s independence.

- Towers Watson has confirmed that no part of the Consultant s pay is directly impacted by growth or decline of Towers Watson s services to TransCanada. Towers Watson has also ensured that the Consultant:

  - is not the client relationship manager for services provided to the Company;
  - does not participate in any client development activities related to increasing Towers Watson s consulting services to TransCanada; and
  - other than consulting for the HR Committee, does not work on any other consulting assignments for TransCanada.

- TransCanada has ensured that the Consultant:

  - reports to, and interacts directly with, the HR Committee on all matters related to executive compensation; and
  - has limited interactions with management unless specifically related to those matters for which the Consultant is engaged on the Committee s behalf or in relation to proposals that will be presented to the HR Committee for review or approval.

The fees paid to Towers Watson in 2009 for the Consultant s services to the HR Committee were approximately $131,000.

The HR Committee annually reviews the projects performed for TransCanada by other consultants at Towers Watson and the fees charged for the services rendered. For 2009, these services included providing the Company s Human Resources Management with executive, non-executive and Board member compensation market data, as well as benefit and pension actuarial consulting services for both U.S. and Canadian operations. The aggregate fees billed by Towers Watson to the Company for 2009 (exclusive of the Consultant s fees) were approximately $2.5 million.

Stock Option Granting Process

Generally, stock option grants are determined as part of the annual deliberations regarding Total Direct Compensation. The process is as follows:

- The CEO recommends to the HR Committee the stock option grant value for all executives (except his own).

- HR Committee recommends the stock option grant value for Executive Officers (including the CEO) to the Board and approves the stock option grant value for all other executives.

- The Board approves the value of the Executive Officers stock options grants.
- The HR Committee approves all individual stock option grants.

Internal Equity and Retention Value

Executive Officer compensation relative to other executives at TransCanada (internal equity) is informally taken into account by the HR Committee and the Board during the annual Total Direct Compensation deliberations. This is especially true when the benchmark data for a particular role does not reflect the relative scope of TransCanada s role. In such cases, other internal roles that have strong market data may be used to complete an assessment of relativity.

The HR Committee and the Board also consider the retentive potential of its compensation decisions. Retention of the Executive Officers is critical to business continuity, stakeholder relationship management, succession planning and achieving the desired short and longer-term results for the Company.

Previously Awarded Compensation

The HR Committee approves or recommends compensation awards, including stock options, which are not contingent on the number, term or current value of other outstanding compensation previously awarded to the individual. The HR Committee believes that reducing or limiting current stock option grants, performance share units or other forms of compensation because of prior gains realized by an Executive Officer would unfairly penalize the executive and reduce the motivation for continued high achievement. Similarly, the HR Committee does not purposefully increase total longer-term compensation value in a given year to offset less-than-expected returns from previous awards.

The HR Committee receives tally sheets which provide context for the decisions they make in relation to Total Direct Compensation. Although this information does not necessarily drive decision making with regard to specific pay elements, these tally sheets enable the HR Committee to:

- complete an overall assessment of Total Direct Compensation levels in relation to performance;
- evaluate pay mix;
- for equity-based compensation, assess level of wealth creation opportunities afforded and the potential retention risks due to unvested and/or out-of-the money values; and
- determine if changes are required to severance plans or employment agreements to ensure alignment with the Company s business and executive attraction and retention objectives.

The tally sheets used by the HR Committee include the following information:

Analysis	Description
Three-year Total Direct Compensation History	• Three-year history of each Executive Officer s and certain other executives previously awarded Total Direct Compensation on an element by element basis. • Enables the HR Committee to track changes in an Executive Officer s Total Direct Compensation from year to year and to remain aware of the historical performance assessments and resulting compensation for each individual.

Analysis	**Description**
Economic Impact Analysis	• Models compensation scenarios for the Executive Officers and certain other executives that illustrate the impact of various future corporate performance outcomes on previously awarded and outstanding compensation. • Allows the HR Committee to determine if modelled compensation results are reasonable and deliver the expected level of differentiation of compensation value based on performance, as understood by the HR Committee. • Following their 2009 review of the resulting analyses, the HR Committee was satisfied that, in aggregate, there had been an appropriate pay for performance relationship for the Executive Officers.
Compensation Look-back Analysis	• A summary showing each Executive Officer s total income (i.e., realized and accrued) since his or her appointment to a position or based on his or her tenure with the Company. • The 2009 analysis included total pay realized/accrued by the Executive Officers since January 1, 2005 or the period they had served as an Executive Officer, if less. • The HR Committee requests this information from the Consultant on a bi-annual basis.
Severance/Change of Control Modeling	• Calculates severance payment amounts for each of the Executive Officers as calculated under separation agreements made with each Executive Officer. • The data annually provided to the HR Committee represents the total value to be paid to the Executive Officer in the event of termination without cause, both with and without a deemed change of control as well as the additional payment that could be made under a non-competition provision.

Performance Assessment

The Board approves annual corporate objectives that reflect the incremental achievements necessary to support the Company s core strategies. The HR Committee and the Board s comprehensive assessment of the results achieved against the annual corporate objectives and related business circumstances provides the context for the evaluation of the individual Executive Officers for Total Direct Compensation.

CORE STRATEGIES

The core strategies guide how TransCanada deploys resources that will allow the Company to achieve its vision of being the leading energy infrastructure company in North America.

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ANNUAL CORPORATE OBJECTIVES

The Board approves annual corporate objectives that support TransCanada s core strategies for growth and value creation. These quantitative and qualitative objectives are referenced by the HR Committee and the Board for compensation decision-making. The HR Committee and the Board s assessment of overall corporate performance provides general context for the review of the individual performance of the Executive Officers.

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INDIVIDUAL OBJECTIVES FOR THE EXECUTIVE OFFICERS

The HR Committee and the Board approve annual individual performance objectives for the Executive Officers that align with the annual corporate objectives and reflect key performance areas for each executive relative to their specific role. The HR Committee s assessment of individual Executive Officer s results achieved is considered in recommending the level of Total Direct Compensation to be approved by the Board.

COMPENSATION DECISIONS MADE IN 2010 REFLECTING 2009 PERFORMANCE

Overall Corporate Performance

TransCanada s corporate performance is measured by how well the Company achieves annual corporate objectives as evidenced by financial and operational results that support the Company s core strategies. The table below highlights TransCanada s key financial objectives and results for 2009 as compared with the previous two years:

Key Financial Measures (millions of dollars)(1)	**2009 Objectives(2)**	**2009 Results**	**2008 Results**	**2007 Results**
Net Income	1,308 to 1,388	1,325	1,279	1,100
Funds Generated From Operations	2,919 to 3,031	3,080	2,811	2,621
Key Per Share Measures ($)				
Comparable Earnings per Share - Basic(3)	2.12 to 2.25	2.03	2.25	2.08
Funds Generated From Operations Per Share - Basic(3)	4.73 to 4.93	4.72	5.30	4.95

(1) All values are expressed in Canadian dollars.

(2) Values denote the range of outcomes that represent satisfactory to exceed expectations performance.

(3) The 2009 objectives for Comparable EPS were established based on the weighted average shares outstanding in 2008 of 616 million. The 2009 results noted in the table reflect the weighted average shares outstanding in 2009 of 652 million. For comparative purposes, the 2009 results noted below have been adjusted relative to the number of shares outstanding in 2008:

- Earnings per Share = $2.15 (or above satisfactory);
- Funds Generated From Operations Per Share = $4.99 (or above exceeds expectations)

The following table highlights the business results achieved in 2009 that support each of the strategies:

Core Strategies	**Results Achieved in 2009**
Maximize the full-life value of TransCanada s infrastructure assets and commercial positions	• Canadian Pipelines achieved excellent financial and business performance, with strong earnings before interest, taxes, depreciation and amortization (EBITDA), operational efficiencies and made significant progress on several complex commercial initiatives. • U.S. Pipelines had strong financial performance from Iroquois, Great Lakes and ANR pipeline systems; performance was as expected from PNGTS, GTN and Northern Border pipeline systems. Significant progress was made on the restructuring and consolidation of U.S. Pipelines in Houston. • Western Power financial results were below expectations, however noteworthy results were achieved on longer term initiatives. • Eastern Power demonstrated excellent physical and commercial performance and achieved financial performance expectations. The year presented the successful start-up of the Portlands Energy Centre, which was completed under budget, and strong financial results from Bécancour, Grandview, and Cartier Wind generating facilities. • Bruce Power exceeded financial performance expectations and also completed a critical commercial restructuring agreement; however it had project management challenges from a timing and cost perspective. • The Ravenswood integration was successfully completed and the first phase of the Kibby Wind development was placed in service ahead of schedule and completed under budget, but the financial performance of U.S. Power was weak due to low power prices. • Gas Storage realized exceptionally strong financial performance.
Cultivate a focused portfolio of high quality development options	• The Pipelines business achieved notable project developments that include Bison, Manzanillo, British Columbia shale gas connections and Canadian system expansions. Potential major advances include the Keystone oil expansion, the Alaska partnership with ExxonMobil Corporation and the restructured Mackenzie project. • The Energy business attained notable development outcomes that included the contract for the Oakville generating station, Zephyr transmission project, and numerous early-stage thermal and renewable power and gas storage projects.
Commercially develop and physically execute new asset investment program	• TransCanada successfully executed the largest annual capital program in its corporate history, coming in under budget on a diverse suite of Energy and Pipeline projects. • The Company also completed the acquisition of all partner interests in the Keystone oil pipeline project. • Project management on both Energy and Pipeline projects was noteworthy, with strong teams, excellent project management systems, and strong support from all corporate departments.
Maximize TransCanada s competitive strengths	• TransCanada continued to build its competitive position through steady improvement in market knowledge, relationships and reputation. Notably, the consolidation of U.S. Pipelines commercial functions in Houston will offer a stronger and more effective presence in the U.S. Pipeline business. • The Company continued to advance its industry leading position as a superior asset operator with break-through performance in safety and operations

	• Significant progress was achieved on people and organizational objectives, through employee and leadership development, better performance management, and a streamlined organization. • The Company successfully financed the largest capital program in its history, while maintaining balance sheet ratios.
Maximize TransCanada s reputation and standing in financial markets	• TransCanada worked closely with credit rating agencies, banks, and institutional investors to maintain an A grade debt rating while raising significant new capital to finance its capital program. • The Company worked diligently to maintain and enhance the confidence of equity analysts, investors, and the financial press. • TransCanada debt is consistently rated low risk; TransCanada equity is consistently rated a buy for long term growth and value creation.

Further information regarding TransCanada s corporate financial and business performance can be found in the 2009 Management Discussion and Analysis in TransCanada s 2009 Annual Report.

The HR Committee and the Board noted that during 2009 the Company made significant progress in successfully executing its $22 billion capital program. The program has been well managed and the projects are largely being completed on time and at or below budget. During 2008 and 2009, $2.4 billion of common and preferred equity was raised to finance this significant portfolio of quality infrastructure projects. These equity issuances were viewed as prudent and necessary to allow the Company to maintain its financial capacity and credit ratings which are critical to its ability to continue to grow. It was also noted that the projects currently under development will deliver incremental value to shareholders in coming years. It was recognized that the equity issuance in 2009 had a dilutive impact on the Company s annual earnings per share results. While total earnings were up year over year, on a per share basis the results decreased. This had a related negative impact on the Company s stock price performance and resulted in a below-expectation performance of Total Shareholder Return for the year.

Looking forward, the HR Committee and the Board agreed that TransCanada should be in a position to generate strong, long-term financial returns for shareholders as a result of the growing portfolio of high-quality energy infrastructure assets, proven project development and execution capabilities and the Company s strong financial position. They also reviewed the operational results of the Company, including its customer ratings, health, safety and environment and other measures.

For 2009, the HR Committee and the Board concluded that overall, the Company met its performance objectives. After considering these performance results, they determined that overall corporate performance in 2009 was at target and that this rating would serve to provide context for the 2010 review of compensation for the Executive Officers. The Total Direct Compensation awarded to the Executives Officers reflects the results achieved in their respective key performance areas.

In addition, the Board approved 2010 annual corporate objectives that continue to focus on achieving the financial and operational results that support TransCanada s core strategies for growth and value creation.

Medium-term Incentives

2007 Performance Share Unit Grant Payout

As noted in the table above, Overview of Compensation Elements for the Medium-term incentive element, the Executive Share Unit Plan provides for vesting from zero to 150% of units granted based on the HR Committee and Board s assessment of performance over the course of the three-year term. They considered the following three-year performance results as the basis for their decision:

MEASURE	PERIOD	THRESHOLD	TARGET	MAXIMUM	RESULTS
Percent growth of Absolute Total Shareholder Return (TSR)	Jan/07 to Dec/09 (1)	11%	27%	40%	**0.31%**
Relative TSR against the Peer Group(2)	Jan/07 to Dec/09 (1)	P25 (25th percentile)	P50 (50th percentile)	P75 (75th percentile)	**Between P25 and P50**
Earnings per Share (EPS) *(comparable, equity method)*	Cumulative Annual Results 2007 2009(3)(4)	$5.13	$5.71	$6.02	**$6.37**
Funds Generated from Operations per Share (FGFOPS) *(equity method)*	Cumulative Annual Results 2007 2009(3)(4)	$12.24	$12.87	$13.18	**$13.40**

(1) Results for TSR measures reported as of December 31, 2009 where the closing share price was $36.19

(2) The members of the Peer Group for this performance share unit grant included the following companies:

Canadian Utilities Inc.	Enbridge Inc.	Southern Union Company
Dominion Resources DTE (Detroit Edison)	Entergy Corporation	Spectra Energy Corp.
Duke Energy Corporation	Exelon Corporation Fortis Inc.	TransAlta Corporation
El Paso Emera Inc.	Sempra Corporation Southern Company	Williams Companies, Inc. (The)
		Xcel Energy Inc.

(3) Targets for financial measures are set based on the sum total of annual objectives over the noted period.

(4) Results for financial measures are based on the final audited results as of December 31, 2009.

The HR Committee and the Board reviewed, in detail, the performance results for the 2007 grant of performance share units. They determined that 85% of the outstanding units would vest for payment. This vesting level represented performance that was below target , but above threshold level in accordance with the vesting guidelines described in more detail in footnote 1 to the table Overview of Compensation Elements for the Medium-term incentive element, above. Although specific weightings for the performance measures were not approved for the 2007 grant, the following performance results were considered against the pre-established three-year corporate performance objectives for the 2007 grant by the HR Committee and the Board in making the final payout determination:

- TransCanada s absolute TSR did not reach the threshold level and therefore was equivalent to a vesting level of 0%.
- The relative TSR measure was between the target level (a 100% vesting level) and the threshold level (a 50% vesting level).
- The two financial measures for which management had the most control, EPS and FGFOPS, posted results that were over the maximum performance level (or 150% vesting level).

Applying equal weight to the performance results would have led to a 95% vesting level or very close to target . However, the HR Committee and the Board placed more emphasis on the absolute and relative TSR and determined that an 85% vesting level was more appropriately aligned with shareholder interests.

More information regarding the value paid to the Executive Officers from the vesting of the 2007 performance share unit grant can be found in the section Incentive Plan Awards Value Vested During the Year , below.

2010 Performance Share Unit Grant

For this grant, the HR Committee approved the following performance measures for the three-year term and weightings for each category:

Executive Officer Profiles

The following profiles for each of the Executive Officers provide the following information:

- a summary of key performance accomplishments for 2009;
- the Total Direct Compensation awarded by the Board to each Executive Officer in 2010 for performance in 2009(1);
- previous two-year awarded compensation history;
- the resulting pay-mix from 2010 compensation award; and
- share ownership status at year end.

(1) *This information is supplemental to, and not intended as a replacement for the data which is required to be disclosed in the Summary Compensation Table.*

For profiles in this section, all compensation values listed resulted from the HR Committee and Board s annual Total Direct Compensation deliberation process. Any compensation awarded to an Executive Officer during the noted financial year but outside of that process is captured in footnotes to the Awarded Compensation table in their profile.

Harold (Hal) N. Kvisle

President & Chief Executive Officer

Key Performance Accomplishments in 2009

- Target achievement of overall corporate objectives.
- Significant progress in business development, with tangible progress on long-term, large-scale growth initiatives.
- Successful financing of the largest capital program in company history while maintaining balance sheet ratios.
- Significant progress in the areas of leadership development and succession planning; high levels of employee engagement across the organization; substantial organizational efficiencies gained through consolidation of U.S. commercial operations.
- Continued strengthening of relationships in the regulatory, political and business arenas, leading to positive project and commercial outcomes in Pipelines and Energy.

AWARDED COMPENSATION	**2010 ($)**	**2009 ($)**	**2008 ($)**
FIXED			
Annual Base Salary(1)	1,250,000	1,250,000	1,250,000
VARIABLE			
Cash Bonus(2)	1,650,000	1,850,000	1,550,000
Performance Share Units(3)	3,000,000	3,040,000	3,000,000
Stock Options(4)	1,000,000	960,000	1,000,000
TOTAL DIRECT COMPENSATION	**6,900,000**	**7,100,000**	**6,800,000**
Change from previous year	-3%	+ 4%	-

2010 PAY MIX(5)

OWNERSHIP(6)

Minimum Ownership Level	Minimum Ownership Value ($)	Total Ownership Value under the Guidelines ($)	Total Ownership as a Multiple of Base Salary
3 x	3,750,000	4,896,371	3.9x

(1) The annual base salary rate as at April 1st of the noted year.

(2) The total cash bonus awarded for performance attributable to the noted financial year, and paid in the first quarter following the completion of the financial year.

(3) The value of performance share units awarded during the annual granting process for the noted year.

(4) The compensation value of stock options granted during the annual granting process for the noted year.

(5) Pay mix is the resulting relative value of each compensation element following the allocation of Total Direct Compensation value and is expressed as a percentage of Total Direct Compensation.

(6) Value of ownership determined as at December 31, 2009, using the 20 day volume-weighted average closing price of TransCanada s common shares of $35.36 and the 20 day volume-weighted average closing price of TC PipeLines, LP units of $36.26. For further information regarding the Share Ownership Guidelines, refer to the section Elements of Compensation - Share Ownership Guidelines , above.

Gregory (Greg) A. Lohnes

Executive Vice-President and Chief Financial Officer

Key Performance Accomplishments in 2009

- Successful financing of the largest capital program in company history while maintaining balance sheet ratios.
- Counterparty defaults negligible in difficult economic conditions.
- Strengthened relationships with Canadian, U.S. and European major shareholders and debt holders.
- Significant improvements in the clarity of quarterly financial reporting, with sound plans to transition to International Financial Reporting Standards (IFRS) in 2011.

AWARDED COMPENSATION	**2010 ($)**	**2009 ($)**	**2008 ($)**
FIXED			
Annual Base Salary(1)	430,000	430,000	430,000
VARIABLE			
Cash Bonus(2)	600,000	550,000	490,000
Performance Share Units(3)	615,000	584,000	547,500
Stock Options(4)	205,000	216,000	182,500
TOTAL DIRECT COMPENSATION	**1,850,000**	**1,780,000**	**1,650,000**
Change from previous year	+4%	+8%	-

2010 PAY MIX(5)

OWNERSHIP(6)

Minimum Ownership Level	**Minimum Ownership Value ($)**	**Total Ownership Value under the Guidelines ($)**	**Total Ownership as a Multiple of Base Salary**
2 x	860,000	1,086,211	2.5 x

(1) The annual base salary rate as at April 1st of the noted year.
(2) The total cash bonus awarded for performance attributable to the noted financial year, and paid in the first quarter following the completion of the financial year.
(3) The value of performance share units awarded during the annual granting process for the noted year.
(4) The compensation value of stock options granted during the annual granting process for the noted year.
(5) Pay mix is the resulting relative value of each compensation element following the allocation of Total Direct Compensation value and is expressed as a percentage of Total Direct Compensation.

(6) Value of ownership determined as at December 31, 2009, using the 20 day volume-weighted average closing price of TransCanada s common shares of $35.36 and the 20 day volume-weighted average closing price of TC PipeLines, LP units of $36.26. For further information regarding the Share Ownership Guidelines, refer to the section Elements of Compensation - Share Ownership Guidelines , above.

Russell (Russ) K. Girling

Chief Operating Officer

Key Performance Accomplishments in 2009

- Strong financial performance in Pipelines in the face of weak economic conditions, with positive outcomes in the regulatory arena.
- Successful transition to the role of Chief Operating Officer, demonstrating strong leadership across expanded responsibilities.
- Significant progress in business development, capturing significant near-term investment opportunities and progressing long-term, large-scale growth initiatives.
- Substantial organizational efficiencies gained through consolidation of U.S. Pipeline commercial operations.
- Successful completion of the construction of the first phase of the Keystone oil pipeline project.

AWARDED COMPENSATION	**2010 ($)**	**2009* ($)**	**2008 ($)**
FIXED			
Annual Base Salary(1)	800,000	700,000	700,000
VARIABLE			
Cash Bonus(2)	900,000	950,000	900,000
Performance Share Units(3)	2,100,000	1,520,000	1,500,000
Stock Options(4)	700,000	480,000	500,000
TOTAL DIRECT COMPENSATION	**4,500,000**	**3,650,000**	**3,600,000**
Change from previous year	+23%	+1%	-

* In recognition of his promotion to Chief Operating Officer, in September 2009, the HR Committee increased Mr. Girling s annual base salary rate to $800,000 and awarded him a special stock option grant valued at $479,000. As a result of these mid-year changes, Mr. Girling s Total Direct Compensation value was increased to $4,229,000.

2010 PAY MIX(5)

OWNERSHIP(6)

Minimum Ownership Level	**Minimum Ownership Value ($)**	**Total Ownership Value under the Guidelines ($)**	**Total Ownership as a Multiple of Base Salary**
2 x	1,600,000	2,217,537	2.8 x

(1) The annual base salary rate as at April 1st of the noted year.

(2) The total cash bonus awarded for performance attributable to the noted financial year, and paid in the first quarter following the completion of the financial year.

(3) The value of performance share units awarded during the annual granting process for the noted year.

(4) The compensation value of stock options granted during the annual granting process for the noted year.

(5) Pay mix is the resulting relative value of each compensation element following the allocation of Total Direct Compensation value and is expressed as a percentage of Total Direct Compensation.

(6) Value of ownership determined as at December 31, 2009, using the 20 day volume-weighted average closing price of TransCanada s common shares of $35.36 and the 20 day volume-weighted average closing price of TC PipeLines, LP units of $36.26. For further information regarding the Share Ownership Guidelines, refer to the section Elements of Compensation - Share Ownership Guidelines , above.

Alexander (Alex) J. Pourbaix

President, Energy and Executive Vice-President Corporate Development

Key Performance Accomplishments in 2009

- Strong financial performance in Eastern Power, Bruce Power and the natural gas storage business.
- Noteworthy results achieved on longer term initiatives in Western Power and U.S. Power.
- Continuing success in new business development.
- Effective commercial integration of new assets and businesses.
- Strong focus on sustaining TransCanada s Energy businesses over the longer term.

AWARDED COMPENSATION	**2010 ($)**	**2009 ($)**	**2008 ($)**
FIXED			
Annual Base Salary(1)	700,000	700,000	700,000
VARIABLE			
Cash Bonus(2)	740,000	900,000	900,000
Performance Share Units(3)	1,500,000	1,520,000	1,500,000
Stock Options(4)	500,000	480,000	500,000
Total Direct Compensation	**3,440,000**	**3,600,000**	**3,600,000**
Change from previous year	-4%	0%	-

2010 PAY MIX(5)

OWNERSHIP(6)

Minimum Ownership Level	**Minimum Ownership Value ($)**	**Total Ownership Value under the Guidelines ($)**	**Total Ownership as a Multiple of Base Salary**
2 x	1,400,000	1,635,095	2.3 x

(1) The annual base salary rate as at April 1st of the noted year.

(2) The total cash bonus awarded for performance attributable to the noted financial year, and paid in the first quarter following the completion of the financial year.

(3) The value of performance share units awarded during the annual granting process for the noted year.

(4) The compensation value of stock options granted during the annual granting process for the noted year.

(5) Pay mix is the resulting relative value of each compensation element following the allocation of Total Direct Compensation value and is expressed as a percentage of Total Direct Compensation.

(6) Value of ownership determined as at December 31, 2009 using the 20 day volume-weighted average closing price of TransCanada s common shares of $35.36 and the 20 day volume-weighted average closing price of

TC PipeLines, LP units of $36.26. For further information regarding the Share Ownership Guidelines, refer to the section Elements of Compensation - Share Ownership Guidelines , above.

Don Wishart

Executive Vice-President, Operations and Major Projects

Key Performance Accomplishments in 2009

- Exceptional leadership of operating and project management teams.
- Successful execution of major capital projects, including the successful completion of the construction of the first phase of the Keystone oil pipeline project.
- Top quartile safety, efficiency and reliability performance.
- Significant cost reductions throughout operations and in support functions.
- Effective operational integration of new assets and businesses.

AWARDED COMPENSATION	**2010 ($)**	**2009 ($)**	**2008 ($)**
FIXED			
Annual Base Salary(1)	600,000	550,000	550,000
VARIABLE			
Cash Bonus(2)	650,000	600,000	550,000
Performance Share Units(3)	1,087,500	1,014,000	900,000
Stock Options(4)	362,500	336,000	300,000
Total Direct Compensation	**2,700,000**	**2,500,000**	**2,300,000**
Change from previous year	+8%	+9%	-

2010 PAY MIX(5)

OWNERSHIP(6)

Minimum Ownership Level	**Minimum Ownership Value ($)**	**Total Ownership Value under the Guidelines ($)**	**Total Ownership as a Multiple of Base Salary**
2 x	1,100,000	2,998,645	5.5 x

(1) The annual base salary rate as at April 1st of the noted year.
(2) The total cash bonus awarded for performance attributable to the noted financial year, and paid in the first quarter following the completion of the financial year.
(3) The value of performance share units awarded during the annual granting process for the noted year.
(4) The compensation value of stock options granted during the annual granting process for the noted year.
(5) Pay mix is the resulting relative value of each compensation element following the allocation of Total Direct Compensation value and is expressed as a percentage of Total Direct Compensation.
(6)

Value of ownership determined as at December 31, 2009, using the 20 day volume-weighted average closing price of TransCanada s common shares of $35.36 and the 20 day volume-weighted average closing price of TC PipeLines, LP units of $36.26. For further information regarding the Share Ownership Guidelines, refer to the section Elements of Compensation - Share Ownership Guidelines , above.

PERFORMANCE GRAPH

The following chart compares TransCanada s five-year cumulative TSR to the S&P/TSX composite index (assuming reinvestment of dividends and considering a $100 investment on December 31, 2004 in TransCanada s common shares). The TSR analysis is superimposed on the aggregate Total Direct Compensation value awarded to the Executive Officers pursuant to the noted year.

As discussed throughout this section, the HR Committee and the Board consider a number of factors and performance elements when determining compensation for the Executive Officers. Although TSR is one performance measure that is reviewed, it is not the only consideration in executive compensation deliberations. As a result, a direct correlation between TSR over a given period and executive compensation levels is not necessarily anticipated. However, in the longer-term, the Executive Officers realized compensation is directly impacted by TransCanada s share price. A significant portion of their Total Direct Compensation is equity-based, which aligns award payouts with shareholder returns.

	Dec. 31, 2004	Dec. 31, 2005	Dec. 31, 2006	Dec. 31, 2007	Dec. 31, 2008	Dec. 31, 2009	Compound Annual Growth
	($)	($)	($)	($)	($)	($)	(%)
TransCanada	100	127.4	146.2	150.7	127.7	146.0	7.9
TSX	100	124.1	145.6	159.9	107.1	144.6	7.7

EXECUTIVE COMPENSATION TABLES

All compensation values disclosed in this section, unless otherwise noted, are expressed in Canadian dollars and are generally delivered from compensation plans and programs that are described in detail under the section above Compensation Discussion and Analysis or from retirement arrangements reported under the section below Pension and Retirement Benefits in this Proxy Circular.

The Executive Officers also serve as executive officers of TCPL. An aggregate remuneration is paid for serving as an executive of TransCanada and for service as an executive officer of TCPL. Since TransCanada does not hold any material assets directly other than the common shares of TCPL and receivables from certain of TransCanada s subsidiaries, all executive employee costs are assumed by TCPL according to a management services agreement between the two companies.

SUMMARY COMPENSATION TABLE

The following table outlines the summary of compensation received by the Executive Officers during or for the 2009, 2008, and 2007 financial years:

					Non-equity Incentive Plan Compensation				
Name and Principal Position (a)	**Year (b)**	**Salary(1) ($) (c)**	**Share-based Awards(2) ($) (d)**	**Option-based Awards(3) ($) (e)**	**Annual Incentive Plans(4) ($) (f1)**	**Long-term Incentive Plans(5) ($) (f2)**	**Pension Value(6) ($) (g)**	**All Other Compensation (7) ($) (h)**	**Total Compensation ($) (i)**
H.N. Kvisle	2009	1,250,004	3,040,000	960,000	1,650,000	628,875	157,000	12,500	7,698,379
President & Chief Executive	2008	1,237,503	3,000,000	1,000,000	1,850,000	702,000	753,000	12,354	8,554,857
Officer	2007	1,175,001	2,378,696	771,304	1,550,000	663,000	1,324,000	11,708	7,873,709
G.A. Lohnes	2009	430,008	584,000	216,000	600,000	70,950	7,000	4,300	1,912,258
Executive Vice-President &	2008	415,008	547,500	182,500	550,000	79,200	349,000	110,682	2,233,890
Chief Financial Officer	2007	362,508	422,878	137,122	490,000	104,742	181,000	158,061	1,856,311
R.K. Girling	2009	750,006	1,520,000	959,000	900,000	322,500	653,000	74,943	5,179,449
Chief Operating Officer	2008	682,506	1,500,000	500,000	950,000	396,000	352,000	6,796	4,387,302
	2007	602,502	1,261,088	408,912	900,000	408,220	594,000	5,979	4,180,702
A.J. Pourbaix	2009	700,008	1,520,000	480,000	740,000	206,400	11,000	58,458	3,715,866
President, Energy &	2008	682,506	1,500,000	500,000	900,000	255,600	343,000	66,796	4,247,902
Executive Vice-President Corporate Development	2007	602,502	1,261,088	408,912	900,000	241,400	575,000	61,479	4,050,381
D.M. Wishart	2009	550,008	1,014,000	336,000	650,000	161,250	43,000	26,500	2,780,758
Executive Vice-President,	2008	537,507	900,000	300,000	600,000	180,000	277,000	26,354	2,820,861
Operations & Major Projects	2007	475,005	755,143	244,857	550,000	204,220	467,000	46,708	2,742,934

(1) This column reflects actual base salary earnings during the noted financial year.

(2) This column shows the Total Direct Compensation value that was awarded as performance share units. The number of share units awarded is created by taking the value noted and dividing it by the valuation price at the time of grant, namely $32.98 for 2009, $39.87 for 2008, and $40.45 for 2007. The valuation price is based on the volume-weighted average closing price of TransCanada s common shares during the five trading days immediately prior to and including the grant date.

(3) This column shows the total compensation value of stock options awarded to the Executive Officers during each of the financial years noted. For 2007, the exercise price of a stock option granted to Canadian executives represented the volume-weighted closing price for the five trading days immediately preceding the grant. In 2008, the exercise price methodology was changed to represent the closing market price of TransCanada common shares on the TSX for the trading day immediately prior to the award date of the option. The exercise price of stock options granted to executives during the annual stock option granting process was $31.97 in 2009, $39.75 in 2008 and $38.10 in 2007.

In conjunction with his promotion to Chief Operating Officer, on September 14, 2009, the HR Committee awarded Mr. Girling a special grant of 100,000 stock options valued at $479,000 with an exercise price of $31.93. This grant was in addition to the grant of 100,000 stock options valued at $480,000 that Mr. Girling received earlier in the year during the annual stock option granting process.

(4) Amounts referred to in this column are paid as annual cash bonuses and are attributable to the noted financial year. These payments are generally made by March 15 in the year that follows the financial year.

(5) This column contains the value awarded from a grandfathered dividend-value plan under which grants are no longer made. The HR Committee and the Board determined an annual unit value of $1.29 per unit for 2009, $1.44 per unit for 2008, and $1.36 per unit for 2007 be awarded for all outstanding units held under the plan. Further information regarding this plan is noted in section Non-equity Long-term Incentive Plan , below.

(6) This column includes the annual compensatory value from the defined benefit pension plan. The annual compensatory value is the compensatory change in the accrued obligation and includes the service cost to TransCanada in 2009, plus compensation changes that were higher or lower than the salary assumption, and plan changes. Further explanation regarding the plan can be found in the section, Pension and Retirement Benefits for Executives - Defined Benefit Pension Plan below.

(7) The value in this column includes all other compensation not reported in any other column of the table for each of the Executive Officers and includes the following:

- The value of perquisites provided to Mr. Lohnes in 2007 was $47,891 which exceeded 10% of his total salary for that year and has therefore been included in this column. Other than this exception, the perquisites values for each Executive Officer for all other financial years listed are less than $50,000 and 10% of total salary and, as such, are not included in this column. For information, the average annual value for perquisites provided to the Executive Officers in 2009 was $30,061 or 4.7% of total salary. All perquisites provided to the Executive Officers have a direct cost to the Company and are valued on this basis.

- Mr. Lohnes was appointed Executive Vice-President and Chief Financial Officer for TransCanada in June 2006 and continued in his role as President of Great Lakes Transmission Company (Great Lakes) until September 1, 2006. Included in this column is a one-time special tax-protected cash payment of $200,000 made to Mr. Lohnes as part of his repatriation to Canada. This value was paid to Mr. Lohnes in annual installments of $70,000 in 2006, $65,000 in 2007 and $65,000 in 2008. The installments disclosed above include tax reimbursements of $41,557 for 2007 and $41,557 for 2008. Mr. Lohnes also received a tax reimbursement of $44,754 in 2006.

- Included in this column are payments made to Executive Officers by subsidiaries and affiliates of TransCanada (including directors fees paid by affiliates and amounts paid for serving on management committees of entities in which TransCanada holds an interest), specifically: Mr. Pourbaix - $57,000 for 2009, $60,000 for 2008, and $55,500 for 2007; and Mr. Wishart - $21,000 for both 2009 and 2008, and $42,000 for 2007.

- TransCanada s contributions under the Employee Stock Savings Plan made on behalf of the Executive Officer for the noted financial year is included in this column, specifically:

o Mr. Kvisle - $12,500 for 2009, $12,354 for 2008, and $11,708 for 2007;

o Mr. Lohnes - $4,300 for 2009, $4,125 for 2008, and $3,613 for 2007;

o Mr. Girling - $7,250 for 2009, $6,796 for 2008, and $5,979 for 2007;

o Mr. Pourbaix - $1,458 for 2009, $6,796 for 2008, and $5,979 for 2007; and

- Mr. Wishart - $5,500 for 2009, $5,354 for 2008, and $4,708 for 2007.

- Included in this column is the value of payments made in a particular financial year in the event an Executive Officer elected to receive a cash payment in lieu of vacation entitlement from the previous year.

Stock Option Valuation

The value disclosed in column (e) in the Summary Compensation Table, above, reflects the HR Committee s view of the grant date fair value of the stock option award. One month prior to each annual stock option grant, Towers Watson provides a binomial value for the upcoming grant based on their Expected Life Lattice Methodology which considers, among other things, the underlying share volatility, yield, as well as the vesting period and term of the option grant. The HR Committee used the higher of this binomial value or a floor-value of 15% of the exercise price to determine the value of each stock option for compensation purposes.

The following is a summary of the binomial value, floor value and the final compensation value underlying the amounts noted for the stock option grants in 2009, 2008 and 2007:

Grant Date	Exercise Price	Binomial Value from Towers Watson	Floor Value(1)	Compensation Value per Stock Option(2)
23-Feb-09	$31.97	$3.29	$4.80	**$4.80**
14-Sep-09(3)	$31.93	n/a	$4.79	**$4.79**
25-Feb-08	$39.75	$3.99	$5.96	**$5.96**
22-Feb-07	$38.10	$3.41	$3.81	**$3.81**

(1) With the assistance of the Consultant, the HR Committee sets floor value after considering a range of valuation approaches and assumptions, and ultimately using their discretion to arrive at a grant date fair value they deem to be fair and reasonable for compensation purposes. The floor value was set at 10% of the exercise price for 2007 and at 15% of the exercise price for 2008 and 2009.

(2) The Compensation Value for each stock option awarded under the grant is the higher of the Binomial Value from Towers Watson and the noted Floor Value.

(3) The HR Committee did not request a valuation from Towers Watson and applied the 15% floor value for this special grant to Mr. Girling.

For accounting purposes, the grant date fair values determined for the annual stock option awards using the Black-Scholes model were $5.48 per stock option for 2009, $3.97 per stock option for 2008, and $4.22 per stock option for 2007. The accounting value for the special stock option grant awarded to Mr. Girling on September 14, 2009 was $5.65.

Non-equity Long-term Incentive Plan

The values contained in column (f2) in the Summary Compensation Table, above, reflect the value awarded from a grandfathered dividend value plan under which grants are no longer made. Although no longer considered part of the current executive compensation program, annual awards on outstanding grants from this plan continue to be made and disclosed as compensation for the Executive Officers. Prior to the discontinuance of grants under the plan in 2003, one unit from the dividend-value plan was granted in tandem with each granted stock option and expired ten years from the date of grant.

Each dividend value plan unit provides the holder with the right to receive an annual unit value, as determined by the Board, in its discretion. The maximum annual unit value is equal to the dividends declared on one TransCanada common share in a given year. For 2009, the Board determined that $1.29 per unit (or 85% of the total declared dividend value in 2009) was to be awarded for all outstanding units held under the dividend value plan. The annual unit value awarded for 2009 and disclosed in column (f2) in the Summary Compensation Table, above, will be paid to each Executive Officer as a separate payment in March 2010.

INCENTIVE PLAN AWARDS OUTSTANDING OPTION-BASED AND SHARE-BASED AWARDS

The following table outlines all option-based and share-based awards previously awarded to the Executive Officers that are outstanding at the end of the most recently completed financial year.

	OPTION-BASED AWARDS				SHARE-BASED AWARDS	
Name (a)	**Number of Securities Underlying Unexercised Options (#) (b)**	**Option Exercise Price ($) (c)**	**Option Expiration Date (d)**	**Value of Unexercised In The Money Options(1) ($) (e)**	**Number of Shares or Units of Shares that have not Vested(2) (#) (f)**	**Market or Payout Value of Share-based Awards that have not Vested(3) ($) (g)**
H.N.					177,115	3,204,893
Kvisle	165,000	26.85	23-Feb-2011	1,541,100		
	42,500	18.01	27-Feb-2011	772,650		
	150,000	21.43	25-Feb-2012	2,214,000		
	160,000	30.09	28-Feb-2012	976,000		
	250,000	35.23	27-Feb-2013	240,000		
	202,442	38.10	22-Feb-2014	0		
	167,715	39.75	25-Feb-2015	0		
	200,000	31.97	23-Feb-2016	844,000		
G.A.					33,243	601,527
Lohnes	10,500	30.09	28-Feb-2012	64,050		
	14,000	35.23	27-Feb-2013	13,440		
	50,000	33.08	12-Jun-2013	155,500		
	35,990	38.10	22-Feb-2014	0		
	30,608	39.75	25-Feb-2015	0		
	45,000	31.97	23-Feb-2016	189,900		
R.K.					88,557	1,602,446
Girling	60,000	26.85	23-Feb-2011	560,400		
	65,000	21.43	25-Feb-2012	959,400		
	60,000	30.09	28-Feb-2012	366,000		
	90,000	35.23	27-Feb-2013	86,400		
	100,000	33.08	12-Jun-2013	311,000		
	107,326	38.10	22-Feb-2014	0		
	83,857	39.75	25-Feb-2015	0		
	100,000	31.97	23-Feb-2016	422,000		
	100,000	31.93	14-Sep-2016	426,000		
A.J.					88,557	1,602,446
Pourbaix	60,000	26.85	23-Feb-2011	560,400		

60,000	30.09	28-Feb-2012	366,000
90,000	35.23	27-Feb-2013	86,400
100,000	33.08	12-Jun-2013	311,000
107,326	38.10	22-Feb-2014	0
83,857	39.75	25-Feb-2015	0

	100,000	31.97	23-Feb-2016	422,000		
D.M. Wishart					56,346	1,019,575
	40,000	26.85	23-Feb-2011	373,600		
	35,000	18.01	27-Feb-2011	636,300		
	30,000	21.43	25-Feb-2012	442,800		
	40,000	30.09	28-Feb-2012	244,000		
	55,000	35.23	27-Feb-2013	52,800		
	64,267	38.10	22-Feb-2014	0		
	50,314	39.75	25-Feb-2015	0		
	70,000	31.97	23-Feb-2016	295,400		

(1) Calculated on outstanding vested and unvested stock options and based on the difference between the noted exercise price for the grant and the 2009 year-end closing price on the TSX for common shares of $36.19. For grants where the exercise price is higher than the year-end closing price, a zero value is noted.

(2) The number of units represents those from both the original grant and those added during the term as a result of dividend value reinvestment, from all outstanding grants of performance share units as at December 31, 2009.

(3) The plan under which performance share units are granted uses three-year performance objectives which can only be measured at the conclusion of the term. Additionally, there is no absolute formula applied to the performance results that is used to determine the final payout. Given that these conditions do not allow an interim calculation of performance results, the values noted in this column represent the minimum payout value from the plan that is greater than zero. This minimum payout value is calculated by taking 50% of the total units reported in column (f) and multiplying those by the 2009 year-end closing price on the TSX for common shares of $36.19.

INCENTIVE PLAN AWARDS VALUE VESTED DURING THE YEAR

The following table outlines the aggregate value of all option-based and share-based awards previously made to the Executive Officers that vested during the most recently completed financial year. It also includes the aggregate value from non-equity incentive plan awards that were earned by the Executive Officers during the most recently completed financial year.

Name	Option-based Awards Value Vested During the Year(1) ($)	Share-based Awards Value Vested During the Year(2) ($)	Non-equity Incentive Plan Compensation Value Earned During the Year(3) ($)
(a)	(b)	(c)	(d)
H.N. Kvisle	0	2,026,224	2,278,875
G.A. Lohnes	19,166	360,216	670,950
R.K. Girling	38,334	1,074,222	1,222,500
A.J. Pourbaix	38,334	1,074,222	946,400
D.M. Wishart	0	643,247	811,250

(1) Column (b) represents the aggregate dollar value that would have been realized by the Executive Officers if options had been exercised on the vesting date. Where the share price on the vesting date is lower than the exercise price of the grant a zero value is noted. Further details on this value are noted below in the section, Option-based Awards - Value Vested During the Year .

(2) The value noted in column (c) is the value paid to the Executive Officers upon the vesting of the 2007 grant of performance share units. Further details on this value are noted below in the section, Share-based Awards - Value Vested During the Year .

(3) The value noted is column (d) is the aggregate value from both the annual cash bonus payment and the dividend value plan annual payment that are attributable to this financial year. The annual cash bonus value is denoted in column (f1), Annual Incentive Plans while the dividend-value plan payment is denoted in column (f2), Long-term Incentive Plans in the Summary Compensation Table, above.

Option-based Awards Value Vested During the Year

The value noted in column (b) of the Value Vested During the Year table, above, is the aggregate value from outstanding stock options that vested during the financial year. The value represents the total dollar value that would have been realized if the stock options had been exercised on the vesting date. The following table provides grant-by-grant details on the calculation of this total value:

Supplemental Table Value of Outstanding Options Calculated at Vesting

Name	Grant Date	Total Number of Securities Under Options Granted (#)	Option Exercise Price ($)	Number of Options that Vested from the Grant during the Financial Year(1) (#)	Share Price on Vesting Date(2) ($)	Value at Vesting ($)
H.N.	25-Feb-08	167,715	39.75	55,905	30.50	0
Kvisle	22-Feb-07	202,442	38.10	67,481	31.97	0
	27-Feb-06	250,000	35.23	83,334	30.90	0
G.A.	25-Feb-08	30,608	39.75	10,203	30.50	0
Lohnes	22-Feb-07	35,990	38.10	11,997	31.97	0
	12-Jun-06	50,000	33.08	16,666	34.23	19,166
	27-Feb-06	14,000	35.23	4,666	30.90	0
R.K.	25-Feb-08	83,857	39.75	27,952	30.50	0
Girling	22-Feb-07	107,326	38.10	35,775	31.97	0
	12-Jun-06	100,000	33.08	33,334	34.23	38,334
	27-Feb-06	90,000	35.23	30,000	30.90	0
A.J.	25-Feb-08	83,857	39.75	27,952	30.50	0
Pourbaix	22-Feb-07	107,326	38.10	35,775	31.97	0
	12-Jun-06	100,000	33.08	33,334	34.23	38,334
	27-Feb-06	90,000	35.23	30,000	30.90	0
D.M.	25-Feb-08	50,314	39.75	16,771	30.50	0
Wishart	22-Feb-07	64,267	38.10	21,422	31.97	0
	27-Feb-06	55,000	35.23	18,334	30.90	0

(1) TransCanada employee stock options vest one-third on each anniversary of the grant date for a period of three years.

(2) The share price noted is the closing price for TransCanada Common Shares on the TSX for the later of the vesting date or the first full trading day following that date.

Share-based Awards Value Vested During the Year

The value noted in column (c) of the Value Vested During the Year table above is the value paid to the Executive Officers upon the vesting of the 2007 grant of performance share units. The noted value in this table is calculated as follows:

(1) The total number of units at the vesting date includes those both from the original grant and those accumulated by dividend-value reinvestment throughout the grant term.

(2) The Valuation Price equals the volume-weighted average trading price of TransCanada s common shares during the five trading days immediately prior to and including the vesting date.

(3) The Final Dividend value is the dividend per common share that has been declared as of Q4 of the vesting year but which has not been paid at the vesting date.

For information, the following table provides detail on the calculation of the performance share unit payment value that is noted in column (c) of the Value Vested During the Year table.

Supplemental Table Payment Value of 2007 Performance Share Unit Grant

Name	**Vesting Date**	**Total Units at Vesting (1) (#)**	**Value of Total Units at Vesting (2) ($)**	**Value of Final Dividend (3) ($)**	**Final Performance Multiplier (4)**	**Total Payment Value (5) ($)**
(i)	**(ii)**	**(iii)**	**(iv)**	**(v)**	**(vi)**	**(vii)**
H.N. Kvisle	31-Dec-09	65,941.706	2,358,735	25,058		2,026,224
G.A Lohnes	31-Dec-09	11,722.934	419,329	4,455		360,216
R.K. Girling	31-Dec-09	34,959.614	1,250,505	13,285	85%	1,074,222
A.J. Pourbaix	31-Dec-09	34,959.614	1,250,505	13,285		1,074,222
D.M. Wishart	31-Dec-09	20,933.914	748,806	7,955		643,247

(1) The total units at vesting include those units from the original grant and those from dividend reinvestment activity up to Q3 of 2009.

(2) Units noted in column (iii) were valued at $35.77 per unit based on the five day volume-weighted closing price of common shares on the TSX at December 31, 2009.

(3) The value noted is the declared dividend for Q4 2009 of $0.38 multiplied by the number of units noted in column (iii).

(4) Based on the HR Committee and the Board s assessment of the performance achieved against objectives, 85% of all units became vested for payment as of the Vesting Date noted.

(5) The value in this column represents the sum of the values from columns (iv) and (v) multiplied by the percentage in column (vi). This value was paid to the Executive Officers and all other plan participants in March 2010.

EQUITY COMPENSATION PLAN INFORMATION

Stock Option Plan

The Stock Option Plan is the only compensation arrangement under which equity securities of TransCanada have been authorized for issuance. Stock options may be granted to executive-level employees of TransCanada as approved by the HR Committee and described under the section, Compensation Decision-Making Process Stock Option Granting Process above.

On recommendation of the HR Committee, the Board has approved various amendments to the Stock Option Plan, some of which are subject to shareholder approval at the Meeting as described under the heading Business to be Transacted at the Meeting Reconfirmation of and Amendments to the Stock Option Plan . Key information regarding the Stock Option Plan is set forth below:

- The Stock Option Plan was first approved by shareholders in 1995;

- Shareholders are being asked at the Meeting to approve an increase in the number of shares issuable under the Stock Option Plan by 3,500,000;

- If the Stock Option Plan Resolution is approved, a maximum of 34,000,000 of TransCanada s common shares will have been reserved for issuance under the Plan since its inception in 1995; this represents 4.95% of common shares issued and outstanding as at February 26, 2010. As at February 26, 2010, there were approximately:

o 9,246,135 common shares issuable upon the exercise of outstanding stock options; this represents 1.3% of issued and outstanding common shares;

o 2,033,618 common shares remaining available for issuance; this represents 0.3% of issued and outstanding common shares;

o 19,190,997 common shares have been issued upon the exercise of stock options, representing 2.8% of issued and outstanding common shares of the Company;

- The exercise price of a stock option is the closing market price of a common share of TransCanada on the TSX on the last trading day immediately preceding the grant date of the stock option;
- Stock options granted after January 1, 2003 vest one-third on each of the following three anniversaries of the grant date and have a seven year term;
- If the expiry date of a stock option (i) does not fall during an open trading window or (ii) falls during the first five days of an open trading window, the expiry date of such stock option is extended for a total period of ten business days during the subsequent open trading window;
- Stock options cannot be transferred or assigned by participants, however, a personal representative is permitted to exercise stock options on behalf of the option holder in the case of death of an option holder or if an option holder is unable to manage his or her affairs; and
- The exercise price for unexercised issued stock options ranges from $10.03 to $39.75, with expiry dates ranging from February 28, 2010 to February 26, 2017.

Under the terms of the Stock Option Plan, the maximum number of common shares reserved for issuance as stock options to any one participant in any fiscal year cannot exceed 20% of the total number of options granted in that fiscal year. Additionally, the number of common shares that may be reserved for issuance to insiders, or issued to insiders within any one year period, under all of TransCanada s security based compensation arrangements cannot exceed 10% of TransCanada s issued and outstanding common shares. Other than these plan provisions, there are no additional restrictions on the number of stock options that may be granted to insiders.

The HR Committee has the authority to suspend or discontinue the Stock Option Plan at any time without shareholder approval. Management does not have a right to amend, suspend or discontinue the Stock Option Plan. The HR Committee may also make certain amendments to the plan or any stock option grant without shareholder approval, including such items as correcting any ambiguity, error or omission in the plan, changing the vesting date of a given grant and changing the expiry date of an outstanding stock option which does not entail an extension beyond the original expiry date. No amendments can be made to the Stock Option Plan that adversely affect the rights of any option holder regarding any previously granted options without the consent of the option holder.

The Stock Option Plan also provides that certain amendments be approved by the shareholders of TransCanada as provided by the rules of the TSX. Among other things, shareholder approval is required to increase the number of shares available for issuance under the Stock Option Plan, to lower the exercise price of a previously granted option, to cancel and reissue an option and to extend the expiry date of an option beyond its original expiry date.

In the event of a change of control, the HR Committee has discretion to accelerate vesting of the outstanding unvested options provided there is no agreement with the acquiring entity relating to the unvested options.

The following table outlines the action prescribed for grants under the Stock Option Plan. Unless a stock option expires earlier, as outlined below, stock options expire on the seventh anniversary of the date of the grant.

Event	Action
Death	All outstanding stock options vest and become exercisable as at the date of death and may be exercised no later than the first anniversary of the date of death.
Resignation	The participant may exercise outstanding vested and exercisable stock options no later than six months after the last day of active employment, after which date all outstanding stock options are forfeited. No options vest after the last day of active employment.

Retirement	All outstanding stock options vest and become exercisable as at the date of retirement and the participant may exercise these, and all other vested and exercisable stock options until the earlier of the expiry date or three years past the date of retirement.
Termination without cause	The participant may exercise outstanding vested and exercisable stock options no later than the later of the last day of the notice period and six months after the last day of active employment, after which date all outstanding stock options are forfeited. No options vest during the notice period.
Termination for cause	The participant may exercise outstanding vested and exercisable stock options no later than six months after the last day of active employment, after which date all outstanding stock options are forfeited. No options vest after the last day of active employment.

Securities Authorized for Issuance under Equity Compensation Plans

The following table outlines the number of common shares to be issued upon the exercise of outstanding stock options under the stock option plan, the weighted average exercise price of the outstanding stock options, and the number of common shares available for future issuance under the stock option plan, all as at December 31, 2009.

Plan Category	Number of securities to be issued upon exercise of outstanding options (#) (a)	Weighted-average exercise price of outstanding options ($) (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (#) (c)
Equity compensation plans approved by security holders	8,274,362	30.56	3,167,190
Equity compensation plans not approved by security holders	Nil	Nil	Nil
TOTAL	**8,274,362**	**30.56**	**3,167,190**

PENSION AND RETIREMENT BENEFITS

TransCanada s retirement program allows new employees and existing employees with less than ten years of service with TransCanada the choice to either participate permanently in the defined benefit pension plan or receive an annual Company contribution to the Company sponsored savings plan. Once an employee has ten years of service with the Company, participation in the defined benefit pension plan is mandatory. Eligible employees who elect to participate in the savings plan will receive a Company contribution equal to 7% of base salary plus 7% of annual incentive compensation paid up to a set percentage. Savings plan participants will have a choice annually between the defined benefit plan and the savings plan until they choose the defined benefit plan or they have ten years of service with the Company, whichever comes first. Savings plan participants do not accrue Credited Service (defined below) for the defined benefit plan while participating in the savings plan and are not entitled to carry over benefits accrued under the savings plan into the defined benefit pension plan.

All of the Executive Officers participate in the defined benefit pension plan.

Defined Benefit Pension Plan

The defined benefit pension plan consists of a base pension plan and a supplemental pension plan for eligible employees.

Base Pension Plan

All of TransCanada s Canadian employees with ten years of service and those with less than ten years of service who have elected to participate in the defined benefit pension plan (the Pension Plan Employees), including the Executive Officers, participate in the base pension plan, which is solely a non-contributory defined benefit pension plan. Employees may make optional pension contributions to an enhancement account to purchase ancillary or add-on defined benefit pension benefits within the pension plan.

The normal retirement age under TransCanada s base pension plan is age 60 or any age between 55 and 60 where the sum of an employee s age and continuous service equals 85. Employees are eligible to retire ten years prior to their normal retirement date, but the benefit payable is subject to early retirement reduction factors. For early retirement between ages 55 and 60, the reduction applied is 4.8 per cent for each year from the earlier of 85 points or age 60, and for retirement before age 55 the reduction applied is an actuarial equivalent from age 55. The defined benefit plan is integrated with Canada Pension Plan benefits.

The benefit calculation below provides the annual base pension payable at normal retirement:

1.25% of an employee s Highest Average Earnings(1) up to the Final Average(2) YMPE(3)	**plus**	1.75% of an employee s Highest Average Earnings above the Final Average YMPE	**multiplied by**	Credited Service(4)

(1) Highest Average Earnings means the average of an employee s best consecutive 36 months of Pensionable Earnings in the last 15 years before retirement. Pensionable Earnings means an employee s base salary plus the annual cash bonus up to a pre-established maximum amount expressed as a percentage of base salary (100% for CEO, 80% for COO, and 60% for Executive Officers) as outlined in the plan text for the defined benefit pension plan. Pensionable Earnings do not include any other forms of compensation.

(2) Final Average YMPE means the average of the year s maximum Pensionable Earnings in effect for the latest calendar year from which earnings are included in an employee s Highest Average Earnings calculation plus the two previous years.

(3) YMPE means Year s Maximum Pensionable Earnings under the Canada/Québec Pension Plan.

(4) Credited Service means the employee s years of credited pensionable service in the defined benefit pension plan.

Registered defined benefit pension plans are subject to a maximum annual benefit accrual under the *Income Tax Act* (Canada), which is currently $2,494 for each year of Credited Service, with the result that benefits cannot be earned in the base pension plan on compensation above approximately $156,000 per annum.

Supplemental Pension Plan

All of the Pension Plan Employees, including the Executive Officers, who have Pensionable Earnings over the *Income Tax Act* (Canada) ceiling of approximately $156,000 per year, participate in the Company s non-contributory defined benefit supplemental pension plan. Approximately 500 employees currently participate in the supplemental pension plan.

The defined benefit pension plan uses a hold harmless approach, where the maximum amount allowable under the *Income Tax Act* (Canada) will be paid from the base pension plan and the remainder is paid from the supplemental pension plan. The supplemental pension plan is funded through a retirement compensation arrangement under the *Income Tax Act* (Canada). Subject to the Board s approval, contributions to the fund are based on an annual actuarial valuation of the supplemental pension plan obligations calculated on the basis of the plan terminating at the beginning of each calendar year. The annual pension benefit under the supplemental pension plan is equal to 1.75% multiplied by the employee s Credited Service, multiplied by the amount by which such employee s Highest Average Earnings exceed the ceiling imposed under the *Income Tax Act* (Canada) and is recognized under the defined benefit pension plan.

Generally, neither the base pension plan nor the supplemental pension plan provide for the recognition of past service. However, pursuant to the provisions of the supplemental pension plan, the HR Committee has exercised its discretion to grant additional years of Credited Service to executive employees from time to time, in the past.

All Pension Plan Employees, including the Executive Officers, will receive the following normal form of pension:

(a) in respect of Credited Service prior to January 1, 1990, upon retirement, a monthly pension payable for life with 60% continuing thereafter to the employee s designated joint annuitant; and

(b) in respect of Credited Service on and after January 1, 1990, upon retirement, a monthly pension as described in (a) above for married employees or, for unmarried employees, a monthly pension payable for life with payments to the employee s estate guaranteed for the balance of ten years if the employee dies within ten years of retirement.

In lieu of the normal form of pension, optional forms of pension payment may be chosen provided that any legally required waivers are completed. Forms of optional pension payment include: increasing the percentage of the pension value that continues after death, adding a guarantee period to the pension and, under the base pension plan only, transferring the lump sum commuted value of the pension to a locked-in retirement account up to certain limits.

Accrued Pension Obligations

As at December 31, 2009, TransCanada s accrued obligation for the supplemental pension plan was approximately $193.9 million. The 2009 current service costs and interest costs of the supplemental pension plan were approximately $4.1 and $11.9 million, respectively, for a total of $16 million. The accrued pension obligation is calculated following the method prescribed by the Canadian Institute of Chartered Accountants and is based on management s best estimate of future events that affect the cost of pensions, including assumptions about future salary adjustments and bonuses. More information on the accrued obligations and the assumptions utilized may be found in Note 22 - (Employee Future Benefits) of the Notes to TransCanada s 2009 Consolidated Financial Statements which are available on the Company s website at www.transcanada.com and filed on SEDAR at www.sedar.com.

Defined Benefit Pension Plan Table

Name (a)	Number of Years of Credited Service (b)	Annual Benefits Payable (c) At Year End(4) ($) (c1)	Annual Benefits Payable (c) At Age 65(5) ($) (c2)	Accrued Obligation Start of Year(6) ($) (d)	Compensatory Change(7) ($) (e)	Non-Compensatory Change(8) ($) (f)	Accrued Obligation at Year End(6) ($) (g)
H.N. Kvisle(1)	20.33	823,000	1,149,000	8,662,000	157,000	1,561,000	10,380,000
G.A. Lohnes(2)	16.33	172,000	294,000	1,783,000	7,000	366,000	2,156,000
R.K. Girling(3)	14.00	243,000	556,000	2,046,000	653,000	583,000	3,282,000
A.J. Pourbaix(3)	14.00	239,000	601,000	1,823,000	11,000	578,000	2,412,000
D.M. Wishart	12.59	174,000	311,000	1,874,000	43,000	359,000	2,276,000

(1) In 2002, due to Mr. Kvisle s promotion to CEO, the HR Committee approved an arrangement to grant Mr. Kvisle additional Credited Service in recognition of his accomplishments to date and to retain his services into the future. The arrangement resulted in him receiving five years of additional Credited Service in 2004 on his fifth anniversary date with TransCanada. In addition, for each year after 2004, until and including 2009, Mr. Kvisle was granted one additional year of Credited Service on the date of the anniversary of his employment. All such additional service will not exceed ten additional years of Credited Service and is to be recognized solely in the supplemental pension plan with respect to earnings in excess of the maximum set under the *Income Tax Act* (Canada).

(2) Mr. Lohnes continued to accrue Credited Service in the base pension plan and supplemental pension plan while employed in the United States from August 16, 2000 to August 31, 2006. Pensionable Earnings were established on the basis that one U.S. dollar is equal to one Canadian dollar, and included both the U.S. base salary and annual cash bonus up to the pre-established maximum amount as outlined in the plan text for the defined benefit pension plan.

(3) In 2004, the HR Committee approved arrangements for Mr. Girling and Mr. Pourbaix to obtain additional Credited Service in recognition of their high potential and to retain their services into the future. Subject to Mr. Girling and Mr. Pourbaix maintaining continuous employment with TransCanada until September 8, 2007, each received an additional three years of Credited Service on that date which are to be recognized solely in the supplemental pension plan with respect to earnings in excess of the maximum set under the *Income Tax Act* (Canada).

(4) Column (c1) shows the annual lifetime benefit and is based on the years of Credited Service in column (b) and the actual Pensionable Earnings history as of December 31, 2009.

(5) Column (c2) shows the annual lifetime benefit at age 65 based on the years of Credited Service at age 65 and the actual Pensionable Earnings history as of December 31, 2009.

(6) The accrued obligation is the reported value of the pension obligations at December 31, 2008, shown in column (d), and December 31, 2009, shown in column (g), using actuarial assumptions and methods that are consistent with those used for calculating pension obligations as disclosed in the TransCanada s 2008 and 2009 consolidated financial statements. As the assumptions reflect TransCanada s best estimate of future events, the values shown in the above table may not be directly comparable to similar estimates of pension obligations that may be disclosed by other corporations.

(7) Column (e) shows the compensatory change in the accrued obligation and includes the service cost to TransCanada in 2009, plus compensation changes that were higher or lower than the salary assumption, and plan changes.

(8) Column (f) shows the non-compensatory change in the accrued obligation and includes the interest on the accrued obligation at the start of the year and changes in assumptions in the year.

TERMINATION AND CHANGE OF CONTROL BENEFITS

Separation Arrangements

Separation agreements with the Executive Officers (each, a Separation Agreement) outline the terms and conditions applicable in the event of an Executive Officer s separation from TransCanada due to retirement, termination (with or without cause), resignation, disability or death. The following table summarizes the material terms and provisions that apply under the noted separation events:

TYPE OF COMPENSATION			**SEPARATION EVENT**		
	RESIGNATION(1)	***TERMINATION WITHOUT CAUSE(2)***	***TERMINATION WITH CAUSE***	***RETIREMENT(3)***	***DEATH***
Base Salary	Payments cease	Severance allowance includes a lump-sum payment of annual base salary as of the separation date multiplied by the notice period(4)	Payments cease	Payments cease	Payments cease
Annual Bonus: Past Year	Not paid	Equals the Average Bonus(5) pro-rated by the number of months in the current year prior to the separation date	Not paid	Equals the Average Bonus(5) pro-rated by the number of months in the year prior to the separation date	Equals the Average Bonus(5) pro-rated by the number of months in the year prior to the separation date
Annual Bonus: Future Consideration	Not paid	A value based on the Average Bonus(5) multiplied by the notice period(3)	Not paid	Not paid	Not paid
Performance Share Units(6)	Vested units paid out; unvested units are forfeited	Vested units paid out; unvested units forfeited but originally granted value generally paid out on a *pro rata* basis	Vested units paid out; unvested units are forfeited	Vested units paid out; unvested units forfeited but originally granted value generally paid out on a *pro rata* basis	Vested units paid out; unvested units forfeited but originally granted value generally paid out on a *pro rata* basis
Stock Options	Vested options must be exercised by six months following separation; no options vest after the last day of active employment**(7)**	Vested options must be exercised by the later of the last day of the notice period**(4)** or six months following separation	Vested options must be exercised by six months following separation; no options vest after the last day of active employment(7)	All outstanding options vest and become exercisable; must be exercised by three years following retirement(8)	All outstanding options vest and become exercisable; must be exercised by the first anniversary of death(8)
Benefits	Coverage ceases or, if eligible, Retiree Benefits(9) commence	Coverage continues during notice period (or an equivalent lump-sum payout is made) and if eligible, service credit for the notice period(4) for Retiree Benefits(9)	Coverage ceases or, if eligible, Retiree Benefits(9) commence	Retiree Benefits(9) commence	Coverage ceases or, if eligible, Retiree Benefits(9) commence for a designated beneficiary

Pension	Paid as a commuted value or monthly benefit	Paid as a commuted value or monthly benefit(10)	Paid as a commuted value or monthly benefit	Paid as a commuted value or monthly benefit	Paid as a commuted value or monthly benefit
Perquisites	Payments cease	A lump-sum cash payment equal to the monthly corporate cost of the perquisite package multiplied by the notice period(4)	Payments cease	Payments cease	Payments cease

TYPE OF COMPENSATION	SEPARATION EVENT				
	RESIGNATION(1)	*TERMINATION WITHOUT CAUSE(2)*	*TERMINATION WITH CAUSE*	*RETIREMENT(3)*	*DEATH*
Other	- - -	Outplacement services	- - -	- - -	- - -

(1) Includes voluntary resignation but does not include resignation as a result of constructive dismissal.
(2) Includes treatment afforded to an Executive Officer in the event of an Executive Officer s resignation owing to constructive dismissal.
(3) If the Executive Officer becomes eligible for long term disability and the Company terminates the employment of the Executive Officer, the terms and provisions noted for retirement will apply.
(4) The notice period for the CEO is three years. For all other Executive Officers, the notice period is two years.
(5) The Average Bonus is equal to the average of the annual bonus amounts paid to the Executive Officer for the three years preceding the separation date.
(6) Reflects the terms and provisions that generally apply under the noted separation events, however, under the Executive Share Unit Plan pursuant to which performance share units are granted to executives, the HR Committee has the discretion to determine the treatment of unvested units on a case-by-case basis for executives subject to a Separation Agreement.
(7) For option grants prior to January 1, 2010, unvested options continue to vest until six months after the separation date in the event of resignation or termination without cause.
(8) The exercise provisions noted pertain to stock options granted after January 1, 2003. For stock options granted prior to that date, all outstanding stock options must be exercised within six months following the date of retirement or death.
(9) All employees are eligible for Retiree Benefits if, at the separation date, they are age 55 or over with 10 or more years of continuous service. These benefits include:
- a health spending account which can be used to pay for eligible health and dental expenses and/or to purchase private health insurance;
- a security plan, which provides a safety net in case of significant medical expenses; and
- life insurance, which provides a death benefit of $10,000 to a designated beneficiary.

All other coverage, including the employee stock plan, spousal and dependent life insurance, accident insurance, disability and payment of provincial health care premiums, end at the date of separation.
(10) Credited Service for the applicable notice period is provided at the end of the notice period.

TransCanada may elect to require Executive Officers to comply with a non-competition provision in the Separation Agreements for a period of 12 months from the Executive Officer s separation date. If TransCanada makes this election, a payment will be made to the Executive Officer of an amount equal to the annual base salary as of the separation date plus the Average Bonus.

Change of Control Arrangements

Under the Separation Agreements, a change of control is defined as including (but is not limited to) another entity becoming the beneficial owner of more than 20% of the voting shares of TransCanada or more than 50% of the voting shares of TCPL (not including the voting shares of TCPL held by TransCanada).

The following table summarizes the terms and provisions applicable to Executive Officers under the Separation Agreements in the event of a change of control.

Performance Share Units	If the Executive Officer s separation date is within two years of a change of control, all unvested performance share units are deemed vested and are paid out as a single, lump-sum cash payment.

Stock Options	Following a change of control, there is an acceleration of stock option vesting. If, for any reason, the Company is unable to implement this vesting acceleration (e.g., the Company s shares cease to trade), the Company will pay the Executive Officer a cash payment. This payment would be equal to the net amount of compensation the Executive Officer would have received if they had, on the date of a change of control, exercised all vested options and unvested options for which vesting would have been accelerated.

Pension	If the Executive Officer s separation date is within two years of a change of control, a pensionable service credit for the applicable notice period is provided at the date of separation rather than at the end of the notice period.

Additionally, the CEO may, in the month following the one year anniversary after a change of control, provide notice of his intention to leave TransCanada and in that event, he would receive all the same entitlements as if he had been terminated without cause.

Separation Payments

The following table provides a calculation of the separation payments that would have been made to the Executive Officers under the noted separation events with and without a deemed change of control. All payments are calculated assuming the date of separation was and, if applicable, a change of control occurred on December 31, 2009. The disclosed values represent payments made pursuant to the terms of the Separation Agreements and do not include certain values that would be provided under normal course, specifically the value of pension benefits normally provided following resignation and the value of Retiree Benefits.

	WITHOUT A CHANGE OF CONTROL			WITH A CHANGE OF CONTROL
Name(1)	**Payment Made in the Event of Termination with Cause(2) ($)**	**Payment Made in the Event of Termination Without Cause(3)(4) ($)**	**Payment Made in the Event of Retirement or Death ($)**	**Payment Made in the Event of Termination Without Cause Following a Change of Control(4)(5) ($)**
(a)	**(b)**	**(c)**	**(e)**	**(g)**
H.N. Kvisle	5,743,750	22,429,724	13,618,209	27,513,091
G.A. Lohnes	232,990	3,730,019	1,859,674	4,561,977
R.K. Girling	2,283,200	9,578,266	6,751,657	12,120,950
A.J. Pourbaix	1,323,800	8,310,675	5,349,590	10,427,358
D.M. Wishart	1,749,500	6,546,879	4,289,661	7,995,174

(1) Assuming all Executive Officers have a minimum 10 years of service as at the time of separation, Mr. Kvisle and Mr. Wishart would qualify for Retiree Benefits.
(2) Also constitutes treatment afforded an Executive Officer in the event of an Executive Officer s resignation without constructive dismissal.
(3) Also constitutes treatment afforded an Executive Officer in the event of an Executive Officer s resignation owing to constructive dismissal.
(4) In the event TransCanada elects to require an Executive Officer to comply with a non-competition provision as contained in the Separation Agreements, the Executive Officers would receive the following compensatory lump-sum payments:

- Mr. Kvisle - $2,883,337;
- Mr. Lohnes - $883,341;
- Mr. Girling - $1,650,004
- Mr. Pourbaix - $1,533,341; and
- Mr. Wishart - $1,100,008.

(5) Also constitutes treatment afforded an Executive Officer in the event of an Executive Officer s resignation owing to constructive dismissal where separation date is within two years from the date of the change of control.

The aggregate value of perquisites for each Executive Officer is less than $50,000 or 10% of salary and as such, has been excluded from the separation payment calculations. As applicable to the provisions for certain separation events, the values from share-based compensation incorporate the following assumptions:

- applicable payments from outstanding performance share unit grants inclusive of additional units from dividend reinvestment up to and including the last quarter of 2009 and assuming a value of $35.77 per unit which is the five-day volume-weighted average closing share price on the TSX of TransCanada s common shares as of December 31, 2009; and
- the value of vested in-the-money stock options, assumed exercised as at the separation date and using an exercise price of $36.19 which is

based on the closing share price on the TSX of TransCanada s common shares on December 31, 2009.

The HR Committee annually reviews severance payment amounts for each of the Executive Officers as calculated under the Separation Agreements. The data provided to the HR Committee represents the total value to be paid to the Executive Officer in the event of termination without cause, both with and without a deemed change of control as well as the additional payment that could be made under the non-competition provision.

Financial Highlights

Year ended December 31 *(millions of dollars)*	**2009**	2008	2007	2006	2005
Income					
Net income applicable to common shares					
Continuing operations	**1,357**	1,420	1,210	1,049	1,208
Discontinued operations				28	
	1,357	1,420	1,210	1,077	1,208
Cash Flow					
Funds generated from operations	**3,044**	2,992	2,603	2,374	1,950
(Increase)/decrease in operating working capital	**(88)**	128	63	(503)	79
Net cash provided by continuing operations	**2,956**	3,120	2,666	1,871	2,029
Capital expenditures and acquisitions	**6,319**	6,363	5,874	2,042	2,071
Balance Sheet					
Total assets	**44,670**	40,735	31,737	26,386	24,113
Long-term debt	**16,186**	15,368	12,377	10,887	9,640
Junior subordinated notes	**1,036**	1,213	975		
Common shareholders' equity	**14,483**	12,574	9,664	7,618	7,164

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Management's Discussion and Analysis (MD&A) dated February 22, 2010 should be read in conjunction with the accompanying audited Consolidated Financial Statements of TransCanada PipeLines Limited (TCPL or the Company) and the notes thereto for the year ended December 31, 2009 which are prepared in accordance with Canadian generally accepted accounting principles (GAAP). This MD&A covers TCPL's financial position and operations as at and for the year ended December 31, 2009. "TCPL" or "the Company" includes TransCanada PipeLines Limited and its subsidiaries unless otherwise indicated. Amounts are stated in Canadian dollars unless otherwise indicated. Abbreviations and acronyms not defined in this MD&A are defined in the Glossary of Terms in the Company's 2009 Annual Report.

TCPL OVERVIEW

At December 31, 2009, TCPL had completed approximately $10 billion of its $22 billion capital program. Upon completion of this program, these assets are expected to generate additional annual earnings before interest, taxes, depreciation and amortization (EBITDA) of approximately $2.5 billion. The Company expects to complete most of the projects in its capital growth program by the end of 2013. Over the longer term, TCPL intends to continue to develop its substantial asset portfolio and pursue other large-scale pipeline and energy infrastructure projects. TCPL is committed to maintaining the financial strength required to invest in the development of North American energy infrastructure and respond to shifting energy supply-demand dynamics.

TCPL's 2009 Key Accomplishments

- Acquired ConocoPhillips' remaining interest in Keystone, increasing TCPL's ownership to 100 per cent;
- completed the first phase of construction of Keystone to Wood River and Patoka, Illinois;
- entered into an arrangement with ExxonMobil to jointly develop the Alaska pipeline and, in January 2010, filed a plan to obtain approval to conduct the first natural gas pipeline open season to develop Alaska's vast natural gas resources;
- Portlands Energy and the first phase of Kibby Wind were placed into service; and
- issued approximately $6 billion of debt and equity during a challenging North American economic environment.

Pipelines Assets

The TCPL pipeline network, including assets under construction and development, consists of more than 60,000 kilometres (km) (37,000 miles) of wholly owned and 8,800 km (5,468 miles) of partially owned natural gas pipelines and transports 20 per cent of the natural gas consumed in North America. TCPL's natural gas pipelines link gas supplies from Western Canada, the United States (U.S.) mid-continent and Gulf of Mexico to premium North American markets. These assets are well positioned to connect emerging natural gas supplies, including northern gas, northeastern British Columbia (B.C.) and U.S. shale gas, Rocky Mountain gas and offshore liquefied natural gas (LNG) imports, to growing markets.

TCPL's Alberta System gathered 66 per cent of the natural gas produced in Western Canada or 14 per cent of total North American production in 2009. TCPL transports natural gas from the Western Canada Sedimentary Basin (WCSB) to Eastern Canada and the U.S. West, Midwest, and Northeast through three wholly owned pipeline systems: the Canadian Mainline, GTN and Foothills. TCPL also transports natural gas from the WCSB to Eastern Canada and to the U.S. West, Midwest and Northeast through six partially owned natural gas pipeline systems: Great Lakes, Iroquois, Portland, TQM, Northern Border and Tuscarora. Certain of these pipeline systems are held through the Company's 38.2 per cent interest in TC PipeLines, LP (PipeLines LP).

ANR transports natural gas from producing fields located primarily in Texas, Oklahoma, the Gulf of Mexico and Louisiana to markets located in Wisconsin, Michigan, Illinois, Ohio and Indiana. It also connects with numerous other natural gas pipelines, providing customers with access to diverse sources of North American supply, including Western Canada and the Rocky Mountain region, and to a variety of end-user markets in the midwestern and northeastern U.S. ANR owns and operates 250 billion cubic feet (Bcf) of regulated natural gas storage capacity in Michigan. TCPL also serves natural gas markets in Mexico through its Tamazunchale and North Baja pipelines, and will expand service to markets in Mexico with the Guadalajara pipeline which is under construction.

In addition, TCPL is constructing the approximately 6,200 km (3,853 miles) Keystone crude oil pipeline. Keystone is expected to transport 1.1 million barrels per day (Bbl/d) of crude oil from Hardisty, Alberta to U.S. Midwest markets at Wood River and Patoka, Illinois, and to Cushing, Oklahoma, and to U.S. Gulf Coast markets. The pipeline will provide a low-cost shipping option to customers and is supported by long-term contracts with creditworthy counterparties. The first phase of Keystone, which is to Wood River and Patoka, is expected to commence delivery of crude oil in mid-2010 with the remaining phases expected to commence service in first quarter 2011 and first quarter 2013. In the medium to long term, opportunities for further additions to Keystone would expand the pipeline's transport capacity to 1.5 million Bbl/d from 1.1 million Bbl/d.

Energy Assets

TCPL's Energy business has grown to more than 11,700 megawatts (MW) in 2009 from 754 MW in 1999, including assets under construction and development. The Company's diverse power generation portfolio of primarily low-cost, base load and long-term contracted facilities comprises a total of 20 plants in Alberta, Arizona, Eastern Canada, New England and New York City.

TCPL's Western Power business comprises approximately 2,600 MW of power supply in Alberta and the western U.S. The Western Power portfolio in Alberta consists of three long-term power purchase arrangements (PPA): the Sheerness and Sundance A and B coal-fired plants, and five natural gas-fired cogeneration facilities consisting of MacKay River, Carseland, Bear Creek, Redwater and Cancarb. The Sundance A PPA expires in 2017 and the Sundance B and Sheerness PPAs expire in 2020. The other power facility in the Western Power portfolio is Coolidge, a natural gas-fired peaking facility under construction in Arizona whose output will be sold under a 20 year PPA. Coolidge is expected to be in service in second quarter 2011. Western Power's marketing business serves an integral function by purchasing and reselling electricity and natural gas to maximize the return from the Western Power assets.

The Eastern Power business is comprised of approximately 2,900 MW of power generation capacity, including facilities under construction. Eastern Power's operating assets consist of Bécancour, three of five Cartier Wind farms, Portlands Energy and Grandview. Power from Bécancour and Cartier Wind is sold to Hydro-Québec through 20 year power purchase contracts. Output from the Portlands Energy and Grandview facilities is sold through 20 year contracts with the Ontario Power Authority (OPA) and Irving Oil Limited (Irving), respectively. Halton Hills and the remaining two Cartier Wind farms which are under construction are expected to be in service in 2010, 2011 and 2012, respectively. Oakville, which is currently under development, is expected to be in service in first quarter 2014. Once operational, Oakville and Halton Hills will sell power to the OPA through 20 year contracts and the remaining two Cartier Wind farms will sell power to Hydro-Québec through 20 year contracts.

TCPL has a 48.8 per cent interest in Bruce A and a 31.6 per cent interest in Bruce B, which together comprise the Bruce Power nuclear generating facility. Bruce A has four 750 MW reactors, two of which are being refurbished, and Bruce B has four operational reactors with a combined capacity of 3,200 MW. Through a contract with the OPA, all of the output from Bruce A is effectively sold at a fixed price and the output from Bruce B is subject to a floor price.

TCPL's U.S. Power assets have approximately 3,800 MW of power generation capacity, including facilities under construction. The operating assets in the U.S. Power portfolio consist of Ravenswood, TC Hydro, OSP and phase one of Kibby Wind. Phase two of Kibby Wind is under construction and is expected to be placed into service in third quarter 2010. U.S. Power sells power to wholesale, commercial and industrial customers through TransCanada Power Marketing Ltd. (TCPM), a wholly owned subsidiary of TCPL.

The accompanying graph illustrates each fuel source as a percentage of the Company's overall Energy portfolio:

TCPL has developed a significant non-regulated natural gas storage business in Alberta where the Company owns or has rights to 129 Bcf or approximately one-third of natural gas storage capacity in the province.

TCPL'S STRATEGY

TCPL's vision is to be the leading energy infrastructure company in North America, focusing on pipelines and power generation opportunities in regions where it has or can develop a significant competitive advantage. TCPL's key strategies continue to evolve with the Company's growth and development and its changing business environment. TCPL's corporate strategy integrates five fundamental value-creating activities:

1. Maximize the full-life value of TCPL's infrastructure assets and commercial positions
2. Cultivate a focused portfolio of high quality development options
3. Commercially develop and physically execute new asset investment programs
4. Maximize TCPL's competitive strengths
5. Maximize TCPL's reputation and standing in financial markets

Maximize the full-life value of TCPL's infrastructure assets and commercial positions

TCPL relies on a low-risk business model to maximize the full-life value of its existing assets and commercial positions. In Pipelines, large scale natural gas and crude oil pipelines connect long life supply basins with stable and growing markets, generating predictable, sustainable cash flows and earnings of a long term nature. In Energy, highly efficient large scale power generation facilities supply power markets through long term power purchase and sale agreements and low-volatility shorter term commercial arrangements. TCPL's growing investments in natural gas, nuclear, wind and hydro generating facilities demonstrate the Company's commitment to sustainable, clean energy. Long-life infrastructure assets and long term commercial arrangements will continue as cornerstones of TCPL's business model.

Cultivate a focused portfolio of high quality development options

The Company's core regions within North America are the primary focus of growth initiatives in Pipelines and Energy. TCPL will continue to pursue opportunities to connect long-life shale and conventional gas resources in western Canada, northern Canada, Alaska, U.S. Rockies, U.S. midcontinent and Gulf Coast supply regions. TCPL will continue to pursue opportunities to connect growing crude oil volumes from the Alberta oilsands to preferred North American markets. The Company will continue to assess pipeline acquisition opportunities that complement its existing pipeline networks and provide access to new supply and market regions. In Energy, the Company will continue to focus on low-cost, long-life base load power generating and natural gas storage assets supported by firm, long-term contracts with reputable counterparties. Selected opportunities will move forward to full development and construction when market conditions are appropriate and project risks are manageable.

Commercially develop and physically execute new asset investment programs

TCPL expects to substantially complete construction of assets under its current $22 billion capital program by the end of 2013. The Company is focused on completing its capital projects on time and on budget, enabling it to meet commitments to customers and to deliver attractive, long-term returns to shareholders. The current capital program is characterized by highly contracted, long-term revenue streams with limited exposure to commodity prices. Capital cost risks are managed by TCPL's strong and experienced project management teams and industry-leading project management practices.

Maximize TCPL's competitive strengths

TCPL continues to build competitive strength in areas that directly drive long-term shareholder value. The Company relies on its scale, presence, operating capabilities, strong leadership and capable teams to compete effectively and deliver outstanding value to its customers. A disciplined approach to capital investment combined with a low cost of capital allows the Company to create significant shareholder value from large capital projects. TCPL recognizes that constructive relationships with key customers and stakeholders are critically important in the long-term energy infrastructure business. The Company continues to identify and build on all aspects of competitive strength.

Maximize TCPL's reputation and standing in financial markets

TCPL values its reputation for consistent financial performance and long term financial stability. The Company clearly communicates its financial performance to its investors, providing insight into both value upside and business risks. The Company works to sustain the trust and support of its long-term investors and to attract new investors who see long term value in a disciplined approach to the energy infrastructure business.

CONSOLIDATED FINANCIAL REVIEW

SELECTED THREE YEAR CONSOLIDATED FINANCIAL DATA
(millions of dollars, except per share amounts)

	2009	2008	2007
Income Statement			
Revenues	**8,966**	8,619	8,828
Comparable EBITDA[1]	**4,107**	4,125	3,919
Comparable EBIT[1]	**2,730**	2,878	2,682
EBIT[1]	**2,760**	3,133	2,708
Net income	**1,379**	1,442	1,232
Preferred share dividends	**22**	22	22
Net income applicable to common shares	**1,357**	1,420	1,210
Comparable earnings[1]	**1,308**	1,259	1,087
Per Common Share Data			
Net income per share Basic and Diluted	**$2.20**	$2.59	$2.33
Cash Flows			
Funds generated from operations[1]	**3,044**	2,992	2,603
(Increase)/decrease in operating working capital	**(88)**	128	63
Net cash provided by operations	**2,956**	3,120	2,666
Capital expenditures	**5,417**	3,134	1,651
Acquisitions, net of cash acquired	**902**	3,229	4,223
Balance Sheet			
Total assets	**44,670**	40,735	31,737
Total long-term liabilities	**24,065**	21,809	17,832

(1) Refer to the Non-GAAP Measures section of this MD&A for further discussion of comparable EBITDA, comparable EBIT, EBIT, comparable earnings, and funds generated from operations.

HIGHLIGHTS

Earnings

Net income was $1,379 million and net income applicable to common shares was $1,357 million compared to $1,442 million and $1,420 million, respectively, in 2008.

TCPL's comparable earnings of $1,308 million in 2009 excluded an after tax dilution gain of $18 million resulting from the Company's reduced interest in PipeLines LP and $30 million of favourable income tax adjustments. Comparable earnings of $1,259 million in 2008 excluded $152 million of after tax gains from bankruptcy settlements with certain subsidiaries of Calpine Corporation (Calpine), proceeds of $10 million after tax from a lawsuit settlement, a $27 million after tax writedown of costs for the Broadwater LNG project and $26 million of favourable income tax adjustments.

Cash Flow

Funds generated from operations were $3.0 billion in 2009, an increase of $0.1 billion from 2008.

TCPL invested $6.3 billion in its Pipelines and Energy capital projects in 2009, including the following:

- Capital expenditures of $3.9 billion for Pipelines projects, including construction of Keystone and the Bison pipeline project, and expansion of the Alberta System;
- capital expenditures of $1.5 billion for Energy projects, including the refurbishment and restart of Bruce A Units 1 and 2, and construction of Kibby Wind, Halton Hills, and Coolidge; and
- acquisition of ConocoPhillips' remaining interest in Keystone for $0.9 billion.

In 2009, TCPL issued approximately $3.3 billion of long-term debt and $1.7 billion of common shares, comprised primarily of the following:

- in 2009, the issuance of 52 million common shares resulting in proceeds of $1.7 billion;
- in February 2009, the issuance of $0.7 billion of Medium-Term Notes; and
- in January 2009, the issuance of US$2.0 billion of Senior Unsecured Notes.

In December 2009, TCPL established a new US$1.0 billion committed bank facility.

In November 2009, PipeLines LP issued five million common units at US$38.00 per unit, resulting in gross proceeds of US$0.2 billion.

Balance Sheet

Total assets increased by $3.9 billion to $44.7 billion in 2009 compared to 2008, primarily due to investments in Pipelines and Energy capital projects.

TCPL's shareholders' equity increased by $1.9 billion to $14.9 billion in 2009 compared to 2008.

Dividends

On February 22, 2010, the Board of Directors of TCPL declared a dividend for the quarter ending March 31, 2010 in an aggregate amount equal to the quarterly dividend to be paid on TransCanada Corporation's (TransCanada), issued and outstanding common shares at the close of business on March 31, 2010. The Board also declared regular dividends on TCPL's preferred shares.

Refer to the Consolidated Financial Review, Results of Operations and Liquidity and Capital Resources sections of this MD&A for further discussion of these highlights.

SEGMENT RESULTS

Effective January 1, 2009, TCPL revised the information presented in the tables of this MD&A to better reflect the operating and financing structure of the Company. The Pipelines and Energy results summaries are presented geographically by separating the Canadian and U.S. portions of each segment. The Company believes this new format more clearly describes the financial performance of its businesses. The new format presents EBITDA and earnings before interest and taxes (EBIT), which the Company believes provide greater transparency and more useful information with respect to the performance of its individual assets. Segmented information has been retroactively reclassified to reflect these changes. These changes had no impact on reported consolidated net income applicable to common shares.

Reconciliation of Comparable EBITDA, Comparable EBIT, EBIT and Comparable Earnings to Net Income Applicable to Common Shares

Year ended December 31, 2009 *(millions of dollars)*	Pipelines	Energy	Corporate	Total
Comparable EBITDA[1]	**3,093**	**1,131**	**(117)**	**4,107**
Depreciation and amortization	**(1,030)**	**(347)**		**(1,377)**
Comparable EBIT[1]	**2,063**	**784**	**(117)**	**2,730**
Specific items:				
Dilution gain from reduced interest in PipeLines LP	**29**			**29**
Fair value adjustments of natural gas inventory in storage and forward contracts		**1**		**1**
EBIT[1]	**2,092**	**785**	**(117)**	**2,760**
Interest expense				**(986)**
Interest expense of joint ventures				**(64)**
Interest income and other				**119**
Income taxes				**(376)**
Non-controlling interests				**(74)**
Net Income				**1,379**
Preferred share dividends				**(22)**
Net Income Applicable to Common Shares				**1,357**
Specific items (net of tax where applicable):				
Dilution gain from reduced interest in PipeLines LP				**(18)**
Fair value adjustments of natural gas inventory in storage and forward contracts				**(1)**
Income tax adjustments				**(30)**
Comparable Earnings[1]				**1,308**

Year ended December 31, 2008 *(millions of dollars)*	Pipelines	Energy	Corporate	Total
Comparable EBITDA[1]	3,019	1,210	(104)	4,125
Depreciation and amortization	(989)	(258)		(1,247)
Comparable EBIT[1]	2,030	952	(104)	2,878
Specific items:				
Calpine bankruptcy settlements	279			279
GTN lawsuit settlement	17			17
Writedown of Broadwater LNG project costs		(41)		(41)
EBIT[1]	2,326	911	(104)	3,133
Interest expense				(962)
Interest expense of joint ventures				(72)
Interest income and other				42
Income taxes				(591)
Non-controlling interests				(108)
Net Income				1,442
Preferred share dividends				(22)
Net Income Applicable to Common Shares				1,420
Specific items (net of tax where applicable):				
Calpine bankruptcy settlements				(152)
GTN lawsuit settlement				(10)
Writedown of Broadwater LNG project costs				27
Income tax adjustments				(26)
Comparable Earnings[1]				1,259

Year ended December 31, 2007 *(millions of dollars)*	Pipelines	Energy	Corporate	Total
Comparable EBITDA[1]	3,077	944	(102)	3,919
Depreciation and amortization	(1,021)	(216)		(1,237)
Comparable EBIT[1]	2,056	728	(102)	2,682
Specific items:				
Gain on sale of land		16		16
Fair value adjustments of natural gas inventory in storage and forward contracts		10		10
EBIT[1]	2,056	754	(102)	2,708
Interest expense				(961)
Interest expense of joint ventures				(75)
Interest income and other				118
Income taxes				(483)
Non-controlling interests				(75)
Net Income				1,232
Preferred share dividends				(22)
Net Income Applicable to Common Shares				1,210
Specific items (net of tax where applicable):				
Gain on sale of land				(14)
Fair value adjustments of natural gas inventory in storage and forward contracts				(7)
Income tax adjustments				(102)
Comparable Earnings[1]				1,087

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of comparable EBITDA, comparable EBIT, EBIT, and comparable earnings.

RESULTS OF OPERATIONS

In 2009, net income applicable to common shares was $1,357 million compared to net income applicable to common shares of $1,420 million in 2008. Net income applicable to common shares in 2007 was $1,210 million.

Net income applicable to common shares in 2009 included $30 million of favourable income tax adjustments arising from a reduction in the Province of Ontario's corporate income tax rates, an $18 million after tax dilution gain resulting from TCPL's reduced interest in PipeLines LP after a public offering of PipeLines LP common units in fourth quarter 2009, and $1 million of after tax net unrealized gains (2008 nil; 2007 net gains of $7 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

Net income applicable to common shares in 2008 included $152 million of after tax gains on shares received by GTN and Portland from the Calpine bankruptcy settlements, $10 million after tax of GTN lawsuit settlement proceeds and a $27 million after tax writedown of costs previously capitalized for Broadwater. Net income in 2008 also included $26 million of favourable income tax adjustments from an internal restructuring and realization of losses. Net income applicable to common shares in 2007 included $102 million of favourable income tax adjustments relating to changes in Canadian federal and provincial corporate income tax legislation, the resolution of certain tax matters and an internal restructuring, and an after tax gain of $14 million on the sale of land.

Comparable earnings in 2009, 2008 and 2007 were $1,308 million, $1,259 million and $1,087 million, respectively, and excluded the above-noted items.

Comparable earnings increased $49 million in 2009 compared to 2008. The increase in comparable earnings reflected:

- Increased comparable EBIT from Pipelines primarily due to higher earnings from the Alberta System revenue requirement settlement and the positive impact in 2009 of a stronger U.S. dollar on Pipelines' U.S. operations, partially offset by increased costs for developing new Pipelines projects, primarily the Alaska pipeline project;

- decreased comparable EBIT from Energy primarily due to lower power prices and a decreased demand for power in Western Power and U.S. Power, reflecting the downturn in the North American economy, partially offset by increased earnings from the start up of Portlands Energy and the Carleton phase of the Cartier Wind project, and higher realized power prices for Bruce Power;

- increased comparable EBIT losses from Corporate primarily due to higher support services costs, reflecting a growing asset base;

- increased interest expense as a result of long-term debt issuances in the second half of 2008 and first quarter 2009 and the negative impact of a stronger U.S. dollar. These increases were partially offset by an increase in capitalized interest relating to Keystone and other capital projects, and reduced losses from changes in the fair value of derivatives used to manage TCPL's exposure to fluctuating interest rates;

- increased interest income and other due to the positive impact of a weakening U.S. dollar on U.S. dollar working capital balances throughout 2009 and derivatives used to manage the Company's exposure to foreign exchange rate fluctuations;

- decreased income tax expense due to lower pre-tax earnings, higher income tax savings from income tax rate differentials and other positive income tax adjustments in 2009; and

- a reduction in non-controlling interests due to Portland's portion of the Calpine bankruptcy settlements recorded in 2008, partially offset by higher PipeLines LP earnings in 2009.

Comparable earnings increased $172 million in 2008 compared to 2007 due to an increase in Energy's comparable EBIT, primarily as a result of higher realized power prices and a full year of earnings from ANR, partially offset by unrealized losses from changes in the fair value of interest rate derivatives.

Results from each of the segments are discussed further in the Pipelines, Energy and Corporate sections of this MD&A.

FORWARD-LOOKING INFORMATION

This MD&A may contain certain information that is forward looking and is subject to important risks and uncertainties. The words "anticipate", "expect", "believe", "may", "should", "estimate", "project", "outlook", "forecast" or other similar words are used to identify such forward-looking information. Forward-looking statements in this document are intended to provide TCPL security holders and potential investors with information regarding TCPL and its subsidiaries, including management's assessment of TCPL's and its subsidiaries' future financial and operational plans and outlook. Forward-looking statements in this document may include, among others, statements regarding the anticipated business prospects and financial performance of TCPL and its subsidiaries, expectations or projections about the future, strategies and goals for growth and expansion, expected and future cash flows, costs, schedules, operating and financial results and expected impact of future commitments and contingent liabilities. All forward-looking statements reflect TCPL's beliefs and assumptions based on information available at the time the statements were made. Actual results or events may differ from those predicted in these forward-looking statements. Factors that could cause actual results or events to differ materially from current expectations include, among others, the ability of TCPL to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the operating performance of the Company's pipeline and energy assets, the availability and price of energy commodities, capacity payments, regulatory processes and decisions, changes in environmental and other laws and regulations, competitive factors in the pipeline and energy sectors, construction and completion of capital projects, labour, equipment and material costs, access to capital markets, interest and currency exchange rates, technological developments and economic conditions in North America. By its nature, forward-looking information is subject to various risks and uncertainties, including those material risks discussed in the Pipelines, Energy and Risk Management and Financial Instruments sections in this MD&A, which could cause TCPL's actual results and experience to differ materially from the anticipated results or expectations expressed. Additional information on these and other factors is available in the reports filed by TCPL with Canadian

securities regulators and with the U.S. Securities and Exchange Commission (SEC). 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 not to use future-oriented information or financial outlooks for anything other than their intended purpose. TCPL undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

NON-GAAP MEASURES

TCPL uses the measures "comparable earnings", "comparable EBITDA", "EBIT", "comparable EBIT" and "funds generated from operations" in this MD&A. These measures do not have any standardized meaning prescribed by GAAP. They are, therefore, considered to be non-GAAP measures and may not be comparable to similar measures presented by other entities. Management of TCPL uses these non-GAAP measures to improve its ability to compare financial results among reporting periods and to enhance its understanding of operating performance, liquidity and ability to generate funds to finance operations. These non-GAAP measures are also provided to readers as additional information on TCPL's operating performance, liquidity and ability to generate funds to finance operations.

EBITDA is an approximate measure of the Company's pre-tax operating cash flow. EBITDA comprises earnings before deducting interest and other financial charges, income taxes, depreciation and amortization, and non-controlling interests. EBIT is a measure of the Company's earnings from ongoing operations. EBIT comprises earnings before deducting interest and other financial charges, income taxes and non-controlling interests.

Management uses the measures of comparable earnings, comparable EBITDA and comparable EBIT to better evaluate trends in the Company's underlying operations. Comparable earnings, comparable EBITDA and comparable EBIT comprise net income applicable to common shares, EBITDA and EBIT, respectively, adjusted for specific items that are significant but are not reflective of the Company's underlying operations in the year. Specific items are subjective, however, management uses its judgement and informed decision-making when identifying items to be excluded in calculating comparable earnings, comparable EBITDA and comparable EBIT, some of which may recur. Specific items may include but are not limited to certain income tax refunds and adjustments, gains or losses on sales of assets, legal and bankruptcy settlements, and certain fair value adjustments. The Segment Results table in this MD&A presents a reconciliation of comparable earnings, comparable EBITDA, comparable EBIT and EBIT to net income and net income applicable to common shares.

Funds generated from operations comprises net cash provided by operations before changes in operating working capital. A reconciliation of funds generated from operations to net cash provided by operations is presented in the Summarized Cash Flow table in the Liquidity and Capital Resources section of this MD&A.

OUTLOOK

TCPL's corporate strategy is underpinned by long-term growth, focusing on its core strengths in its Pipelines and Energy businesses. In 2010 and beyond, TCPL expects net income and operating cash flow, combined with a strong balance sheet and proven ability to access capital markets, to provide the financial resources needed to complete its current capital expenditure program, continue to pursue long-term growth opportunities and create additional value for its shareholders. This strategy will be executed with the same discipline and deliberate manner that have characterized TCPL's current capital expenditure program. TCPL believes this prudence is especially important in the current economic environment in North America. In 2010, the Company will significantly advance its capital program and continue to implement its strategy to grow the Pipelines and Energy businesses as discussed in the TCPL's Strategy section of this MD&A.

In 2010, the Pipelines segment is expected to begin generating EBITDA from the initial phase of Keystone. Keystone's EBITDA will increase as additional phases are completed and brought into service. Pipelines' EBITDA may be affected by the expiry of long-term contracts, variances in throughput volume particularly on the U.S. pipelines, customer settlements and decisions made by applicable regulatory authorities.

Energy's EBITDA in 2010 will be affected by commodity price changes in instances where TCPL has not entered into contracts that manage these fluctuations or in circumstances where existing sales contracts expire and are replaced with new contracts entered into at prevailing market prices. Energy's EBITDA will also be impacted by fluctuations in capacity prices in the New York City market where Ravenswood operates and in New England. Furthermore, Energy's EBITDA in 2010 will be positively impacted by assets that were placed in service during 2009 and assets that are expected to be placed in service in 2010.

TCPL also expects earnings in 2010 to be impacted by a reduction in capitalized interest and an increase in depreciation as new assets are placed into service.

On a consolidated basis, the impact of changes in the value of the U.S. dollar on U.S. Pipelines and Energy EBIT is largely offset by the impact of the changes in the value of the U.S. dollar on U.S. dollar interest expense. The resultant net exposure is managed using derivatives, effectively reducing the Company's exposure to changes in foreign exchange rates. The average U.S. dollar exchange rate for the year ended December 31, 2009 was 1.14 (2008 and 2007 1.07).

The Company's results in 2010 may be affected by a number of factors and developments as discussed throughout this MD&A including, without limitation, the factors and developments discussed in the Forward-Looking Information, Pipelines Business Risks and Energy Business Risks sections. Refer to the Pipelines Outlook and Energy Outlook sections of this MD&A for further discussion of outlook. Commencing January 1, 2011, the Company's results will be impacted by the adoption of International Financial Reporting Standards (IFRS) as discussed in the Accounting Changes Future Accounting Changes section in this MD&A.

The following pipelines are owned 100 per cent by TCPL unless otherwise stated.

CANADIAN MAINLINE The Canadian Mainline is a 14,101 km (8,762 miles) natural gas transmission system in Canada extending 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 The Alberta System is a 23,905 km (14,854 miles) natural gas transmission system in Alberta that connects with the Canadian Mainline and Foothills natural gas pipelines and with third-party natural gas pipelines.

ANR ANR is a 17,000 km (10,563 miles) transmission system that transports natural gas from producing fields located primarily in Texas, Oklahoma, the Gulf of Mexico and Louisiana to markets located mainly in Wisconsin, Michigan, Illinois, Ohio and Indiana. ANR also owns and operates regulated underground natural gas storage facilities in Michigan with a total working capacity of 250 Bcf.

GTN GTN is a 2,174 km (1,351 miles) transmission system linking Foothills and Rocky Mountain sourced natural gas with third-party natural gas pipelines in Washington, Oregon and California, and with Tuscarora.

FOOTHILLS Foothills is a 1,241 km (771 miles) transmission system in Western Canada carrying 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.

VENTURES LP Ventures LP is comprised of a 161 km (100 miles) pipeline supplying natural gas to the oilsands region near Fort McMurray, Alberta and a 27 km (17 miles) pipeline supplying natural gas to a petrochemical complex at Joffre, Alberta.

TAMAZUNCHALE Tamazunchale is a 130 km (81 miles) natural gas pipeline in east central Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi.

NORTH BAJA Owned 100 per cent by PipeLines LP, North Baja is a natural gas transmission system extending 129 km (80 miles) from Ehrenberg, Arizona to Ogilby, California and connecting with a third-party natural gas pipeline system in Mexico. TCPL operates North Baja and effectively owns 38.2 per cent of the system through its 38.2 per cent interest in PipeLines LP.

TUSCARORA Owned 100 per cent by PipeLines LP, Tuscarora is a 491 km (305 miles) pipeline system transporting natural gas from GTN at Malin, Oregon, to Wadsworth, Nevada, with delivery points in northeastern California and northwestern Nevada. TCPL operates Tuscarora and effectively owns 38.2 per cent (2008 32.1 per cent) of the system through its 38.2 per cent (2008 32.1 per cent) interest in PipeLines LP.

NORTHERN BORDER Owned 50 per cent by PipeLines LP, Northern Border is a 2,250 km (1,398 miles) natural gas transmission system serving the U.S. Midwest. TCPL operates Northern Border and effectively owns 19.1 per cent (2008 16.1 per cent) of the system through its 38.2 per cent (2008 32.1 per cent) interest in PipeLines LP.

GREAT LAKES Owned 53.6 per cent by TCPL and 46.4 per cent by PipeLines LP, Great Lakes is a 3,404 km (2,115 miles) natural gas transmission system serving markets in Central Canada and the midwestern U.S. TCPL operates Great Lakes and effectively owns 71.3 per cent (2008 68.5 per cent) of the system through its direct ownership interest and its 38.2 per cent (2008 32.1 per cent) interest in PipeLines LP.

IROQUOIS Owned 44.5 per cent by TCPL, Iroquois is a 666 km (414 miles) pipeline system that connects with the Canadian Mainline near Waddington, New York, and delivers natural gas to customers in the northeastern U.S.

TQM Owned 50 per cent by TCPL, TQM is a 572 km (355 miles) pipeline system that connects with the Canadian Mainline and transports natural gas from Montréal to Québec City in Québec, and connects with Portland. TQM is operated by TCPL.

PORTLAND Owned 61.7 per cent by TCPL, Portland is a 474 km (295 miles) pipeline that connects with TQM near East Hereford, Québec and delivers natural gas to customers in the northeastern U.S. Portland is operated by TCPL.

TRANSGAS Owned 46.5 per cent by TCPL, TransGas is a 344 km (214 miles) natural gas pipeline system extending from Mariquita to Cali in Colombia.

GAS PACIFICO/INNERGY Owned 30 per cent by TCPL, Gas Pacifico is a 540 km (336 miles) natural gas pipeline extending from Loma de la Lata, Argentina to Concepción, Chile. TCPL also has a 30 per cent ownership interest in INNERGY, an industrial natural gas marketing company based in Concepción that markets natural gas transported on Gas Pacifico.

BISON Once completed, the Bison natural gas pipeline will extend 487 km (303 miles) from the Powder River Basin in Wyoming to Northern Border in North Dakota.

KEYSTONE Owned 100 percent (December 31, 2008 62 per cent) by TCPL, Keystone is a 3,456 km (2,147 miles) oil pipeline that will initially transport crude oil from Hardisty, Alberta to U.S. Midwest markets at Wood River and Patoka, Illinois, and to Cushing, Oklahoma. In addition, a 2,720 km (1,690 miles) expansion to the Gulf Coast is under development.

GUADALAJARA The Guadalajara natural gas pipeline is under construction and when completed will extend approximately 305 km (190 miles) from Manzanillo to Guadalajara in Mexico.

PIPELINES HIGHLIGHTS

Comparable EBITDA from Pipelines was $3.1 billion in 2009, an increase of $0.1 billion from $3.0 billion in 2008.

The Company invested $3.9 billion in Pipelines capital projects in 2009, including completion of the first phase of construction of Keystone to Wood River and Patoka, Illinois, for approximately $2.5 billion. The Company also completed the first phase and commenced construction on the second phase of the Alberta System's North Central Corridor expansion at a total capital cost of approximately $600 million to the end of 2009. The expected total capital cost for the North Central Corridor project is approximately $800 million.

During 2009, TCPL negotiated a Rate Design Settlement for the Alberta System, which provided for a new rate design for the existing system and expansions. This settlement addresses the evolving nature of the Alberta System and the commercial integration of ATCO Pipelines.

In December 2009, a Joint Review Panel of the Canadian government released a report on environmental and socio-economic factors relating to the Mackenize Gas Pipeline (MGP) project. The report has been submitted to the National Energy Board of Canada (NEB) as part of the review process for approval of the project. A decision is expected by fourth quarter 2010.

In October 2009, the NEB issued a ruling that its adjustment formula for the rate of return on common equity (ROE) would no longer be in effect. The decision affects the calculation of future tolls for TCPL's NEB-regulated natural gas pipelines. Prior to this ruling, the NEB issued a decision awarding TQM a 6.4 per cent after-tax weighted average cost of capital (ATWACC) for 2007 and 2008.

In April 2009, TCPL received a decision from the NEB affirming that the Alberta System is within federal jurisdiction and is subject to regulation by the NEB.

In 2009, TCPL acquired ConocoPhillips' remaining interest in Keystone, increasing the Company's ownership to 100 per cent.

In 2009, as a result of PipeLines LP issuing common units to the public, the Company's interest was reduced to 38.2 per cent and a dilution gain of $29 million was realized.

In June 2009, TCPL entered into an agreement with ExxonMobil to jointly advance the Alaska pipeline.

PIPELINES RESULTS

Year ended December 31 *(millions of dollars)*

	2009	2008	2007
Canadian Pipelines			
Canadian Mainline	**1,133**	1,141	1,207
Alberta System	**728**	692	775
Foothills	**132**	133	135
Other (TQM, Ventures LP)	**59**	50	51
Canadian Pipelines Comparable EBITDA(1)	**2,052**	2,016	2,168
U.S. Pipelines			
ANR	**347**	347	272
GTN(2)	**195**	198	187
Great Lakes	**138**	127	125
PipeLines LP(2)(3)	**84**	70	62
Iroquois	**78**	59	55
Portland(4)	**26**	27	34
International (Tamazumchale, TransGas, Gas Pacifico/INNERGY)	**58**	40	51
General, administrative and support costs(5)	**(17)**	(15)	(17)
Non-controlling interests(2)(6)	**194**	187	187
U.S. Pipelines Comparable EBITDA(1)	**1,103**	1,040	956
Business Development Comparable EBITDA(1)	**(62)**	(37)	(47)
Pipelines Comparable EBITDA(1)	**3,093**	3,019	3,077
Depreciation and amortization	**(1,030)**	(989)	(1,021)
Pipelines Comparable EBIT (1)	**2,063**	2,030	2,056
Specific items:			
Dilution gain from reduced interest in PipeLines LP(3)(7)	**29**		
Calpine bankruptcy settlements(8)		279	
GTN lawsuit settlement		17	
Pipelines EBIT (1)	**2,092**	2,326	2,056

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of comparable EBITDA, comparable EBIT and EBIT.

(2) GTN's results include North Baja until July 1, 2009 when it was sold to PipeLines LP.

(3) Effective November 18, 2009, PipeLines LP's results reflected TCPL's effective ownership in PipeLines LP of 38.2 per cent. From July 1, 2009 to November 17, 2009, TCPL's ownership interest in PipeLines LP was 42.6 per cent. From February 22, 2007 to June 30, 2009, TCPL's ownership interest in PipeLines LP was 32.1 per cent. From January 1, 2007 to February 22, 2007, TCPL's ownership interest in PipeLines LP was 13.4 per cent.

(4) Portland's results reflect TCPL's 61.7 per cent ownership interest.

(5)

Represents certain costs associated with supporting the Company's Canadian and U.S. Pipelines.

(6) Non-controlling interests reflects EBITDA for the portions of PipeLines LP and Portland not owned by TCPL.

(7) As a result of PipeLines LP issuing common units to the public, the Company's ownership interest in PipeLines LP was reduced to 38.2 per cent from 42.6 per cent and a dilution gain of $29 million was realized.

(8) GTN and Portland received shares of Calpine with an initial value of $154 million and $103 million, respectively, as a result of the bankruptcy settlements with Calpine. These shares were subsequently sold for an additional gain of $22 million.

Pipelines generated comparable EBIT of $2,063 million in 2009 compared to $2,030 million in 2008. Comparable EBIT in 2009 excluded the $29 million pre-tax dilution gain resulting from TCPL's reduced interest in PipeLines LP, which occurred following the public issuance of common units by PipeLines LP in November 2009. Comparable EBIT in 2008 excluded the $279 million of gains received by Portland and GTN from the bankruptcy settlements with Calpine and the $17 million of proceeds received by GTN from a lawsuit settlement with a software supplier. Comparable EBIT in 2007 was $2,056 million.

Wholly Owned Canadian Pipelines Net Income

Year ended December 31 *(millions of dollars)*

	2009	2008	2007
Canadian Mainline	**273**	278	273
Alberta System	**168**	145	138
Foothills	**23**	24	26

PIPELINES FINANCIAL ANALYSIS

Canadian Mainline The Canadian Mainline is regulated by the NEB, which sets tolls that provide TCPL with the opportunity to recover projected costs of transporting natural gas, including a return on the Canadian Mainline's average investment base. The NEB also approves new facilities before construction begins. Canadian Mainline's EBITDA is affected by changes in investment base, the ROE, the level of deemed common equity, potential incentive earnings and changes in the level of depreciation, financial charges and income taxes recovered in revenue on a flow-through basis.

The Canadian Mainline currently operates under a five year tolls settlement effective from 2007 to 2011. The cost of capital reflects an ROE as determined by the NEB's ROE formula on deemed common equity of 40 per cent.

The tolls settlement also established certain elements of the Canadian Mainline's fixed operating, maintenance and administration (OM&A) costs for each of the five years. The variance between actual and agreed-upon OM&A costs accrued entirely to TCPL from 2007 to 2009, and will be shared equally between TCPL and its customers in 2010 and 2011. All other cost elements of the revenue requirement are treated on a flow-through basis. The settlement also allows for performance-based incentive arrangements that the Company believes are mutually beneficial to TCPL and its customers.

Net income of $273 million in 2009 was $5 million lower than $278 million in 2008. The decrease was primarily the result of a lower average investment base and a lower ROE of 8.57 per cent in 2009 compared to 8.71 per cent in 2008, partially offset by higher OM&A cost savings. Net income of $278 million in 2008 was $5 million higher than $273 million in 2007 primarily due to higher performance-based incentives, increased OM&A cost savings and an ROE of 8.71 per cent in 2008 compared to 8.46 per cent in 2007. These increases were partially offset by a lower average investment base.

Comparable EBITDA of $1,133 million in 2009 was $8 million lower than $1,141 million in 2008. The decrease was primarily due to lower revenues as a result of recovery of a lower overall return on a reduced average investment base and a lower ROE in 2009. The decrease in revenues was partially offset by higher OM&A cost savings and recovery of higher depreciation in 2009. EBITDA of $1,141 million in 2008 was $66 million lower than $1,207 million in 2007 primarily due to lower revenues as a result of the recovery of lower depreciation, financial charges and income taxes in 2008. The decrease in revenues was partially offset by higher EBITDA from performance-based incentives, OM&A cost savings and higher ROE.

Alberta System Effective April 29, 2009, the Alberta System became federally regulated by the NEB under the *National Energy Board Act* (Canada). The Alberta System was previously regulated by the Alberta Utilities Commission (AUC), primarily under the provisions of the *Gas Utilities Act* (Alberta) and *Pipeline Act* (Alberta). The Alberta System's EBITDA is affected by changes in investment base, the ROE, the level of deemed common equity, potential incentive earnings and changes in the level of depreciation, financial charges and income taxes recovered in revenue on a flow-through basis.

The Alberta System operates under the 2008 2009 Revenue Requirement Settlement originally approved by the AUC in December 2008 and subsequently approved by the NEB following the Alberta System's transfer to federal jurisdiction. In December 2009, the NEB approved TCPL's application to establish final 2009 tolls. In 2007, the Alberta System operated under the 2005 2007 Revenue Requirement Settlement approved by the AUC in June 2005.

As part of the 2008 2009 Revenue Requirement Settlement, fixed amounts were established for ROE, income taxes and certain OM&A costs. Any variances between actual costs and those agreed to in the settlement accrued to TCPL, subject to an ROE and income tax adjustment mechanism that accounted for variances between actual and settlement rate base, and income tax assumptions. The other cost elements of the settlement were treated on a flow-through basis.

The Alberta System's net income of $168 million in 2009 was $23 million higher than in 2008, primarily due to higher settlement earnings and a higher average investment base in 2009. Net income of $145 million in 2008 was $7 million higher than in 2007 due to increased earnings as a result of the 2008 2009 Revenue Requirement Settlement. Earnings in 2007 reflected an ROE of 8.51 per cent on deemed common equity of 35 per cent.

The Alberta System's comparable EBITDA of $728 million in 2009 was $36 million higher than in 2008, primarily due to higher settlement earnings and a higher average investment base in 2009 as well as increased revenues as a result of the recovery of higher financial charges, partially offset by lower income taxes. EBITDA of $692 million in 2008 was $83 million lower than in 2007. The decrease was due to lower revenues as a result of the recovery of lower depreciation, income taxes and financial charges, partially offset by increased earnings as a result of the 2008 2009 Revenue Requirement Settlement.

Other Canadian Pipelines Comparable EBITDA from Other Canadian Pipelines was $59 million in 2009 compared to $50 million in 2008. The increase was primarily due to the NEB decision reached in March 2009 on TQM's cost of capital for the years 2007 and 2008. EBITDA was $50 million in 2008 compared to $51 million in 2007.

ANR The operations of ANR are regulated primarily by the U.S. Federal Energy Regulatory Commission (FERC). ANR provides natural gas transportation, storage and various capacity-related services to a variety of North American customers. ANR's transmission system has a peak-day capacity of 6.8 billion cubic feet per day (Bcf/d). Due to the seasonal nature of its business, ANR's volumes and revenues are generally higher in the winter months. ANR also owns and operates 250 Bcf of regulated underground natural gas storage facilities in Michigan. ANR's natural gas storage and transportation services operate under current FERC-approved tariffs. These tariffs include maximum and minimum rates for services and permit ANR to discount or negotiate rates on a non-discriminatory basis.

ANR Pipeline Company (ANR Pipeline) rates were established pursuant to a settlement approved by the FERC effective November 1997. ANR Storage Company's rates were established pursuant to a settlement approved by the FERC effective June 1990. None of ANR's FERC-regulated operations are required to file for new rates at any time in the future, nor are any of the operations prohibited from filing a rate case.

ANR's comparable EBITDA in 2009 was $347 million, which was consistent with 2008. Higher transportation and storage revenues, as a result of expansion projects, increased utilization and favourable pricing on existing capacity, and the positive impact of a stronger U.S. dollar in 2009 were offset by lower incidental natural gas sales, primarily due to lower prices, and higher OM&A and business development costs. Comparable EBITDA in 2008 was $347 million compared to $272 million in 2007. The increase was primarily due to a full year of earnings in 2008 and increased revenue from new growth projects, partially offset by higher OM&A costs.

GTN GTN is regulated by the FERC and is operated in accordance with FERC-approved tariffs that establish maximum and minimum rates for various services. GTN's pipeline rates were established pursuant to a settlement approved by the FERC in January 2008, and these rates were effective January 1, 2007. Under the settlement, a five-year moratorium commencing January 1, 2007 was established during which GTN and the settling parties are prohibited from taking certain actions, including any filings to adjust rates. The settlement also requires GTN to file for new rates to be in effect no later than January 1, 2014. GTN is permitted to discount or negotiate these rates on a non-discriminatory basis. GTN's EBITDA is affected by variations in contracted volume levels, volumes delivered and prices charged under the various service types, as well as by variations in the costs of providing services.

GTN's comparable EBITDA was $195 million in 2009, a decrease of $3 million compared to 2008. The decrease was primarily due to the sale of North Baja to PipeLines LP in 2009, partially offset by the positive impact of a stronger U.S. dollar in 2009. GTN's EBITDA was $198 million in 2008, an increase of $11 million compared to 2007 primarily due to lower OM&A expenses.

Other U.S. Pipelines Comparable EBITDA from other U.S. Pipelines was $561 million in 2009 compared to $495 million in 2008. The increase was primarily due to the positive impact of a stronger U.S. dollar in 2009, the July 2009 PipeLines LP acquisition of North Baja, increased revenues from Gas Pacifico resulting from a new transportation agreement and higher short-term revenues from Iroquois. EBITDA was $497 million in 2007.

Business Development Pipelines' business development comparable EBITDA losses increased $25 million in 2009 compared to 2008 primarily due to higher business development costs related to the Alaska pipeline project.

Depreciation and Amortization Depreciation increased $41 million in 2009 compared to 2008 primarily due to a stronger U.S. dollar in 2009. The $32 million decrease in depreciation in 2008 compared to 2007 was primarily due to lower depreciation for the Alberta System.

PIPELINES OPPORTUNITIES AND DEVELOPMENTS

Crude Oil

Keystone In August 2009, TCPL purchased ConocoPhillips' remaining approximate 20 per cent interest in Keystone for US$553 million and the assumption of US$197 million of short-term debt. TCPL now owns 100 per cent of Keystone.

In 2008, TCPL entered into an agreement with ConocoPhillips to increase its equity ownership in Keystone to approximately 80 per cent from 50 per cent, with ConocoPhillips' equity ownership in Keystone being reduced concurrently to approximately 20 per cent from 50 per cent. In 2008 and prior to August 2009, TCPL funded 100 per cent of the construction expenditures until the participants' cumulative project capital contributions were aligned with their revised ownership interests. In 2009, prior to August, TCPL funded $1.3 billion of cash calls for Keystone, resulting in the Company acquiring an incremental increase in ownership of approximately 18 per cent for $313 million. In 2008, the Company funded $362 million of cash calls, resulting in an incremental increase in ownership of approximately 12 per cent for $176 million. TCPL's ownership interest was approximately 80 per cent and 62 per cent in August 2009 and at December 31, 2008, respectively.

After gaining regulatory approval in both Canada and the U.S., construction of Keystone began in May 2008. Commissioning of the first phase of Keystone, extending from Hardisty to Wood River and Patoka with an initial nominal capacity of 435,000 Bbl/d began in late 2009.

In June 2008, Keystone received approval from the NEB to add new pumping facilities to accommodate deliveries to the Cushing market. The second phase of Keystone is expected to expand nominal capacity to 591,000 Bbl/d and extend the pipeline to Cushing, with commissioning expected to commence in late 2010 and commercial in service expected to commence in first quarter 2011.

After an open season conducted during third quarter 2008, Keystone secured additional firm, long-term shipper contracts on its system. With these commitments, Keystone filed the necessary regulatory applications in Canada and the U.S. for approval to construct and operate the expansion of the pipeline system that is expected to provide additional capacity from Western Canada to the U.S. Gulf Coast in early 2013, increasing the total commercial capacity of Keystone to approximately 1.1 million Bbl/d. In September 2009, the NEB held a hearing to review the application for the new Canadian facilities required for the Keystone Gulf Coast expansion. The NEB is expected to issue a decision in first quarter 2010 on TCPL's application to construct and operate the facilities, including the proposed tolling methodology. Facility permits for the U.S. portion of the expansion are expected by fourth quarter 2010. Construction of the expansion facilities is anticipated to commence in first quarter 2011 following the receipt of the necessary regulatory approvals.

The capital cost of Keystone, including expansion to the Gulf Coast, if approved, is expected to be approximately US$12 billion with approximately US$5 billion spent to date. At December 31, 2009, costs of $470 million related to the Keystone expansion to the Gulf Coast are included in intangibles and other assets. Capital costs related to the construction of Keystone are subject to capital cost risk- and reward-sharing mechanisms with TCPL's customers.

The NEB issued approval to commence operations, including commissioning activities, for the Canadian portion of Keystone's facilities, subject to certain conditions. The approval for the Canadian segment of the pipeline was granted for a period ending approximately nine months from commencement of commercial in service, at a reduced maximum operating pressure (MOP), which will reduce throughput capacity below initial nominal capacity of 435,000 Bbl/d. Prior to the conclusion of this nine month period, Keystone is required to run additional in-line inspections on this segment. These inspections and any remedial work are expected to be completed within this nine month period. Following these activities, TCPL expects the MOP restriction to be lifted.

TCPL expects Keystone to commence delivery of crude oil from Hardisty, Alberta, to U.S. Midwest markets at Wood River and Patoka, Illinois beginning mid-2010, and to Cushing, Oklahoma in first quarter 2011. Pending regulatory approval, an expansion of the system to the U.S. Gulf Coast is expected to commence the delivery of crude oil in early 2013.

TCPL expects Keystone to begin generating EBITDA in 2010 with earnings increasing through 2011, 2012 and 2013 as expansion phases commence delivery of crude oil. Contracted volumes of 217,500 Bbl/d will increase to 910,000 Bbl/d from 2010 to 2013 as commercial in service of the Cushing and Gulf Coast phases commence. Based on current long-term commitments, Keystone is expected to generate EBITDA of approximately US$1.2 billion in 2013, its first full year of commercial operation servicing both the U.S. Midwest and Gulf Coast markets. If volumes were to increase to 1.1 million Bbl/d, the full commercial design of the system, Keystone would generate annual EBITDA of approximately US$1.5 billion. Keystone volumes could be economically expanded to 1.5 million Bbl/d from 1.1 million Bbl/d in response to additional market demand.

Natural Gas

NEB Changes

Changes to NEB ROE Formula In March 2009, the NEB initiated a process to consider the continuing applicability of its RH-2-94 Decision. This decision established an ROE adjustment formula tied to Government of Canada bond yields and had formed the basis for determining tolls for certain pipelines under NEB jurisdiction since 1995. In October 2009, the NEB determined that the RH-2-94 Decision would no longer be in effect. The NEB decided that the cost of capital would be determined by negotiations between pipeline companies and their shippers or by the NEB if a pipeline company files a cost of capital application. This decision affects certain NEB-regulated pipelines, including the Canadian Mainline, Alberta System, Foothills and TQM. TCPL will be working with customers and interested parties to determine the cost of capital to be used in calculating tolls beginning in 2010 for the Alberta System, Foothills and TQM, and for the Canadian Mainline upon expiry of its existing settlement. If agreements cannot be reached, applications will be filed with the NEB requesting an appropriate return on capital.

In November 2009, the Canadian Association of Petroleum Producers and the Industrial Gas Users Association sought leave to appeal the October 2009 NEB decision to the Federal Court of Appeal and named the NEB as the sole respondent. In January 2010, TCPL was granted respondent status in the matter and in February 2010 filed its submission opposing the leave application.

Asset Retirement Obligations In May 2009, the NEB issued a decision on the Land Matters Consultation Initiative with respect to financial issues related to pipeline abandonment. All pipeline companies regulated under the *National Energy Board Act* (Canada) will be required to comply with the framework and action plan set out in the decision. The NEB's goal is to have pipeline companies begin collecting and setting aside funds to cover future abandonment costs no later than mid-2014. There are several filing deadlines in the action plan with which NEB regulated pipeline companies have to comply, including deadlines for preparing and filing an estimate of the abandonment costs, developing a proposal for collection of funds through tolls or some other satisfactory method and developing a proposed process to set aside the funds collected. As a result of this decision, TCPL has initiated a project to estimate the abandonment costs on its NEB-regulated pipelines. The estimate will be filed with the NEB for approval by May 31, 2011.

Canadian Mainline The Canadian Mainline will continue to base its return on the NEB's ROE formula for 2010 and 2011 in accordance with the terms of the current Canadian Mainline tolls settlement. In December 2009, the NEB approved TCPL's application for 2010 final tolls for the Canadian Mainline's transportation service, effective January 1, 2010. The 2010 calculated ROE for the Canadian Mainline will be 8.52 per cent, a decrease from 8.57 per cent in 2009.

Alberta System Effective April 29, 2009, the Alberta System became regulated by the NEB under the *National Energy Board Act* (Canada). The Alberta System was previously regulated by the AUC. Under federal regulation, TCPL is able to apply to the NEB for approval to extend the Alberta System across provincial borders, allowing the Company to provide service to producers outside of Alberta.

In September 2009, TCPL began construction on the final phase of the North Central Corridor natural gas pipeline, a 300 km (186 miles) extension of the Alberta System's northern section. This final phase is expected to be completed by April 2010. The initial phase was completed and operational in 2009. The North Central Corridor pipeline will provide capacity to accommodate increasing natural gas supply in northwest Alberta and northeast B.C. and growing markets in Alberta, and to offset declining natural gas supply in northeast Alberta while delivering more natural gas to the Alberta/Saskatchewan border. The total capital cost of the project is estimated to be approximately $800 million.

TCPL expects producers will continue to explore and develop new gas fields in Western Canada, particularly in northeastern B.C. and the west and central foothills regions of Alberta. There is also expected to be significant exploration and development activity aimed at unconventional resources such as coalbed methane and shale gas. The emergence of economically producible unconventional gas from B.C. shale gas supply, including the Montney and Horn River regions, has the potential to become a significant new opportunity for the Alberta System. While these areas are in their early stages of development, they appear to be comparable to U.S. shale gas supply volumes. Current estimates of the potential gas supply from these two areas range from 70 trillion cubic feet to 150 trillion cubic feet.

In November 2009, the NEB concluded a public hearing on TCPL's application for approval to construct and operate the Groundbirch pipeline, which is comprised of a 77 km (48 miles) natural gas pipeline and related above-ground facilities. TCPL has entered into firm transportation agreements with Groundbirch customers that are expected to increase to 1.1 Bcf/d by 2014. The Groundbirch pipeline, if approved, will be an extension of the Alberta System and will connect natural gas supply primarily from the Montney shale gas formation in northeast B.C. to existing infrastructure in northwest Alberta. Construction of the Groundbirch pipeline is expected to commence in July 2010 with completion anticipated in November 2010. A decision from the NEB is expected in first quarter 2010. The total capital cost of the project is estimated to be $200 million.

In May 2009, TCPL filed a Project Description with the NEB to initiate a regulatory review of the proposed Horn River project, which comprises construction of a 72 km (45 miles) natural gas pipeline and related facilities, including above-ground facilities, and acquisition of the existing 83 km (52 miles) Ekwan pipeline from EnCana Corporation. The Horn River project would connect new shale natural gas supply in the Horn River basin north of Fort Nelson, B.C. to the Alberta System. Total contractual commitments for Horn River have increased to 503 million cubic feet per day (mmcf/d) by 2014 from 378 mmcf/d as a result of newly contracted volumes from a recently announced natural gas processing facility that will be located in the Horn River area. As part of the Horn River project, in November 2009, TCPL entered into an agreement to acquire the Ekwan pipeline, which is expected to close in September 2011. In February 2010, the Company filed an application with the NEB for approval to construct and operate the Horn River project. Subject to regulatory approvals, the Horn River project is anticipated to commence operations in second quarter 2012. The total capital cost of the project is expected to be approximately $310 million.

Both the Groundbirch and Horn River projects are proposed as extensions to the Alberta System, which would provide B.C. producers with direct integrated gas transmission service from receipt points in B.C. These pipeline projects would also increase netbacks to producers and throughput on the Alberta System and increase usage of the Nova Inventory Transfer commercial hub that is used by buyers and sellers of natural gas throughout North America.

NOVA Gas Transmission Ltd. (NGTL) and Canadian Utilities Limited (ATCO Pipelines) continue to work towards obtaining the necessary regulatory approvals to provide commercial and operational integrated services to shippers on the Alberta System and the ATCO Pipelines system in Alberta. Final decisions from the AUC and NEB are expected by mid-2010 with implementation occurring within 12 months following receipt of required regulatory approvals. The integration of commercial and operational services on the Alberta System and ATCO Pipelines system will create the effect of a single integrated natural gas transmission system in Alberta, resulting in more efficient transportation of natural gas for customers.

During 2009, TCPL negotiated an Alberta System Rate Design Settlement with all key stakeholders. This rate design addresses the evolving nature of the Alberta System and the commercial and operational integration of ATCO Pipelines. It also incorporates a single delivery service for all delivery points resulting from the amalgamation of the current intra-Alberta and export delivery services. The changes are expected to improve the Alberta System's services by making them more consistent and adding flexibility for customers. The Company filed a combination application with the NEB on November 27, 2009 for approval of both the Rate Design Settlement and the integration of commercial and operational services on the Alberta System and ATCO Pipelines' system in Alberta. A final decision is expected from the NEB by mid-2010 with implementation occurring within the 12 months following approval.

TQM In March 2009, TQM received the NEB's decision on its cost of capital application for 2007 and 2008, which requested an 11 per cent return on 40 per cent deemed common equity. The NEB set a 6.4 per cent ATWACC for each of the two years, which equates to a 9.85 per cent return on 40 per cent deemed common equity in 2007 and a 9.75 per cent return on 40 per cent deemed common equity in 2008. Prior to the decision, TQM was subject to the NEB ROE formula of 8.46 per cent and 8.71 per cent for 2007 and 2008, respectively, on deemed common equity of 30 per cent. In June 2009, the NEB approved TQM's final tolls for 2007 and 2008, which reflected the 6.4 per cent ATWACC.

Ventures LP In May 2009, the AUC concluded an investigation of the rates on Ventures LP and determined they are unjust and unreasonable. The AUC sought an Order in Council from the Alberta government to proceed with a process to establish new rates. In September 2009, the Alberta Court of Appeal granted Ventures LP leave to appeal the AUC's decision. The appeal is expected to be heard in March 2010.

ANR In 2009, ANR received regulatory approval of the Wisconsin 2009 Project to construct a pipeline with capacity of approximately 97 mmcf/d that will deliver incremental natural gas to Wisconsin markets. A portion of the pipeline was placed in service in 2009. The remainder of the project is expected to be completed in 2010.

In 2009, four new interstate pipelines made supply interconnections with ANR's southeast leg, comprising a combined interconnect capacity of 1.5 Bcf/d. The interconnections increased ANR's access to natural gas supply from the mid-continent shale and Rocky Mountain regions, and from a Gulf Coast LNG regassification terminal.

In September 2008, certain portions of ANR's Gulf of Mexico offshore facilities were damaged by Hurricane Ike. The Company estimates its total exposure to damage costs to be approximately US$30 million to US$40 million, mainly to replace, repair and abandon capital assets, including the estimated cost to abandon an offshore platform. At December 31, 2009, related capital expenditures of US$11 million (2008 US$2 million) and OM&A costs of US$7 million (2008 US$6 million) had been incurred. The remaining costs are expected to be incurred in 2010 and 2011, with the majority to be incurred in 2011. Service on the offshore facilities has been restored and related throughput volumes have returned to pre-hurricane levels.

Portland In April 2008, Portland filed a general rate case with the FERC proposing a rate increase of approximately six per cent as well as other changes to its tariff. In May 2009, Portland reached a settlement with its customers on certain short-term issues in its rate case. The partial settlement was filed with the FERC for approval and a decision is expected in 2010. The remaining issues were litigated and Portland received the Initial Decision from the Administrative Law Judge in December 2009. Participants in the rate case have an opportunity to respond to the Initial Decision. The FERC is expected to issue its final decision on the litigated portion of the rate case in fourth quarter 2010.

PipeLines LP/North Baja On July 1, 2009, TCPL sold North Baja to PipeLines LP. As part of the transaction, TCPL agreed to amend its incentive distribution rights with PipeLines LP. Under the amendment, TCPL received additional common units in exchange for a resetting of its incentive distribution rights at a lower percentage which escalates with increases in PipeLines LP's distributions. TCPL received aggregate consideration totalling approximately US$395 million from PipeLines LP, including US$200 million in cash and 6,371,680 common units of PipeLines LP. TCPL's ownership in PipeLines LP increased to 42.6 per cent as a result of this transaction and TCPL continues to operate North Baja. TCPL's ownership in PipeLines LP was reduced to 38.2 per cent in November 2009 after PipeLines LP's public issuance of common units.

Great Lakes In November 2009, the FERC initiated an investigation to determine whether Great Lakes' rates are just and reasonable. In response, Great Lakes filed a cost and revenue study with the FERC on February 4, 2010. A hearing is scheduled to commence on August 2, 2010, and an Initial Decision is required in November 2010. The impact of the investigation on Great Lakes' rates and revenues is unknown at this time.

Palomar In December 2008, Palomar Gas Transmission LLC applied to the FERC for a certificate to build a 349 km (217 miles) natural gas pipeline extending from GTN in central Oregon, to the Columbia River northwest of Portland. The proposed pipeline has a capacity of up to 1.3 Bcf/d of natural gas. The project is a 50/50 joint venture between GTN and Northwest Natural Gas Co. Palomar is currently in discussions with potential shippers to secure shipping commitments for the project.

Guadalajara In May 2009, TCPL entered into a contract to build, own and operate a US$320 million pipeline in Mexico, which is supported by a 25 year contract for its entire capacity with the Comisión Federal de Electricidad, Mexico's state-owned electric power company. The Guadalajara pipeline project is a proposed natural gas pipeline of approximately 305 km (190 miles) extending from Manzanillo to Guadalajara. Regulatory approvals were received in December 2009 and construction is underway with an expected in-service date of first quarter 2011.

U.S. Rockies Pipeline Projects The Bison project is a 487 km (303 miles) proposed natural gas pipeline from the Powder River Basin in Wyoming connecting to Northern Border in North Dakota. The FERC issued a Final Environmental Impact Statement in December 2009 and the project is in the final stages of the regulatory approval process. The Company expects to commence construction in May 2010. The pipeline has shipping commitments for approximately 407 mmcf/d and is expected to be placed in service in fourth quarter 2010. The capital cost of the Bison pipeline project is estimated to be US$600 million.

Previously, TCPL was working to develop the Pathfinder and Sunstone pipeline projects, which were proposed to deliver natural gas from the Rocky Mountains to various U.S. markets. Based on market conditions, TCPL has elected to consolidate its Rocky Mountain development plans and will pursue additional development opportunities using the Bison pipeline as a platform for medium-term growth.

Alaska Pipeline Project In November 2007, TCPL submitted an application to the State of Alaska for a license to construct the Alaska pipeline project under the *Alaska Gasline Inducement Act* (AGIA). In January 2008, the State of Alaska determined that TCPL's application was the only proposal that met all of the state's requirements and the AGIA license was issued to TCPL in December 2008. Under the AGIA, the state of Alaska has agreed to reimburse a share of TCPL's eligible pre-construction costs, as they are incurred, and approved by the state to a maximum of US$500 million.

In June 2009, TCPL entered into an agreement with ExxonMobil to jointly advance the project. A joint project team is developing the engineering, environmental, aboriginal relations and commercial work.

The proposed Alaska pipeline project is a 4.5 Bcf/d natural gas pipeline extending 2,737 km (1,700 miles) from a new natural gas treatment plant at Prudhoe Bay, Alaska to Alberta. This pipeline will provide access to diverse markets across North America and is expected to have an estimated capital cost of US$32 billion to US$41 billion. The pipeline construction application included provisions to expand capacity up to 5.9 Bcf/d through the addition of compressor stations in Alaska and Canada. The current estimated capital cost for the project is an increase over previously stated estimates. The latest estimate is based on increased costs for oil and gas projects from 2007 to 2009 and a significant increase in the estimated cost of building the gas treatment plant at Prudhoe Bay. TCPL also proposed an alternate pipeline from Prudhoe Bay to Valdez, Alaska to supply LNG markets with an estimated capital cost of US$20 billion to US$26 billion.

On January 29, 2010, the Alaska pipeline project filed to obtain FERC approval to conduct an open season. If approval is granted, an open season offering is expected to be provided to potential shippers at the end of April 2010 for their assessment until July 2010. Both project options will be offered to shippers as alternative projects and both options have an expected in-service date of 2020. TCPL is continuing to work with potential shippers for the initial open season.

Mackenzie Gas Pipeline Project The MGP is a proposed 1,200 km (746 miles) natural gas pipeline extending from a point near Inuvik, Northwest Territories to the northern border of Alberta, where it will connect to the Alberta System.

TCPL's involvement with the MGP arises from a 2003 agreement between the Mackenzie Valley Aboriginal Pipeline Group (APG) and the MGP, whereby TCPL agreed to finance the APG's one-third share of the pre-development costs associated with the project. These costs, on a cumulative basis, are currently forecast to be between $150 million and $200 million. Under the terms of certain MGP agreements, TCPL holds an option to acquire up to a five per cent equity ownership in the MGP at the time of the decision to construct it. In addition, TCPL gains certain rights of first refusal to acquire 50 per cent of any divestitures by 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 other natural gas pipeline owners and the APG sharing the balance.

Cumulative advances to the APG by TCPL totalled $143 million at December 31, 2009 (2008 $140 million) and are included in intangibles and other assets. These advances constitute a loan to the APG, which becomes repayable only after the natural gas pipeline commences commercial operations. The total amount of the loan is expected to form part of the rate base of the pipeline and to be repaid from the APG's share of future natural gas pipeline revenues or from alternate financing. If the project does not proceed, TCPL has no recourse against the APG for recovery of advances made.

TCPL and the other co-venture companies involved in the MGP continue to pursue approval of the proposed project, focusing on obtaining regulatory approval and the Canadian government's support of an acceptable fiscal framework. The regulatory process reached a milestone in late December 2009 with the release of the Joint Review Panel's report on environmental and socio-economic factors relating to the project. The report has been submitted to the NEB as part of the review process required for approval of the project. The NEB review is scheduled to conclude with final arguments in April 2010. A decision by the NEB is currently expected by fourth quarter 2010. Project timing continues to be uncertain. In the event the co-venture group is unable to reach an agreement with the government on an acceptable fiscal framework, the parties will need to determine the appropriate next steps for the project. For TCPL, this may result in a reassessment of the carrying amount of the APG advances.

PIPELINES BUSINESS RISKS

Natural Gas Supply, Markets and Competition TCPL faces competition at both the supply and market ends of its natural gas pipelines systems. This competition comes from other natural gas pipelines accessing the increasingly mature WCSB and markets served by TCPL's pipelines as well as from natural gas supplies produced in basins not directly served by the Company. Growth in supply and pipeline infrastructure has increased competition throughout North America. Production in the U.S. has increased, driven primarily by shale gas, while WCSB production has declined. The lower cost shale gas in the U.S. has resulted in an increase in competition between supply basins, changes to traditional flow patterns and an increase in choices for customers. This change has contributed to a continued reduction in long-term firm contracted capacity and a shift to short-term firm and interruptible contracts.

Although TCPL has diversified its natural gas supply sources through recent pipeline acquisitions, many of its North American natural gas pipelines and its transmission infrastructure remain dependent on supply from the WCSB. The WCSB has established natural gas reserves of approximately 61 trillion cubic feet and a reserves-to-production ratio of approximately 11 years at current levels of production. Supply from the WCSB has declined in recent years due to a continued reduction in drilling activity in the basin. The reduced drilling activity is a result of lower prices, higher supply costs, which include increased royalties in Alberta, and competition for capital from other North American gas production basins that have lower exploration costs. Drilling levels in the WCSB are expected to recover in the future, assuming natural gas prices stabilize and finding and development costs become more economical. TCPL expects there will be excess natural gas pipeline capacity from the WCSB for the foreseeable future as a result of capacity expansions on its natural gas pipelines over the past decade, competition from other pipelines, and significant growth in natural gas consumption within Alberta driven by oilsands and electricity generation requirements.

TCPL's Alberta System is the major natural gas gathering and transportation system for the WCSB, connecting most of the natural gas processing plants in Alberta to domestic and export markets. Despite reduced overall drilling levels, activity remains robust in certain areas of the WCSB, which has resulted in the need for new transmission infrastructure. Drilling activity has increased in northwestern Alberta, near Grande Prairie, and in northeastern B.C., near Dawson Creek, as producers develop projects to access multi-zone reserves with deeper wells and to access unconventional shale gas utilizing horizontally drilled wells. Recently, shale gas production in B.C. has emerged as a potentially significant natural gas supply source. TCPL currently forecasts 3.5 Bcf/d total production from the Montney and Horn River shale gas sources by 2020. TCPL is currently pursuing two major extensions of its Alberta System that would allow emergent unconventional B.C. gas production from the Montney and Horn River shale gas plays to be transported to markets served by TCPL's pipeline systems.

Demand for natural gas in Eastern Canada and the U.S. Northeast decreased in 2009 largely as a result of a reduction in industrial demand caused by the global recession. However, future demand for natural gas in TCPL's key eastern markets, which are served by the Canadian Mainline, is expected to increase over time, particularly to meet the expected growth in natural gas-fired power generation. Although there are opportunities to increase market share in Canadian domestic and U.S. export markets, TCPL faces significant competition in these markets. Consumers in the northeastern U.S. generally have access to an array of natural gas pipeline and supply options. Eastern markets that historically received Canadian supplies only from TCPL's systems are now able to receive supplies from new natural gas pipelines that source U.S. and Atlantic Canada supplies. In recent years, the Canadian Mainline has experienced reductions in volumes originating at the Alberta border and in Saskatchewan, which have been partially offset by increases in volumes originating at points east of Saskatchewan. These net volume reductions have resulted in an increase in Canadian Mainline tolls that adversely affects its competitive position.

ANR's directly connected natural gas supply is primarily sourced from the Gulf of Mexico and mid-continent U.S. regions, which are also served by competing natural gas pipelines. The Gulf of Mexico region is highly competitive given its extensive natural gas pipeline network. ANR is one of many interstate and intrastate pipelines competing for new and existing production as well as for new supplies from pipelines originating in the mid-continent shale and Rocky Mountain production regions, and from new and existing Gulf Coast LNG regassification terminals. ANR has competition from other natural gas pipelines and storage operations in its primary markets in the U.S. Midwest. In addition to pipeline competition for market and supply, difficult economic conditions have reduced natural gas demand and may put future ANR capacity renewals at risk. As lower natural gas prices reduce drilling activity, the supply growth that has been fuelling the expansion of pipeline infrastructure in the mid-continent could slow down but is still expected to exceed demand requirements in the near term. These factors could negatively affect the value of pipeline capacity as transportation capacity becomes more abundant.

ANR's natural gas storage is primarily contracted on a short-term basis of three to five years. Storage is recontracted based on current market conditions, which may become unfavourable and result in reduced rates and terms.

GTN must compete with other pipelines to access natural gas supplies and markets. Transportation service capacity on GTN provides customers in the U.S. Pacific Northwest, California and Nevada with access to supplies of natural gas primarily from the WCSB. These three markets may also access supplies from other basins. In the Pacific Northwest market, natural gas transported on GTN competes with the Rocky Mountain natural gas supply and with additional Western Canadian supply transported by other pipelines. Historically, natural gas supplies from the WCSB have been competitively priced in relation to supplies from the other regions serving these markets. Recently, low natural gas prices have reduced drilling and production in the WCSB resulting in increased competition for supply which could negatively impact transportation value on GTN. Pacific Gas and Electric Company, GTN's largest customer, has received California Public Utilities Commission approval to commit to capacity on a proposed competing project out of the Rocky Mountain basin to the California border.

Crude Oil Supply, Markets and Competition Alberta is the primary source of crude oil supply for Keystone, producing approximately 79 per cent of the oil in the WCSB. In 2009, the WCSB produced an estimated 2.5 million Bbl/d, comprised of 1.1 million Bbl/d of conventional crude oil and condensate, and 1.4 million Bbl/d of crude oil from Alberta's oilsands. The production of conventional crude oil has been declining but has been offset by increases in production from the Alberta oilsands. The Alberta Energy Resources Conservation Board estimated in its June 2009 report that there are approximately 170 billion barrels of remaining established reserves in the Alberta oilsands.

In June 2009, the Canadian Association of Petroleum Producers forecasted WCSB crude oil supply would increase to 3.3 million Bbl/d by 2015 and to 3.9 million Bbl/d by 2020 from 2.4 million Bbl/d in 2008. In first quarter 2010, crude oil producers announced plans to undertake approximately $8 billion of new oilsands projects, indicating future growth in Alberta oilsands production.

Keystone currently has contracted a significant portion of its capacity. Keystone will compete for spot market throughput with other crude oil pipelines from Alberta and for new long-term contracts as supply from the WCSB increases.

Keystone's markets for crude oil are refiners in the U.S. Midwest and Gulf Coast regions. Keystone will compete with pipelines that deliver WCSB crude oil to these markets through interconnections with other pipelines. Keystone will also compete with U.S. domestically produced crude oil and imported crude oil for markets in the U.S. Midwest and Gulf Coast regions.

Regulatory Financial Risk Regulatory decisions continue to have a significant impact on the financial returns from existing investments in TCPL's Canadian pipelines and are expected to have a similarly significant impact on financial returns from future investments. Through rate applications and negotiated settlements, TCPL has been able to improve the financial returns of its Canadian pipeline capital structures.

Regulations and decisions by regulatory bodies, particularly those issued in the U.S. by the FERC, Environmental Protection Agency and Department of Transportation, may have a significant impact on the financial returns from TCPL's existing investments in U.S. pipelines. TCPL continually monitors existing and proposed regulations to determine the possible impact on its U.S. pipelines.

Throughput Risk As transportation contracts expire, TCPL's U.S. natural gas pipelines are expected to become more exposed to the risk of reduced throughput and their revenues are more likely to experience increased variability. Throughput risk is created by supply and market competition, economic activity, weather variability, natural gas pipeline competition and pricing of alternative fuels.

Execution and Capital Cost Risk Capital costs related to the construction of Keystone are subject to a capital cost risk- and reward-sharing mechanism with TCPL's customers. This mechanism allows Keystone to adjust its tolls by a factor based on the percentage change in the capital cost of the project. Tolls for the portion of Keystone to Wood River, Patoka and Cushing will be adjusted by a factor equal to 50 per cent of the percentage change in capital cost. Tolls on the expansion to the Gulf Coast would be adjusted by a factor equal to 75 per cent of the percentage change in capital cost.

Refer to the Risk Management and Financial Instruments section of this MD&A for information on additional risks and managing risks in the Pipelines business.

PIPELINES OUTLOOK

Although demand for natural gas and crude oil has declined and is expected to remain relatively weak in North America in 2010 due to the current economic conditions, the Company expects demand to increase in the long term. TCPL's Pipelines business will continue to focus on the delivery of natural gas and crude oil to growing markets, connecting new supply and progressing development of new infrastructure to connect natural gas from the north and unconventional supplies such as shale gas, coalbed methane and LNG.

Reduced throughput and greater use of shorter distance transportation contracts are the primary factors contributing to an increase in the Canadian Mainline's toll of approximately 40 per cent in 2010 from 2009. This situation, coupled with the ongoing development and growth of competitive alternative natural gas supply and infrastructure from U.S. shale gas regions, is increasing competitive pressures on the Canadian Mainline. In response, TCPL has initiated a process to examine the Canadian Mainline's rate design, business model and available services to develop solutions that would result in higher throughput and revenue as well as lower costs and tolls. TCPL is also pursuing the connection of new sources of U.S. gas supply to the existing Canadian Mainline infrastructure to maintain its current markets and competitive position.

Most of TCPL's expansion plans in Canadian natural gas transmission are focused on the Alberta System. TCPL is actively involved in expanding the Alberta System to serve the growing shale gas regions in northeastern B.C. Additional growth opportunities for the Alberta System include the west and central foothills regions of Alberta.

In the U.S., TCPL expects unconventional production will continue to be developed from shale gas reservoirs in east Texas, northwest Louisiana, Arkansas, southwest Oklahoma and the Appalachian Mountain region. Supplies from coalbed methane and tight gas sands in the Rocky Mountain region are also expected to grow. Additionally, in the medium to long term, some level of incremental supply is anticipated from LNG imports into the U.S., particularly in the summer months. The resulting growth in U.S. supply is expected to provide additional opportunities for TCPL. In particular, the southwest leg of ANR is expected to continue to remain fully subscribed for the foreseeable future and new transport routes are being developed to move additional Rocky Mountain and shale gas production to mid-western and eastern U.S. markets, including interconnections with ANR. The southeast leg of ANR is well positioned and has capacity to transport additional volumes of unconventional and Rocky Mountain natural gas production as well as LNG.

Producers continue to develop new crude oil supply in Western Canada. Several Alberta oilsands projects recently completed or under construction will begin to produce oil or will increase crude oil production in 2010 and 2011. Oilsands production is forecast to increase to 2.2 million Bbl/d by 2015 from 1.2 million Bbl/d in 2008 and total Western Canada crude oil supply is projected to grow over the same period to 3.3 million Bbl/d from 2.4 million Bbl/d. Most of this growth is in heavy crude oil supply. The primary market for new crude oil production extends from the U.S. Midwest to the Gulf Coast and contains a large number of refineries that are well equipped to handle Canadian light and heavy crude oil blends. Incremental western Canadian crude oil production is expected to replace declining U.S. imports of crude oil from other countries.

The increase in WCSB crude oil exports from Alberta requires access to new markets, including the Gulf Coast. TCPL will continue to pursue additional opportunities to move crude oil from Alberta to U.S. markets.

TCPL will continue to focus on operational excellence and collaboration with all stakeholders to achieve negotiated settlements and provision of services that will increase the value of the Company's business.

Earnings The Company expects continued growth on its Alberta System. TCPL also anticipates a modest level of investment in its other Canadian natural gas pipelines but expects a continued net decline in the average investment bases of these pipelines due to annual depreciation. A net decline in the average investment base has the effect of reducing year-over-year earnings from these assets. Under the current regulatory model, earnings from Canadian 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 addition, Pipelines' EBITDA is expected to be affected by costs to develop new pipeline projects, including the Alaska pipeline project.

Reduced firm transportation contract volumes due to customer defaults, lower supply available for export from the WCSB and expiry of long-term contracts could have a negative impact on short-term earnings from TCPL's U.S. natural gas pipelines, unless the available capacity can be recontracted. The ability to recontract available capacity is influenced by prevailing market conditions and competitive factors, including competing natural gas pipelines and supply from other natural gas sources in markets served by TCPL's U.S. pipelines. EBITDA from Pipelines' foreign operations is also impacted by changes in foreign currency exchange rates.

EBITDA from Keystone is expected to commence in 2010 and continue to increase over the short term until all phases of Keystone are fully operational in 2013. Refer to the Pipelines Opportunities and Developments section of this MD&A for further information on Keystone's expected EBITDA.

Capital Expenditures Total capital spending for all pipelines in 2009 was $3.9 billion. Capital spending for the wholly owned pipelines in 2010, including Keystone, is expected to be approximately $4.7 billion.

NATURAL GAS THROUGHPUT VOLUMES

(Bcf)

	2009	2008	2007
Canadian Mainline[(1)]	**2,030**	2,173	2,315
Alberta System[(2)]	**3,538**	3,800	4,020
ANR[(3)]	**1,575**	1,619	1,189
Foothills	**1,205**	1,292	1,441
GTN	**797**	783	827
Great Lakes	**727**	784	829
Northern Border	**614**	731	800
Iroquois	**355**	376	394
TQM	**164**	170	207
Ventures LP	**145**	165	178
North Baja	**96**	104	90
Gas Pacifico	**62**	73	71
Tamazunchale	**54**	53	29
Portland	**37**	50	58
Tuscarora	**35**	30	28
TransGas	**28**	26	24

(1) Canadian Mainline's throughput volumes in the above table reflect physical deliveries to domestic and export markets. Throughput volumes reported in previous years reflected contract deliveries. However, customer contracting patterns have changed in recent years making physical deliveries a better measure of system utilization. Canadian Mainline physical receipts originating at the Alberta border and in Saskatchewan in 2009 were 1,579 Bcf (2008 1,898 Bcf; 2007 2,090 Bcf).

(2) Field receipt volumes for the Alberta System in 2009 were 3,550 Bcf (2008 3,843 Bcf; 2007 4,047 Bcf).

(3) ANR's results include delivery volumes from its acquisition date of February 22, 2007.

The following Energy assets are owned 100 per cent by TCPL unless otherwise stated.

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 TCPL has the rights to 100 per cent of the generating capacity of the 560 MW Sundance A coal-fired power generating facility under a PPA that expires in 2017. TCPL also has the rights to 50 per cent of the generating capacity of the 706 MW Sundance B facility under a PPA that expires in 2020. The Sundance facilities are located in south-central Alberta.

SHEERNESS TCPL has the rights to 756 MW of generating capacity from the Sheerness coal-fired plant under a PPA that expires in 2020. The Sheerness plant is located in southeastern Alberta.

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

CANCARB A 27 MW facility located in Medicine Hat, Alberta fuelled by waste heat from TCPL's adjacent facility producing thermal carbon black (a natural gas by-product).

BRUCE POWER Bruce Power is a nuclear generating facility located northwest of Toronto, Ontario. TCPL owns 48.8 per cent of Bruce A, which has four 750 MW reactors. Two of these reactors are currently operating with the remaining two being refurbished. TCPL owns 31.6 per cent of Bruce B, which has four operating reactors with a combined capacity of approximately 3,200 MW.

HALTON HILLS A 683 MW natural gas-fired power plant under construction near Halton Hills, Ontario.

PORTLANDS ENERGY A 550 MW natural gas-fired, combined-cycle power plant located in Toronto, Ontario. The plant is 50 per cent owned by TCPL.

OAKVILLE A proposed 900 MW natural gas-fired, combined-cycle power plant under development in Oakville, Ontario.

BÉCANCOUR A 550 MW natural gas-fired cogeneration power plant located near Trois-Rivières, Québec.

CARTIER WIND The 590 MW Cartier Wind farm consists of five wind power projects located in Québec and is 62 per cent owned by TCPL. Three of the wind farms, Baie-des-Sables, Anse-à-Valleau and Carleton, are in service and have a total generating capacity of 320 MW. Construction activity has begun on the two remaining wind farms, which have a total generating capacity of 270 MW.

GRANDVIEW A 90 MW natural gas-fired cogeneration power plant located in Saint John, New Brunswick.

KIBBY WIND A 132 MW wind power project located in Kibby and Skinner Townships in Maine. The first phase of the project is operating and has a generating capacity of 66 MW. Phase two is under construction and will have a generating capacity of 66 MW.

TC HYDRO TC Hydro has a total generating capacity of 583 MW and is comprised of 13 hydroelectric facilities, including stations and associated dams and reservoirs, on the Connecticut and Deerfield rivers in New Hampshire, Vermont and Massachusetts.

OSP A 560 MW natural gas-fired, combined-cycle facility located in Burrillville, Rhode Island.

RAVENSWOOD A 2,480 MW multiple unit generating facility located in Queens, New York, employing dual-fuel capable steam turbine, combined-cycle and combustion turbine technology.

COOLIDGE A 575 MW simple-cycle, natural gas-fired peaking power facility under construction in Coolidge, Arizona.

EDSON An underground natural gas storage facility connected to the Alberta System near Edson, Alberta. Edson's central processing system is capable of maximum injection and withdrawal rates of 725 mmcf/d of natural gas, and has a working storage capacity of approximately 50 Bcf.

CROSSALTA A 68 Bcf underground natural gas storage facility connected to the Alberta System near Crossfield, Alberta. CrossAlta's central processing system is capable of maximum injection and withdrawal rates of 550 mmcf/d of natural gas. TCPL owns 60 per cent of CrossAlta.

ENERGY HIGHLIGHTS

Energy's comparable EBITDA was $1.1 billion in 2009, a decrease of $0.1 billion from $1.2 billion in 2008.

In 2009, the Company invested $1.5 billion in Energy capital projects, including:

The 550 MW Portlands Energy facility, which was fully commissioned in April 2009 and completed under budget; and

the first phase of the Kibby Wind power project, which was placed in service in October 2009, six weeks ahead of schedule, and was also completed under budget.

In July 2009, Bruce Power and the OPA amended certain terms and conditions included in the Bruce Power Refurbishment Implementation Agreement. The amendments are consistent with the intent of the contract, originally signed in 2005, and recognize the significant changes in Ontario's electricity market.

The Bruce A Unit 1 and 2 refurbishment and restart project continues. Unit 2 is expected to return to service in mid-2011 with Unit 1 to follow approximately four months later. TCPL expects its share of the capital costs to complete this project to be approximately $2 billion.

Approximately 3,100 MW of generation capacity was under construction and in development at December 31, 2009, at an anticipated capital cost of approximately $7 billion.

POWER PLANTS NOMINAL GENERATING CAPACITY AND FUEL TYPE

	MW	Fuel Type
Canadian Power		
Western Power		
Sheerness	756	Coal
Coolidge(1)	575	Natural gas
Sundance A	560	Coal
Sundance B(2)	353	Coal
MacKay River	165	Natural gas
Carseland	80	Natural gas
Bear Creek	80	Natural gas
Redwater	40	Natural gas
Cancarb	27	Natural gas
	2,636	
Eastern Power		
Oakville(1)	900	Natural gas
Halton Hills(1)	683	Natural gas
Bécancour	550	Natural gas
Cartier Wind(1)(3)	365	Wind
Portlands Energy(4)	275	Natural gas
Grandview	90	Natural gas
	2,863	
Bruce(5)	2,480	Nuclear

	7,979	
U.S. Power		
Ravenswood	2,480	Natural gas/oil
TC Hydro	583	Hydro
OSP	560	Natural gas
Kibby Wind[1]	132	Wind
	3,755	
Total nominal generating capacity[1]	11,734	

(1) Coolidge, Halton Hills, two Cartier Wind farms (168 MW) and phase two of Kibby Wind (66 MW) are currently under construction. Oakville is currently under development.

(2) Represents TCPL's 50 per cent share of the Sundance B power plant output.

(3) Represents TCPL's 62 per cent share of this total 590 MW project.

(4) Represents TCPL's 50 per cent share of this 550 MW facility.

(5) Represents TCPL's 48.8 per cent proportionate interest in Bruce A and 31.6 per cent proportionate interest in Bruce B.

ENERGY RESULTS

Year ended December 31 *(millions of dollars)*

	2009	2008	2007
Canadian Power			
Western Power	**279**	510	385
Eastern Power	**220**	147	120
Bruce Power	**352**	275	240
General, administrative and support costs	**(39)**	(39)	(35)
Canadian Power Comparable EBITDA(1)	**812**	893	710
U.S. Power			
Northeast Power	**237**	272	184
General, administrative and support costs	**(45)**	(41)	(32)
U.S. Power Comparable EBITDA(1)	**192**	231	152
Natural Gas Storage			
Alberta Storage	**173**	152	151
General, administrative and support costs	**(9)**	(14)	(14)
Natural Gas Storage Comparable EBITDA(1)	**164**	138	137
Business Development Comparable EBITDA(1)	**(37)**	(52)	(55)
Energy Comparable EBITDA(1)	**1,131**	1,210	944
Depreciation and amortization	**(347)**	(258)	(216)
Energy Comparable EBIT (1)	**784**	952	728
Specific items:			
Fair value adjustments of natural gas inventory in storage and forward contracts	**1**		10
Writedown of Broadwater LNG project costs		(41)	
Gain on sale of land			16
Energy EBIT(1)	**785**	911	754

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of comparable EBITDA, comparable EBIT and EBIT.

Energy's comparable EBIT was $784 million in 2009 compared to $952 million in 2008. Comparable EBIT excluded net unrealized gains of $1 million and nil in 2009 and 2008, respectively, resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Comparable EBIT in 2008 excluded the $41 million writedown of costs previously capitalized for the Broadwater LNG project.

Energy's comparable EBIT in 2008 of $952 million increased $224 million compared to $728 million in 2007. Comparable EBIT in 2007 excluded a $16 million gain on sale of land and $10 million of net unrealized gains resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

ENERGY FINANCIAL ANALYSIS

Western Power As at December 31, 2009, Western Power owned or had the rights to approximately 2,600 MW of power supply in Alberta and the Western U.S. from its three long-term PPAs, five natural gas-fired cogeneration facilities and a simple-cycle, natural gas peaking facility under construction in Arizona. The current operating power supply portfolio of Western Power in Alberta comprises approximately 1,700 MW of low-cost, base-load coal-fired generation supply through the three long-term PPAs and approximately 400 MW of natural gas-fired cogeneration assets. This supply portfolio includes some of the lowest cost, most competitive generation in the Alberta market area. The Sheerness and Sundance B PPAs expire in 2020, while the Sundance A PPA expires in 2017. Plant operations in Alberta consist of five natural gas-fired cogeneration power plants ranging from 27 MW to 165 MW per facility. A portion of the expected output from these facilities is sold under long-term contracts and the remaining output is subject to fluctuations in the price of power and natural gas.

Western Power relies on its two integrated functions, marketing and plant operations, to generate earnings. The marketing function, based in Calgary, Alberta, purchases and resells electricity sourced through the PPAs, markets uncommitted 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 critical for optimizing Energy's return from its portfolio of power supply and managing risks associated with uncontracted volumes. A portion of Energy's power is sold into the spot market to ensure supply in case of unexpected plant outages. The overall amount of spot market volumes is dependent upon the ability to transact in forward sales markets at acceptable contract terms. This approach to portfolio management helps to minimize costs in situations where TCPL would otherwise have to purchase electricity in the open market to fulfil its contractual sales obligations. To reduce exposure to spot market prices on uncontracted volumes, as at December 31, 2009, Western Power had fixed-price power sales contracts to sell approximately 8,400 gigawatt hours (GWh) in 2010 and 6,000 GWh in 2011.

Eastern Power Eastern Power owns approximately 2,900 MW of power generation capacity, including facilities under construction or in the development phase. Eastern Power's current operating power generation assets are Bécancour, three Cartier Wind farms, Portlands Energy and Grandview.

Bécancour's entire power output is supplied to Hydro-Québec under a 20 year power purchase contract expiring in 2026. Steam from this facility is sold to an industrial customer for use in commercial processes. Electricity generation at the Bécancour power plant has been temporarily suspended since January 2008 due to an agreement entered into with Hydro-Québec. Under the agreement TCPL continues to receive payments similar to those that would have been received under the normal course of operation. The suspension of the Bécancour power facility is discussed further in the Energy Opportunities and Developments section of this MD&A.

Cartier Wind's three wind farms, Carleton, Anse-à-Valleau, and Baie-des-Sables, were placed into service in November 2008, November 2007 and November 2006, respectively. Output from these wind farms is supplied to Hydro-Québec under 20 year power purchase contracts.

Portlands Energy was placed into service in April 2009. This facility provides power under a 20 year Accelerated Clean Energy Supply contract with the OPA.

Grandview is located on the site of the Irving oil refinery in Saint John, New Brunswick. Irving is under a 20 year tolling arrangement, which expires in 2025, to supply fuel for the plant and to contract 100 per cent of the 90 MW plant's heat and electricity output.

Eastern Power is focused on selling power under long-term contracts. In 2007, 2008 and 2009, all of Eastern Power sales volumes were sold under contract and are expected to continue to be 100 per cent sold under contract for 2010 and 2011.

Western and Eastern Canadian Power Comparable EBITDA[1][2]
Year ended December 31 *(millions of dollars)*

	2009	2008	2007
Revenues			
Western power	**788**	1,140	1,045
Eastern power	**281**	175	400
Other[3]	**184**	186	89
	1,253	1,501	1,534
Commodity purchases resold			
Western power	**(451)**	(517)	(550)
Eastern power			(2)
Other[4]	**(124)**	(112)	(65)
	(575)	(629)	(617)
Plant operating costs and other	**(179)**	(215)	(412)
General, administrative and support costs	**(39)**	(39)	(35)
Comparable EBITDA[1]	**460**	618	470

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of comparable EBITDA.

(2) Includes Portlands Energy, Carleton and Anse-à-Valleau effective April 2009, November 2008 and November 2007, respectively.

(3) Other revenue includes sales of natural gas, sulphur sales in 2008 and thermal carbon black.

(4) Other commodity purchases resold includes the cost of natural gas sold.

Western and Eastern Canadian Power Operating Statistics[1]
Year ended December 31

	2009	2008	2007
Sales Volumes (GWh)			
Supply			
Generation			
Western Power	**2,334**	2,322	2,154
Eastern Power	**1,550**	1,069	5,200
Purchased			
Sundance A & B and Sheerness PPAs	**10,603**	12,368	12,199
Other purchases	**529**	970	1,710
	15,016	16,729	21,263
Sales			
Contracted			
Western Power	**9,944**	11,284	11,998
Eastern Power	**1,588**	1,232	5,477
Spot			
Western Power	**3,484**	4,213	3,788
	15,016	16,729	21,263
Plant Availability[2]			
Western Power[3]	**93%**	87%	90%
Eastern Power	**97%**	97%	97%

(1) Includes Portlands Energy, Carleton and Anse-à-Valleau effective April 2009, November 2008, November 2007, respectively. Bécancour is included only in 2007 due to the agreement with Hydro-Québec to temporarily suspend electricity generation in 2008 and 2009.

(2) Plant availability represents the percentage of time in a year that the plant is available to generate power regardless of whether it is running.

(3) Excludes facilities that provide power to TCPL under PPAs.

Western Power's comparable EBITDA of $279 million in 2009 decreased $231 million compared to $510 million in 2008. The decrease was primarily due to a decline in earnings from the Alberta power portfolio resulting from lower overall realized prices on reduced volumes of power sold. In addition, Western Power's EBITDA in 2008 included $23 million related to sulphur sales.

Lower overall realized power prices and lower sales volumes resulted in a decrease of $352 million in Western Power's power revenues in 2009 compared to 2008. Average spot market power prices in Alberta decreased 47 per cent, or $42 per megawatt hour (MWh) in 2009 compared to 2008 and Western Power's sales volumes decreased 13 per cent in 2009 from 2008 primarily as a result of reduced dispatch of the Alberta PPAs. The reduction in power prices and sales volumes both reflected reduced demand for electricity in Alberta as a result of the North American economic downturn. Commodity purchases resold of $451 million in 2009 decreased $66 million compared to 2008 due to a reduction in volumes purchased and the expiry of certain retail contracts. Approximately 26 per cent of Western Power's sales volumes were sold in the spot market in 2009 compared to 27 per cent in 2008.

Eastern Power's comparable EBITDA of $220 million in 2009 increased $73 million compared to $147 million in 2008. The increase was primarily due to incremental earnings from Portlands Energy, which was placed in service in April 2009, and the Carleton wind farm at Cartier Wind, which went into service in November 2008, as well as higher contracted revenue from the Bécancour facility. Eastern Power's power revenues increased $106 million primarily due to the incremental revenues from Portlands Energy and the Carleton wind farm.

Other revenues and other commodity purchases resold were $184 million and $124 million, respectively, in 2009 compared to $186 million and $112 million, respectively, in 2008. These changes reflected an increase in the quantity of natural gas being resold in Eastern Power. Increased sales of natural gas in other revenues in 2009 were more than offset by the sale of sulphur in 2008.

Plant operating costs and other, which includes fuel gas consumed in power generation, of $179 million in 2009 decreased $36 million from 2008 primarily due to lower prices for natural gas in Western Power, partially offset by incremental fuel consumed at Portlands Energy.

Western Power's comparable EBITDA was $510 million in 2008, an increase of $125 million from $385 million in 2007. The increase was primarily due to increased margins from a combination of higher overall realized power prices on uncontracted volumes of power sold and a $23 million increase from sales of sulphur at significantly higher prices in 2008. In 2008, the Company sold the remainder of its sulphur stock pile, which it had been selling in modest quantities on a break-even basis since 2005.

Western Power's power revenues increased $95 million in 2008 compared to 2007 primarily due to the higher overall power sales prices. Commodity purchases resold decreased $33 million in 2008 compared to 2007 primarily due to a decrease in volumes purchased and the expiry of certain retail contracts. Purchased power volumes in 2008 decreased from 2007 primarily due to the expiry of certain retail contracts, partially offset by increased utilization from the Alberta PPAs. Approximately 27 per cent of power sales volumes were sold in the spot market in 2008 compared to 24 per cent in 2007.

Eastern Power's comparable EBITDA of $147 million in 2008 increased $27 million compared to 2007 as a result of higher contracted earnings from the Bécancour facility, incremental earnings from the first full year of operations from the Anse-à-Valleau wind farm and the start up of the Carleton wind farm in 2008.

The agreement to temporarily suspend generation at the Bécancour facility beginning January 2008 resulted in decreases to Eastern Power's power revenues, generation volumes and contracted sales as well as plant operating costs and other in 2008 compared to 2007.

Decreases in plant operating costs and other in 2008 compared to 2007 due to the temporary suspension of the Bécancour facility were partially offset by higher volumes of gas purchased at higher prices in Western Power.

Western Power's plants operated with an average availability of approximately 93 per cent in 2009 compared to 87 per cent in 2008, primarily due to the return to service of the Cancarb facility in April 2009. Western Power's overall plant availability was negatively affected from late 2007 until April 2009 by an outage at the Cancarb power plant. Eastern Power achieved plant availability of 97 per cent in 2009, consistent with 2008 and 2007. Bécancour, which had an availability of 97 per cent in 2007, is not included in Eastern Power's 2009 and 2008 measurement as power generation from the plant was suspended throughout 2008 and 2009.

Bruce Power Bruce Power is a nuclear power generation facility located northwest of Toronto, Ontario and is comprised of Bruce A and Bruce B. Bruce A has four 750 MW reactors, of which two are currently operating and two are being refurbished. One unit is expected to be restarted in mid-2011 and the other unit is expected to be restarted approximately four months thereafter. Bruce B has four operating reactors with a combined capacity of 3,200 MW. As at December 31, 2009, TCPL and BPC Generation Infrastructure Trust (BPC), a trust established by the Ontario Municipal Employees Retirement System (OMERS), each owned a 48.8 per cent interest in Bruce A (2008 48.9 per cent; 2007 48.7 per cent). The remaining 2.4 per cent interest in Bruce A is owned by the Power Workers' Union Trust (PWU), the Society of Energy Professionals Trust (SEP) and Bruce Power Employee Investment Trust. The Bruce A partnership subleases Bruce A Units 1 to 4 from the Bruce B partnership. TCPL, OMERS and Cameco Corporation each own 31.6 per cent of Bruce B, which consists of Units 5 to 8 and the supporting site infrastructure. The remaining interest in Bruce B is owned by PWU and SEP.

The following Bruce Power financial results reflect TCPL's proportionate share of the eight Bruce Power units, six of which were operating:

Bruce Power Results
(TCPL's proportionate share)
Year ended December 31 *(millions of dollars unless otherwise indicated)*

	2009	2008	2007
Revenues[1][2]	**883**	785	847
Operating expenses[2]	**(531)**	(510)	(607)
Comparable EBITDA[3]	**352**	275	240
Bruce A Comparable EBITDA[3]	**48**	78	38
Bruce B Comparable EBITDA[3]	**304**	197	202
Comparable EBITDA[3]	**352**	275	240

Bruce Power Other Information			
Plant availability			
Bruce A	**78%**	82%	78%
Bruce B	**91%**	87%	89%
Combined Bruce Power	**87%**	86%	86%
Planned outage days			
Bruce A	**56**	91	121
Bruce B	**45**	100	93
Unplanned outage days			
Bruce A	**82**	27	17
Bruce B	**47**	65	32
Sales volumes (GWh)			
Bruce A	**4,894**	5,159	4,959
Bruce B	**7,767**	7,799	7,992
	12,661	12,958	12,951
Results per MWh			
Bruce A power revenues	**$64**	$62	$59
Bruce B power revenues[4]	**$64**	$57	$52
Combined Bruce Power revenues	**$64**	$59	$55
Percentage of output sold to spot market[5]	**43%**	33%	62%

(1) Revenues include Bruce A fuel cost recoveries of $34 million in 2009 (2008 $30 million; 2007 $17 million). Revenues also include Bruce B unrealized gains of $5 million as a result of changes in the fair value of held-for-trading derivatives in 2009 (2008 $2 million losses; 2007 $15 million gains).

(2) Includes adjustments to eliminate the effects of inter-partnership transactions between Bruce A and Bruce B.

(3) Refer to the Non-GAAP Measures section in this MD&A for further discussion of comparable EBITDA.

(4) Includes revenues received under the floor price mechanism, from contract settlements and from deemed generation, and the associated volumes.

(5) All of Bruce B's output is covered by the floor price mechanism, including volumes sold to the spot market.

TCPL's proportionate share of Bruce Power's comparable EBITDA increased $77 million to $352 million in 2009 compared to 2008 primarily due to higher realized prices and reduced annual lease expense, partially offset by lower volumes and higher operating expenses for Bruce A.

TCPL's proportionate share of Bruce A's comparable EBITDA decreased $30 million to $48 million in 2009 compared to 2008 as a result of lower volumes and higher operating expenses due to an increase in outage days, partially offset by higher contracted prices for output.

TCPL's proportionate share of Bruce B's comparable EBITDA increased $107 million to $304 million in 2009 compared to 2008 primarily due to higher realized prices resulting from the recognition of payments received pursuant to the floor price mechanism in Bruce B's contract with the OPA and a reduction in annual lease expense. Provisions in a lease agreement with Ontario Power Generation allowed for a reduction in annual lease expense as the annual average

Ontario spot price for electricity was less than $30 per MWh. The annual average Ontario spot price was $29.52 per MWh in 2009 compared to 48.83 per MWh in 2008.

Amounts received under the floor price mechanism in any calendar year are subject to repayment if the annual average spot price exceeds the annual average floor price. In 2009, the annual average spot price did not exceed the annual average floor price, therefore, no amounts recorded in revenue in 2009 will be repaid. Bruce B did not recognize into revenue any of the support payments received under the floor price mechanism in 2007 or 2008 as the annual average spot price exceeded the annual average floor price.

TCPL's proportionate share of Bruce Power's comparable EBITDA in 2008 increased $35 million to $275 million compared to 2007 as a result of higher realized prices and increased volumes associated with a decrease in outage days at Bruce A in 2008.

TCPL's proportionate share of Bruce Power's generation in 2009 decreased to 12,661 GWh compared to 12,958 GWh in 2008, partially due to periods in 2009 when the Independent Electricity System Operator (IESO) curtailed certain units at Bruce Power to address surplus base load generation in Ontario. During these unit curtailments by the IESO, Bruce Power received deemed generation payments at OPA contract prices. Including deemed generation, the combined average availability of Bruce A and Bruce B was 87 per cent in 2009 compared to 86 per cent in 2008. TCPL's proportionate share of Bruce Power's generation in 2008 was consistent with 2007.

The overall plant availability percentage in 2010 is expected to be in the mid-80s for the two operating Bruce A units and in the high 80s for the four Bruce B units. An approximate ten week maintenance outage of Bruce A Unit 3 is scheduled to begin in late February 2010. Maintenance outages of approximately eight weeks are scheduled to begin in May 2010 for Bruce B Unit 6 and mid-October 2010 for Bruce B Unit 5.

Bruce A

Under a contract with the OPA, all of the output from Bruce A is effectively sold at a fixed price per MWh, adjusted for inflation annually each April 1. In addition, fuel costs are recovered from the OPA. In accordance with a 2007 contract amendment, effective April 1, 2009, the fixed price for output from Bruce A was $64.45 per MWh.

Bruce A Fixed Price

		per MWh
April 1, 2009	March 31, 2010	$64.45
April 1, 2008	March 31, 2009	$63.00
April 1, 2007	March 31, 2008	$59.69

Bruce B

As part of Bruce Power's contract with the OPA, all output from Bruce B Units 5 to 8 are subject to a floor price adjusted annually for inflation on April 1.

Bruce B Floor Price

		per MWh
April 1, 2009	March 31, 2010	$48.76
April 1, 2008	March 31, 2009	$47.66
April 1, 2007	March 31, 2008	$46.82

Payments received pursuant to the Bruce B floor price mechanism were previously subject to a recapture payment dependent on annual spot prices over the entire term of the contract. In July 2009, the contract with the OPA was amended making payments received pursuant to the floor price mechanism subject to recapture payments dependent on annual spot prices only within each calendar year.

Bruce B enters into fixed-price contracts under which it receives the difference between the contract price and spot price. As a result, Bruce B's 2009 realized price of $64 per MWh reflects revenues recognized from both the floor price mechanism and contract sales, compared to $57 per MWh and $52 per MWh in 2008 and 2007, respectively. As at December 31, 2009, Bruce B had entered into fixed-price contracts to sell forward approximately 2,100 GWh for 2010 and 500 GWh for 2011, representing TCPL's proportionate share.

U.S. Power U.S. Power owns approximately 3,800 MW of power generation capacity, including facilities under construction. U.S. Power's current operating power generation assets are Ravenswood, TC Hydro, OSP, and phase one of Kibby Wind. Ravenswood, located in Queens, New York and acquired in August 2008, is a 2,480 MW natural gas and oil-fired generating facility consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology with the capacity to serve approximately 21 per cent of the overall peak load in New York City. The TC Hydro assets include 13 hydroelectric stations housing a total of 39 hydroelectric generating units in New Hampshire, Vermont and Massachusetts with total generating capacity of 583 MW. OSP, a 560 MW natural gas-fired combined-cycle facility, is the largest power plant in Rhode Island and phase one of Kibby Wind is a 66 MW wind farm located in Maine.

U.S. Power conducts its business primarily in the deregulated New England and New York power markets through its wholly owned subsidiary, TCPM, located in Westborough, Massachusetts. TCPM focuses 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. Power is purchased to satisfy a significant portion of TCPM's retail and wholesale power sales commitments, mitigating its exposure to fluctuations in spot market prices and effectively locking in a positive margin. Power generation is managed by entering into contracts to sell a portion of power forecasted to be generated. Corresponding contracts are entered into simultaneously to purchase the fuel required to reduce exposure to market price volatility and lock in positive margins. In 2009, TCPM continued to expand its marketing presence and customer base in the New England and New York markets.

The New England Power Pool relies on a Forward Capacity Market (FCM) to promote investment in new and existing power resources needed to meet growing consumer demand and maintain a reliable power system. FCM payments began in late 2006 and operated on a transition basis from 2007 to 2009. During this period, OSP and TC Hydro received capacity transition payments under this mechanism as specified in the FERC-approved FCM settlement. Beginning in June 2010, the price paid for capacity will be determined by annual competitive FCM auctions, which are held three years in advance of the capacity year in question. Future auction results will be affected by actual versus projected demand, the pace of progress in developing new qualifying resources that bid into the auctions and other factors.

The New York Independent System Operator (NYISO) relies on a locational capacity market intended to promote investment in new and existing power resources needed to meet growing consumer demand and maintain a reliable power system. At present, a series of voluntary forward auctions and a mandatory spot demand curve price setting process are used to determine the price paid to capacity suppliers. There are two annual six-month strip forward auctions and 12 monthly forward auctions in which buyer and seller participation is optional. All remaining available capacity is required to participate in a monthly spot auction in the final week prior to the capacity month. The spot auction clears at a price based on a downward sloping demand curve, the parameters of which are determined by the NYISO and approved by the FERC. There are separate demand curves for each of three defined capacity zones: Long Island, New York City, and Rest of State. The Ravenswood capacity is located in the New York City capacity zone.

U.S. Power Comparable EBITDA[1][2]
Year ended December 31 *(millions of dollars)*

	2009	2008	2007
Revenues			
Power	**1,118**	938	1,035
Capacity	**190**	85	46
Other[3],[4]	**509**	350	239
	1,817	1,373	1,320
Commodity purchases resold			
Power	**(544)**	(519)	(753)
Other[5]	**(391)**	(324)	(208)
	(935)	(843)	(961)
Plant operating costs and other[4]	**(645)**	(258)	(175)
General, administrative and support costs	**(45)**	(41)	(32)
Comparable EBITDA[1]	**192**	231	152

(1) Refer to the Non-GAAP Measures section of this MD&A for further discussion of comparable EBITDA.

(2) Includes phase one of Kibby Wind and Ravenswood as of October 2009 and August 2008, respectively.

(3) Includes sales of natural gas.

(4) Includes Ravenswood revenues and costs related to a third-party service agreement.

(5) Other commodity purchases resold includes the cost of natural gas sold.

U.S. Power Operating Statistics[1]
Year ended December 31

	2009	2008	2007
Sales Volumes (GWh)			
Supply			
Generation	**5,993**	3,974	2,895
Purchased	**5,310**	6,020	6,709
	11,303	9,994	9,604
Sales			
Contracted	**10,264**	9,758	9,028
Spot	**1,039**	236	576
	11,303	9,994	9,604

Plant Availability[2]	**79%**	75%	95%

(1) Includes phase one of Kibby Wind and Ravenswood as of October 2009 and August 2008, respectively.

(2) Plant availability represents the percentage of time in a year that the plant is available to generate power regardless of whether it is running.

U.S. Power's comparable EBITDA was $192 million in 2009, $39 million lower than the $231 million earned in 2008. The decrease was primarily due to reduced power prices and lower margins realized on generation volumes in New England, partially offset by forward hedging activities. Lower realized prices were a result of the economic downturn coupled with unseasonably mild weather. These decreases were partially offset by incremental revenue realized on contract sales at higher than average spot market prices in New England. The reduction in New England EBITDA was partially offset by incremental EBITDA from a full year of operations at the Ravenswood facility, which was acquired in August 2008, and the positive impact of a stronger U.S. dollar in 2009. Ravenswood results in 2009 were impacted by spot prices, which were 52 per cent lower than in 2008, and reduced power demand.

U.S. Power's power revenues of $1,118 million in 2009, increased $180 million from $938 million in 2008 primarily due to incremental revenues from the Ravenswood facility, the positive impact of a stronger U.S. dollar and an increase in financial contract sales, partially offset by lower volumes of power sold at lower prices in New England. Capacity revenue of $190 million in 2009 increased $105 million from $85 million in 2008 primarily due to incremental capacity revenue from Ravenswood, which is earned based on plant availability regardless of whether the plant is generating electricity.

Other revenues increased $159 million in 2009 compared to 2008 as a result of higher volumes of natural gas sold, revenues earned from the third-party service agreement at Ravenswood and the positive impact of a stronger U.S. dollar.

Power commodity purchases resold increased $25 million in 2009 compared to 2008 primarily due to the incremental impact of financial contract purchases in New England and the impact of a stronger U.S. dollar in 2009. These increases were partially offset by lower volumes of power purchased for resale at lower prices to commercial and industrial customers in New England.

Other commodity purchases resold increased $67 million in 2009 compared to 2008 primarily due to higher volumes of unutilized natural gas purchased for plant fuel and resold as well as the impact of a stronger U.S. dollar, partially offset by a decrease in natural gas prices.

Plant operating costs and other increased $387 million in 2009 compared to 2008 due to a full year of operations and costs related to a third-party service agreement at Ravenswood, as well as the impact of a stronger U.S. dollar.

Comparable EBITDA was $231 million in 2008, $79 million higher than the $152 million earned in 2007. The increase was primarily due to increased water flows from the TC Hydro generation assets and higher realized prices on sales to commercial and industrial customers in New England. On December 31, 2008, Ravenswood fulfilled its obligations under a tolling agreement with a third party that was in place at the time of its acquisition. Beginning in 2009, TCPM has managed the marketing output of the Ravenswood plant in a manner consistent with its other U.S. Northeast portfolio of assets.

U.S. Power achieved plant availability of 79 per cent in 2009 compared to 75 per cent in 2008 primarily due to the return to service of Ravenswood Unit 30 in May 2009 following an unplanned outage. Plant availability in 2008 was 20 per cent lower than in 2007 as a result of outages experienced at Ravenswood throughout fourth quarter 2008.

In 2009, nine per cent of power sales volumes were sold into the spot market compared to two per cent in 2008. At December 31, 2009, U.S. Power had fixed price sales contracts to sell forward approximately 10,300 GWh in 2010 and 5,400 GWh in 2011, including financial contracts to economically hedge the price of forecasted power generation. Certain contracted volumes are dependent on customer usage levels. Actual amounts contracted in future periods will depend on market liquidity and other factors. Power has been purchased to satisfy a portion of these sales requirements, reducing exposure to volatility in spot prices and effectively locking in a margin.

Natural Gas Storage TCPL owns or has rights to 129 Bcf of non-regulated natural gas storage capacity in Alberta, including a 60 per cent ownership interest in CrossAlta, an independently operated storage facility. TCPL also has contracts for long-term, Alberta-based storage capacity from a third party, which expire in 2030, subject to early termination rights in 2015.

Natural Gas Storage Capacity

	Working Gas Storage Capacity (Bcf)	Maximum Injection/ Withdrawal Capacity (mmcf/d)
Edson	50	725
CrossAlta[(1)]	41	550
Third-party storage	38	630
	129	1,905

(1) Represents TCPL's 60 per cent ownership interest in CrossAlta. Working gas storage capacity can vary due to the amount of base gas in the facility.

The Company's natural gas storage capability helps balance seasonal and short-term supply and demand, and adds flexibility to the delivery of natural gas to markets in Alberta and the rest of North America. The increasing seasonal imbalance in North American natural gas supply and demand has increased natural gas price volatility and the demand for storage services. Alberta-based storage will continue to serve market needs and could play an important role as additional gas supplies are connected to North American markets. Energy's natural gas storage business operates independently from TCPL's regulated natural gas transmission business and from ANR's regulated storage business, which is included in TCPL's Pipelines segment.

TCPL manages the exposure of its non-regulated natural gas storage assets to seasonal natural gas price spreads by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales.

Market volatility creates arbitrage opportunities and TCPL's storage facilities provide customers with the ability to capture value from short-term price movements. At December 31, 2009, TCPL had contracted approximately 75 per cent of the total 129 Bcf of working gas storage capacity in 2010 and 51 per cent of storage capacity in 2011. Earnings from third-party storage capacity contracts are recognized over the terms of the contracts.

Proprietary natural gas storage transactions are comprised of a forward purchase of natural gas to be injected into storage and a simultaneous forward sale of natural gas for withdrawal at a later period, typically during the winter withdrawal season. By matching purchase and sales volumes on a back-to-back basis, TCPL locks in future positive margins, effectively eliminating its exposure to natural gas seasonal price spreads.

These forward natural gas contracts provide highly effective economic hedges but do not meet the specific criteria for hedge accounting and, therefore, are recorded at their fair value based on the forward market prices for the contracted month of delivery. Changes in the fair value of these contracts are recorded in revenues. TCPL records its proprietary natural gas inventory in storage at its fair value using a weighted average of forward prices for natural gas for the following four months, less selling costs. Changes in the fair value of inventory are recorded in revenues. Changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sales contracts are excluded in determining comparable earnings, as they are not representative of amounts that will be realized on settlement.

Natural Gas Storage's comparable EBITDA in 2009 was $164 million compared to $138 million in 2008. The $26 million increase in EBITDA was primarily due to increased third-party storage revenues as a result of higher realized seasonal natural gas price spreads. Natural Gas Storage's comparable EBITDA was $138 million in 2008 which was consistent with 2007.

Business Development Business development comparable EBITDA losses in 2009 decreased $15 million compared to 2008 primarily due to the timing of expenses on certain key projects.

Depreciation and Amortization Depreciation and amortization of $347 million in 2009 increased $89 million compared to 2008 primarily due to a full year of operations at Ravenswood, capital additions at Bruce Power and the start-up of Portlands Energy and the Carleton wind farm in April 2009 and November 2008, respectively.

ENERGY OPPORTUNITIES AND DEVELOPMENTS

Ravenswood From the time of its acquisition to December 31, 2008, Ravenswood operated under a tolling arrangement under which all energy generated from the facility was provided to a third party for a fixed operating fee. In January 2009, Ravenswood commenced earning revenues from the sale of energy generated from the facility into the New York market. TCPM manages the marketing of output from Ravenswood.

Subsequent to closing the acquisition of Ravenswood, TCPL experienced a forced outage event related to Ravenswood's 972 MW Unit 30. The unit returned to service in May 2009. The Company continues to work with its insurers with respect to claims for both the physical damage and business interruption losses associated with the outage. No amounts have been accrued for claims with respect to business interruption losses.

Bruce Power Under a long-term agreement reached in 2005 between Bruce Power and the OPA, Bruce A committed to refurbish and restart the currently idle Units 1 and 2, extend the operating life of Unit 3 and replace the steam generators on Unit 4. An amendment to the agreement in 2007 provided for a full refurbishment of Unit 4, which will extend the expected operating life of the unit.

In 2008, Bruce Power completed a review of the operating life estimates for Units 3 and 4. As a result of that review, Unit 3 was expected to remain in commercial service until 2011, providing an additional two years of power generation before refurbishment. After the refurbishment, the operating life of Unit 3 was to be extended to 2038. The review also showed that Unit 4 was expected to remain in commercial service until 2016, providing seven years of generation before refurbishment, after which the estimated operating life of Unit 4 was expected to be extended to 2042.

Further amendments to the agreement were made in July 2009. In addition to the amendments made to the Bruce B floor price mechanism, described in the Energy Financial Analysis section of this MD&A, other changes to the contract with the OPA included the removal of a support payment cap for Bruce A. The cumulative support payments received by Bruce A, which are equal to the difference between the fixed prices under the OPA contract and spot market prices, were originally capped at $575 million until both Units 1 and 2 were restarted. The amendment provides that should either of the restarted Units 1 and 2 not be placed into commercial service by December 31, 2011, Bruce A will receive no further support payments and all output will receive spot prices until the restart is complete, at which point the Bruce A price will return to the then prevailing contract levels.

The July 2009 amendment also provided for deemed generation payments to Bruce Power at the contract prices when Bruce Power generation is reduced due to system curtailments on the IESO-controlled grid in Ontario.

Additionally, the capital cost-sharing mechanism for the refurbishment and restart of Bruce A Units 1 and 2 was amended to eliminate the requirement that the OPA share in any cost overruns exceeding $3.4 billion. Previously the OPA was responsible for 25 per cent of cost overruns above $3.4 billion through a future adjustment to the fixed price paid to Bruce Power for power generated by the Bruce A units.

The refurbishment and restart of Bruce A Units 1 and 2 is continuing with a focus on the reassembly of the reactors and related activities. As of December 31, 2009, Bruce A had incurred approximately $3.2 billion in costs for the refurbishment and restart of these units and approximately $0.2 billion for the refurbishment of Units 3 and 4. TCPL believes that the Company's share of the total capital cost to complete the Unit 1 and 2 refurbishment and restart program will be approximately $2 billion. The bulk of the highly technical, high-risk work on this project is now finished or nearing completion. Although a significant amount of work remains to be completed, most of it involves conventional power plant construction activity. A project optimization plan implemented by Bruce Power last year is achieving success in improving productivity. TCPL expects that Unit 2 will be restarted in mid-2011, with the Unit 1 restart following approximately four months later.

Bruce Power continues to advance an initiative to further extend the operating lives of Units 3 and 4. Unit 4 is now expected to continue to operate beyond 2018 and plans are in place to implement an extensive maintenance program that, would result in the life of Unit 3 being extended for a similar period of time.

Portlands Energy Portlands Energy was completed under budget and fully commissioned in April 2009. The power plant, which is 50 per cent owned by TCPL, is able to provide 550 MW of electricity under a 20 year Accelerated Clean Air Supply contract with the OPA.

Coolidge In August 2009, TCPL began construction of the US$500 million Coolidge generating station located near Phoenix, Arizona. The first of 12 gas-fired turbines began arriving on site in January 2010. The 575 MW, simple-cycle, natural gas-fired peaking power facility is expected to be in service in second quarter 2011. All of the power produced by the facility will be sold under a 20 year PPA to the Salt River Project Agricultural Improvement and Power District based in Phoenix, Arizona.

Halton Hills Construction of Halton Hills continued in 2009 and is nearing completion. The project is a 683 MW natural gas-fired power plant near Halton Hills, Ontario and is expected to be in operation in third quarter 2010 following commissioning, start-up and testing. TCPL expects to invest approximately $700 million in the project. Power from the facility will be sold to the OPA under a 20 year Clean Energy Supply contract.

Cartier Wind In third quarter 2009, construction activity began on the 212 MW Gros-Morne and 58 MW Montagne-Sèche wind farms. The Montagne-Sèche project and phase one of the Gros-Morne project (101 MW) are expected to be operational in 2011. Phase two of the Gros-Morne project (111 MW) is expected to be operational in 2012. Gros-Morne and Montagne-Sèche are the fourth and fifth Québec-based wind farms of the Cartier Wind project. Once they are complete, Cartier Wind, which is 62 per cent owned by TCPL, will be capable of producing 590 MW of electricity. All of the power produced by Cartier Wind is sold to Hydro-Québec under a 20 year PPA. In fourth quarter 2009, the proposed 150 MW Les Méchins wind farm, the sixth project in Cartier Wind, was cancelled due to the unavailability of cost-effective wind turbines and difficulty reaching acceptable agreements with private landowners. This decision has no impact on the other Cartier Wind projects.

Kibby Wind In October 2009, the first phase of the Kibby Wind power project, including 22 turbines capable of producing a combined 66 MW of power, was placed in service six weeks ahead of schedule and under budget. Construction continues on the 66 MW second phase of the project, which includes the installation of an additional 22 turbines. This phase is expected to be in service in third quarter 2010. Total cost of construction for both phases of the project is expected to be approximately US$350 million. The project is expected to be eligible for government incentive payments under the federal U.S. stimulus package.

Bécancour In June 2009, TCPL entered into an agreement with Hydro-Québec to continue to suspend all electricity generation from the Bécancour power plant through 2010. Hydro-Québec has the option, subject to certain conditions, to extend the suspension on an annual basis until such time as regional electricity demand levels recover. TCPL receives payments under this agreement similar to those that would have been received under the normal course of operation.

Oakville In September 2009, the OPA awarded TCPL a 20 year Clean Energy Supply contract to build, own and operate the 900 MW Oakville power generating station in Oakville, Ontario. TCPL expects to invest approximately $1.2 billion in the natural gas-fired, combined-cycle plant, which is anticipated to be in service in first quarter 2014.

Power Transmission Line Projects TCPL's open seasons for capacity on its proposed Zephyr and Chinook power transmission line projects closed in December 2009. A comprehensive review of the bids submitted for each project is underway. Each project would be capable of delivering primarily renewable (wind-generated) power originating in Wyoming (Zephyr) and Montana (Chinook) to Nevada.

Broadwater LNG In April 2009, the U.S. Department of Commerce issued a decision upholding New York State's objection to the proposed construction and operation of the Broadwater LNG project, a joint venture between TCPL and Shell Broadwater Holdings LLC. The Broadwater Energy partnership has scaled back near term activities and is assessing its future options with respect to this project.

ENERGY BUSINESS RISKS

Fluctuating Power and Natural Gas Market Prices TCPL operates in competitive power and natural gas markets in North America. Volatility in power and natural gas prices is caused by fluctuating supply and demand, and by general economic conditions. Energy's earnings from the sale of uncontracted volumes are subject to price volatility. Although Energy commits a significant portion of its supply to medium- to long-term sales contracts, it retains an amount of unsold supply in order to provide flexibility in managing the Company's portfolio of wholly owned assets.

Capacity Payments U.S. Power capacity payments are reset periodically each year and are affected by the start-up and retirement of power facilities and by fluctuations in demand.

Uncontracted Volumes Energy has uncontracted power sales volumes in Western Power and U.S. Power. With the 2008 acquisition of Ravenswood, the level of uncontracted sales volumes in U.S. Power significantly increased. Sales of uncontracted power volumes into the spot market are subject to market price volatility, which directly impacts earnings. In addition, as power sales contracts expire, any new contracts are entered into at the prevailing market prices. In 2009, prices realized on these new contracts were generally lower than in recent years due to the significant decrease in power prices in TCPL's core power markets.

Bruce B volumes are subject to a floor price mechanism. When the spot market price is above the floor price, Bruce B's non-contracted volumes are subject to spot price volatility. When spot prices are below the floor price, Bruce B receives the floor price. However, Bruce B's results during this period are still subject to the impact of fluctuating spot prices upon the settlement of contracted sales. All of the Bruce A output is sold into the Ontario wholesale power spot market under fixed contract price terms with the OPA and 100 per cent of Eastern Power sales volumes are sold under long-term contracts.

Energy's natural gas storage business is subject to fluctuating natural gas seasonal spreads generally determined by the differential in natural gas prices in the traditional summer injection and winter withdrawal seasons. As a result, the Company hedges capacity with a portfolio of contractual capacity sales commitments.

Liquidity Risk A decrease in the number and credit quality of counterparties may increase the Company's exposure to spot prices by reducing its ability to lock in forward sale prices at acceptable contract terms.

Plant Availability Maintaining plant availability is essential to the continued success of the Energy business. Plant operating risk is mitigated through a commitment to TCPL's operational excellence strategy, which is to provide low-cost, reliable operating performance at each of the Company's facilities. Unexpected plant outages, including unexpected delays in completing planned outages, could result in lower plant output and sales revenue, reduced capacity payments and margins, and increased maintenance costs. At certain times, unplanned outages may require power or natural gas purchases at market prices to ensure TCPL meets its contractual obligations.

Weather Extreme temperature and weather events in North America and the Gulf of Mexico often create price volatility and variable demand for power and natural gas. These events may also restrict the availability of power and natural gas. Seasonal changes in temperature can also affect the efficiency and output capability of natural gas-fired power plants. Variability in wind speeds may impact the earnings of Energy's wind assets.

Hydrology TCPL's power operations are subject to hydrology risk arising from the ownership of hydroelectric power generation facilities in the northeastern U.S. Weather changes, weather events, local river management and potential dam failures at these plants or upstream facilities pose potential risks to the Company.

Execution, Capital Cost and Permitting Energy's new construction programs in Ontario, Québec, Maine and Arizona, including its investment in Bruce Power, are subject to execution, capital cost and permitting risks.

Asset Commissioning Although each of TCPL's newly constructed assets goes through rigorous acceptance testing prior to being placed in service, there is a risk that these assets may have lower than expected availability or performance, especially in their first year of operations.

Regulation of Power Markets TCPL operates in both regulated and deregulated power markets. As power markets evolve across North America, there is the potential for regulatory bodies to implement new rules that could negatively affect TCPL 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 and attempts by others to take out-of-market actions to build excess generation that negatively affects the price of capacity or energy, or both. In addition, TCPL's development projects rely on an orderly permitting process and any disruption to that process can have negative effects on project schedules and costs. TCPL continues to monitor regulatory issues and regulatory reform and participate in and lead related discussions.

Refer to the Risk Management and Financial Instruments section of this MD&A for information on additional risks and managing risks in the Energy business.

ENERGY OUTLOOK

TCPL assumes that results from its Energy operations in 2010 will be materially consistent with those in 2009 and will include the positive impact of a full year of earnings from Portlands Energy and phase one of Kibby Wind, as well as incremental earnings from Halton Hills and phase two of Kibby Wind, which are expected to be commissioned in third quarter 2010.

The Company expects capacity prices in the New York City market, in which Ravenswood operates, to improve with the long-planned retirement of a power generating facility owned by the New York Power Authority which occurred at the end of January 2010. The positive impact from this facility's retirement may be partially offset by some reductions in demand in this market, driven by the economic downturn and the results of energy efficiency investments being made in the region.

The current economic climate continues to negatively affect demand, liquidity and prices in commodity markets in which TCPL's Energy segment operates. Earnings in Western Power, Bruce Power and U.S. Power are expected to be negatively impacted in the near term by the expiry of existing forward sale contracts as new contracts would generally be negotiated at lower prices.

Although TCPL has sold forward significant output from its power plants and Alberta PPAs, as well as capacity from its natural gas storage facilities, Energy's EBITDA in 2010 can be affected by changes in factors such as the spot market price of power, market heat rates, hydrology, capacity payments, natural gas storage spreads and unplanned outages. EBITDA from Energy's U.S. operations is also affected by changes in foreign currency exchange rates.

Other factors such as plant availability, regulatory changes, weather, currency movements and overall stability of the energy industry can also affect 2010 EBITDA. Refer to the Energy Business Risks section of this MD&A for a complete discussion of these factors.

Capital Expenditures Energy's total capital expenditures in 2009 were $1.5 billion. Energy's overall capital spending in 2010 is expected to be approximately $1.3 billion, including cash calls for the Bruce A refurbishment and restart project, and continued construction at Coolidge, Cartier Wind, Kibby Wind, Halton Hills and Oakville.

CORPORATE

Corporate EBIT losses for the year ended December 31, 2009 were $117 million compared to losses of $104 million and $102 million in 2008 and 2007, respectively. The increases in EBIT losses were primarily due to higher support services costs, reflecting a growing asset base.

OTHER INCOME STATEMENT ITEMS

INTEREST EXPENSE

Year Ended December 31 *(millions of dollars)*

	2009	2008	2007
Interest on long-term debt[(1)]	**1,285**	1,038	1,029
Other interest and amortization	**59**	65	
Capitalized interest	**(358)**	(141)	(68)
	986	962	961

(1) Includes interest for Junior Subordinated Notes

Interest expense in 2009 increased $24 million to $986 million from $962 million in 2008. The increase in interest on long-term debt reflected new debt issues of US$1.5 billion and $500 million in August 2008, US$2.0 billion in January 2009 and $700 million in February 2009. In addition, U.S. dollar-denominated interest expense increased in 2009 due to the impact of a stronger U.S. dollar. These increases were partially offset by higher capitalization of interest to finance the Company's larger capital spending program primarily due to the construction of Keystone and the acquisition in 2009 of the remaining ownership interest in Keystone from ConocoPhillips. Interest expense in 2009 was positively impacted by reduced losses from changes in the fair value of derivatives used to manage TCPL's exposure to fluctuating interest rates. Interest expense in 2008 of $962 million was $1 million higher than 2007 due to higher financial charges resulting from financing the Company's 2008 capital program, including the Ravenswood acquisition, and higher losses from changes in the fair value of derivatives used to manage the Company's exposure to rising interest rates which were offset by increased capitalization of interest to finance the Company's larger capital spending program.

Interest income and other was $119 million in 2009 compared to $42 million and $118 million in 2008 and 2007, respectively. The increase of $77 million in 2009 compared to 2008 was primarily due to the positive impact of a weakening U.S. dollar throughout 2009 on U.S. dollar working capital balances and higher gains from derivatives used to manage the Company's exposure to foreign exchange rate fluctuations. An increase in interest income due to higher cash balances held in 2009 than in 2008 was more than offset by lower interest rates. The decrease of $76 million in 2008 compared to 2007 was primarily due to lower gains from derivatives used to manage the Company's exposure to foreign exchange rate fluctuations and the negative impact of a strengthening U.S. dollar throughout 2008.

Income taxes were $376 million, $591 million and $483 million in 2009, 2008 and 2007, respectively. The decrease of $215 million in 2009 compared to 2008 was primarily due to reduced pre-tax earnings, higher income tax savings from income tax rate differentials and other positive income tax adjustments in 2009, including $30 million of favourable adjustments arising from a reduction in the Province of Ontario's corporate income tax rates. The increase in income tax expense of $108 million in 2008 compared to 2007 was primarily due to positive income tax adjustments recorded in 2007 and higher pre-tax earnings in 2008.

Non-controlling interests were $74 million in 2009 compared to $108 million and $75 million in 2008 and 2007, respectively. The decrease in 2009 compared to 2008 was primarily due to the non-controlling interests' portion of Portland's Calpine bankruptcy settlements in 2008, partially offset by higher PipeLines LP earnings and the impact of a stronger U.S. dollar in 2009. The increase in 2008 compared to 2007 was primarily due to the non-controlling interests' portion of Portland's Calpine bankruptcy settlements in 2008.

LIQUIDITY AND CAPITAL RESOURCES

TCPL's financial position remains sound and consistent with recent years as does its ability to generate cash in the short and long term to provide liquidity, maintain financial capacity and flexibility, and to provide for planned growth. TCPL's liquidity position remains solid, underpinned by predictable cash flow from operations, significant cash balances on hand from recent debt and common share issues, as well as committed revolving bank lines of US$1.0 billion, $2.0 billion, US$1.0 billion and US$300 million, maturing in November 2010, December 2012, December 2012 and February 2013, respectively. In addition, TCPL's proportionate share of capacity remaining available on committed bank facilities at TCPL-operated affiliates was $143 million with maturity dates from 2010 through 2012. The Company operates commercial paper programs in Canada and, as at December 31, 2009, had remaining capacity of $2.0 billion and US$4.0 billion Canadian debt and U.S. debt shelf prospectuses, respectively. TCPL's liquidity, market and other risks are discussed further in the Risk Management and Financial Instruments section of this MD&A.

SUMMARIZED CASH FLOW

Year ended December 31 *(millions of dollars)*

	2009	2008	2007
Funds generated from operations[1]	**3,044**	2,992	2,603
(Increase)/decrease in operating working capital	**(88)**	128	63
Net cash provided by operations	**2,956**	3,120	2,666

(1) Refer to the Non-GAAP Measures section of this MD&A for further discussion of funds generated from operations.

HIGHLIGHTS

Investing Activities

Capital expenditures and acquisitions, including assumed debt, totalled approximately $20 billion over the three year period ending December 31, 2009.

Dividends

On February 22, 2010, the Board of Directors of TCPL declared a dividend for the quarter ending March 31, 2010 in an aggregate amount equal to the quarterly dividend to be paid on TransCanada's issued and outstanding common shares at the close of business on March 31, 2010. The Board also declared regular dividends on TCPL's preferred shares.

CASH FLOW AND CAPITAL RESOURCES

Funds Generated from Operations

Funds generated from operations were $3.0 billion in 2009 compared to $3.0 billion and $2.6 billion, in 2008 and 2007, respectively. Funds generated from operations in 2009 were consistent with 2008 as increased earnings in 2009, net of increased pension contributions, were comparable to increased earnings in 2008 due to the $152 million after tax Calpine bankruptcy settlements in 2008. The Energy business and the Calpine bankruptcy settlements were the primary sources of the increase in 2008 compared to 2007.

Investing Activities

Capital expenditures totalled $5.4 billion in 2009 compared to $3.1 billion in 2008 and $1.7 billion in 2007. Expenditures in 2009 and 2008 related primarily to Keystone construction, the refurbishment and restart at Bruce A, construction of other new pipeline and power facilities, plus the expansion and maintenance of existing pipelines. In addition, in 2009, the Company incurred $3.3 billion of costs related to Keystone, including approximately $400 million related to the development of the Gulf Coast expansion. Expenditures in 2007 were related primarily to the refurbishment and restart at Bruce A, construction of new power plants in Canada and maintenance and capacity projects in the Pipelines business.

In August 2009, the Company purchased ConocoPhillips' remaining approximate 20 per cent interest in Keystone for US$553 million plus the assumption of US$197 million of short-term debt. Acquisitions in 2009 also included previous increases in ownership interest in Keystone from ConocoPhillips, discussed below. TCPL now owns 100 per cent of Keystone.

In 2008, TCPL entered into an agreement with ConocoPhillips to increase its equity ownership in Keystone to approximately 80 per cent from 50 per cent, with ConocoPhillips' equity ownership in Keystone being reduced concurrently to approximately 20 per cent from 50 per cent. In 2008 and prior to August 2009, TCPL funded 100 per cent of the construction expenditures until the participants' cumulative project capital contributions were aligned with their revised ownership interests. In 2009, prior to August, TCPL funded $1.3 billion of cash calls for Keystone, resulting in the Company acquiring an incremental increase in ownership of approximately 18 per cent for $313 million. In 2008, the Company funded $362 million of cash calls, resulting in an incremental increase in ownership of approximately 12 per cent for $176 million. TCPL's ownership interest was approximately 80 per cent and 62 per cent in August 2009 and at December 31, 2008, respectively.

TCPL acquired Ravenswood from National Grid plc on August 26, 2008 for US$2.9 billion.

In 2007, TCPL acquired ANR and an additional 3.6 per cent interest in Great Lakes from El Paso Corporation for US$3.4 billion, including US$491 million of assumed long-term debt. PipeLines LP acquired the remaining 46.4 per cent of Great Lakes from El Paso Corporation for US$942 million, including US$209 million of assumed long-term debt.

Financing Activities

In 2009, TCPL issued long-term debt of $3.3 billion and its proportionate share of long-term debt issued by joint ventures was $226 million. Also in 2009, the Company reduced its long-term debt by $1.0 billion, its proportionate share of the long-term debt of joint ventures by $246 million and notes payable by $244 million. This financing activity included the items noted below.

At December 31, 2009, total committed revolving and demand credit facilities of $5.2 billion were available to support the Company's commercial paper programs and for general corporate purposes. These unsecured credit facilities included the following:

A $2.0 billion committed, syndicated revolving TCPL credit facility, maturing December 2012. The facility was fully available at December 31, 2009 and supports TCPL's commercial paper program.

a US$300 million committed, syndicated revolving credit facility, guaranteed by TransCanada, maturing February 2013. This facility is part of the US$1.0 billion TransCanada PipeLine USA Ltd. (TCPL USA) credit facility discussed below under the heading 2007 Long-Term Debt Financing Activities. At December 31, 2009, this facility was fully drawn.

a US$1.0 billion committed, syndicated revolving TransCanada Keystone Pipeline, L.P. credit facility, guaranteed by TCPL, maturing November 2010 but extendible to November 2011 at the option of the borrower. The facility was fully available at December 31, 2009 and supports a commercial paper program dedicated to funding a portion of expenditures for Keystone and for Keystone general partnership purposes.

a US$1.0 billion committed, syndicated revolving TCPL USA credit facility established in fourth quarter 2009, maturing December 2012, with a one year extension at the option of the borrower. The facility is guaranteed by TransCanada

and was fully available at December 31, 2009. This facility will be used to partially fund the Company's capital program and for general corporate purposes.

demand lines totalling $805 million, which support the issuance of letters of credit and provide additional liquidity. The Company had used approximately $467 million of these demand lines for letters of credit at December 31, 2009.

The Company is well positioned to fund its existing capital program through its growing internally-generated cash flow and its continued access to capital markets. As demonstrated by the recent sale of North Baja to PipeLines LP, TCPL will also continue to examine opportunities for portfolio management, including a greater role for PipeLines LP, in financing its capital program.

In July 2009, TCPL sold North Baja to PipeLines LP. As part of the transaction, TCPL agreed to amend its incentive distribution rights with PipeLines LP. TCPL received aggregate consideration totalling approximately US$395 million from PipeLines LP, including US$200 million in cash and 6,371,680 common units of PipeLines LP. PipeLines LP utilized US$170 million of its US$250 million committed and available bank facility to partially fund this transaction, which resulted in TCPL's ownership in PipeLines LP increasing to 42.6 per cent. Subsequent to this transaction, TCPL's ownership in PipeLines LP decreased to 38.2 per cent due to PipeLines LP's public issuance of common units as discussed under the heading 2009 Equity Financing Activities in this section.

Related Party Debt Financing

Related party transactions consist of amounts due to and from TransCanada as well as accrued interest income and expense.

At December 31, 2009, TransCanada issued discount notes, maturing in June 2010, to TCPL for $2.0 billion (2008 $1.5 billion). Interest on the notes is equivalent to current commercial paper rates. These notes were used for general corporate purposes.

TranCanada has established a $2.5 billion, unsecured credit facility agreement with TCPL, bearing interest at the Bankers' Acceptance rate or Reuters prime rate plus 65 basis points, either at TCPL's option. The funds advanced under this agreement can be used to repay indebtedness, make partner contributions to Bruce Power A, or used for working capital and general corporate purposes. At December 31, 2009, $2.1 billion was outstanding on this credit facility (2008 $1.6 billion). This credit agreement matures on December 15, 2012.

In June 2009, TCPL increased a demand revolving credit facility with TransCanada to $1.5 billion or its U.S. dollar equivalent amount. The facility bears interest at the Royal Bank of Canada prime rate per annum or the U.S. base rate per annum and will be used for general corporate purposes. At December 31, 2009, $1.1 billion was outstanding on this facility (2008 $200 million).

In 2009, Interest Expense included $52 million (2008 $76 million; 2007 $72 million) of interest expense and $20 million (2008 $55 million; 2007 $30 million) of interest income as a result of transactions with TransCanada. At December 31, 2009 Accounts Payable included $2 million of interest payable to TransCanada (2008 $2 million) and $3 million of interest receivable from TransCanada (2008 $12 million).

Short-Term Debt Financing Activities

In June 2008, TCPL executed an agreement with a syndicate of banks for a US$1.5 billion committed, unsecured, one year bridge loan facility, which was extendible at the option of the Company for an additional six-month term. In August 2008, the Company used US$255 million from this facility to fund a portion of the Ravenswood acquisition and cancelled the remainder of the commitment. In February 2009, the US$255 million was repaid and the facility was cancelled.

2009 Long-Term Debt Financing Activities

In December 2009, TCPL filed a debt base shelf prospectus qualifying for the issuance of up to US$4.0 billion of debt securities in the U.S. This prospectus replaced a US$3.0 billion debt base shelf prospectus filed in January 2009, which had remaining capacity of US$1.0 billion. No amounts have been issued under the December 2009 base shelf prospectus.

In April 2009, TCPL filed a $2.0 billion Canadian Medium-Term Notes base shelf prospectus to replace a March 2007 $1.5 billion Canadian Medium-Term Notes base shelf prospectus, which expired in April 2009. No amounts have been issued under the April 2009 base shelf prospectus.

In February 2009, TCPL issued Medium-Term Notes of $300 million and $400 million maturing in February 2014 and February 2039, respectively, and bearing interest at 5.05 per cent and 8.05 per cent, respectively. The proceeds were used to fund the Alberta System and Canadian Mainline rate bases. These notes were issued by way of a pricing supplement under a Canadian $1.5 billion debt base shelf prospectus filed in March 2007.

In January 2009, TCPL issued Senior Unsecured Notes of US$750 million and US$1.25 billion maturing in January 2019 and January 2039, respectively, and bearing interest at 7.125 per cent and 7.625 per cent, respectively. The proceeds were used to partially fund TCPL's capital projects, retire maturing debt obligations and for general corporate purposes. These notes were issued by way of a prospectus supplement under a US$3.0 billion debt base shelf prospectus filed by TCPL in January 2009.

In September 2009, TQM issued $75 million of bonds maturing in September 2014 and bearing interest at 4.05 per cent.

In August 2009, Northern Border issued US$100 million of Senior Unsecured Notes maturing in August 2016 and bearing interest at 6.24 per cent.

In May 2009, Iroquois issued US$140 million of Senior Unsecured Notes maturing in May 2019 and bearing interest at 6.63 per cent.

In October 2009, the Company retired $250 million of 10.625 per cent debentures.

In February 2009, the Company retired $200 million of 4.10 per cent Medium-Term Notes.

In January 2009, the Company retired US$227 million of 6.49 per cent Medium-Term Notes.

In September 2009, Northern Border retired US$200 million of 7.75 per cent Senior Notes.

In August 2009, TQM retired $100 million of 6.50 per cent Series H Bonds.

2008 Long-Term Debt Financing Activities

In 2008, TCPL issued long-term debt of $2.2 billion, increased its notes payable by $1.7 billion and its proportionate share of long-term debt issued by joint ventures was $173 million. The Company also reduced its long-term debt by $840 million and its proportionate share of the long-term debt of joint ventures by $120 million. This financing activity included the items noted below.

In August 2008, TCPL issued $500 million of Medium-Term Notes maturing in August 2013 and bearing interest at 5.05 per cent. The proceeds from these notes were used to partially fund the Alberta System's capital program and for general corporate purposes. These notes were issued by way of pricing supplement under the Canadian $1.5 billion debt base shelf prospectus filed in March 2007.

In August 2008, TCPL issued US$850 million and US$650 million of Senior Unsecured Notes maturing in August 2018 and August 2038, respectively, and bearing interest at 6.50 per cent and 7.25 per cent, respectively. The proceeds from these notes were used to partially fund the Ravenswood acquisition and for general corporate purposes. These notes were issued by way of a prospectus supplement under a US$2.5 billion debt base shelf prospectus filed in September 2007, which was fully utilized following these issuances.

In June 2008, the Company retired $256 million of 5.84 per cent Medium-Term Notes and a $100 million 11.85 per cent debenture. In January 2008, the Company retired $105 million of 6.0 per cent Medium-Term Notes.

2007 Long-Term Debt Financing Activities

In 2007, TCPL issued long-term debt of $2.6 billion and junior subordinated notes of US$1.0 billion, and its proportionate share of long-term debt issued by joint ventures was $142 million. The Company also reduced its long-term debt by $1.1 billion, its notes payable by $412 million and its proportionate share of the long-term debt of joint ventures by $157 million. This financing activity included the items noted below.

In October 2007, TCPL issued US$1.0 billion of Senior Unsecured Notes maturing on October 15, 2037 and bearing interest at 6.2 per cent. These notes were issued under the US$2.5 billion debt base shelf prospectus filed by TCPL in September 2007.

In July 2007, TCPL exercised its rights to redeem the US$460 million 8.25 per cent Preferred Securities due 2047. The Preferred Securities were redeemed for cash, at par, as agreed to in a settlement for the Canadian Mainline. The foreign exchange gain realized on redemption of the securities will flow through to Canadian Mainline shippers over the five-year period of the settlement.

In April 2007, TCPL issued US$1.0 billion of Junior Subordinated Notes, maturing in 2067 and bearing interest at 6.35 per cent per year until May 15, 2017, when interest will convert to a floating interest rate of three-month LIBOR plus 221 basis points. The Junior Subordinated Notes are subordinated to all existing and future TCPL senior indebtedness, are effectively subordinated to all indebtedness and other obligations of TCPL, and are callable at TCPL's option at any time on or after May 15, 2017 at the principal amount plus accrued and unpaid interest. The notes were issued by way of prospectus supplement pursuant to a U.S. debt base shelf prospectus filed in March 2007.

In April 2007, Northern Border increased its five year bank facility to US$250 million from US$175 million. A portion of the bank facility was drawn to refinance US$150 million of Senior Notes that matured in May 2007, with the balance available to fund Northern Border's ongoing operations.

In March 2007, ANR Pipeline voluntarily withdrew the New York Stock Exchange listing of its 9.625 per cent debentures due 2021, 7.375 per cent debentures due 2024, and 7.0 per cent debentures due 2025. With the delisting, ANR Pipeline deregistered these securities with the SEC.

In February 2007, TCPL USA established the US$1.0 billion committed, unsecured credit facility, consisting of a US$700 million five year term loan, maturing in 2012 and a US$300 million extendible revolving facility, maturing in February 2013. The Company utilized US$1.0 billion from this facility and an additional US$100 million from an existing demand line to partially finance the ANR acquisition and increased ownership in Great Lakes, as well as its additional investment in PipeLines LP in 2007. The facility is guaranteed by TransCanada. There was an outstanding balance of US$700 million on the term loan at December 31, 2009 and 2008.

In February 2007, PipeLines LP increased the size of its syndicated revolving credit and term loan facility in connection with its Great Lakes acquisition. The amount available under the facility increased to US$950 million from US$410 million and consisted of a US$700 million senior term loan and a US$250 million senior revolving credit facility, with US$194 million of the available senior term loan amount being terminated upon closing of the Great Lakes acquisition. At December 31, 2009, US$475 million was outstanding on the senior term loan. The US$250 million senior revolving credit facility will terminate in December 2011.

In October 2007, the Company retired $150 million of 6.15 per cent Medium-Term Notes. In February 2007, the Company retired $275 million of 6.05 per cent Medium-Term Notes.

2009 Equity Financing Activities

In 2009, TCPL issued 51.5 million common shares to TransCanada for proceeds of approximately $1.7 billion. The proceeds of these issues were used to partially fund capital projects, for general corporate purposes and to repay short-term indebtedness.

On November 19, 2009, PipeLines LP completed a public offering of five million common units at a price of US$38.00 per unit, resulting in net proceeds to PipeLines LP of US$182 million. TCPL contributed an additional US$4 million to maintain its general partnership interest but did not purchase any units. Upon completion of this offering, TCPL's ownership interest in PipeLines LP was 38.2 per cent.

Commencing in 2007, TransCanada's Board of Directors authorized the issuance of common shares from treasury at a discount to participants in TransCanada's Dividend Reinvestment Plan (DRP). Under this plan, eligible TCPL preferred shareholders may reinvest their dividends and make optional cash payments to obtain TransCanada common shares. The DRP shares are provided to the participants at a discount to the average market price in the five days before dividend payment. The discount was set at two per cent commencing with the dividend payable in April 2007 and was increased to three per cent commencing with the dividend payable in January 2009. Prior to the April 2007 dividend, TransCanada purchased shares on the open market and provided them to DRP participants at cost. TransCanada reserves the right to alter the discount or return to purchasing shares on the open market at any time.

2008 Equity Financing Activities

In 2008, TCPL issued 66.3 million common shares to TransCanada for proceeds of approximately $2.4 billion. The proceeds were used to partially fund its capital projects, including Keystone, for general corporate purposes, and to repay short-term indebtedness.

2007 Equity Financing Activities

In 2007, TCPL issued 48.2 million common shares to TransCanada for proceeds of approximately $1.8 billion. The proceeds were used towards financing the acquisition of ANR and Great Lakes.

In February 2007, PipeLines LP completed a private placement offering of 17.4 million common units at a purchase price of US$34.57 per unit. TCPL acquired 50 per cent of the units for US$300 million and invested an additional US$12 million to maintain its general partnership ownership interest in PipeLines LP. The total private placement plus TCPL's additional investment resulted in gross proceeds to PipeLines LP of US$612 million, which were used to partially finance its Great Lakes acquisition.

Dividends

Cash dividends on common and preferred shares amounting to $998 million were paid in 2009 (2008 $817 million; 2007 $725 million). The increase in dividends paid each successive year was primarily due to a greater number of common shares outstanding.

On February 22, 2010, the Board of Directors of TCPL declared a dividend for the quarter ending March 31, 2010 in an aggregate amount equal to the quarterly dividend to be paid on TransCanada's issued and outstanding common shares at the close of business on March 31, 2010. The Board also declared regular dividends on TCPL's preferred shares.

Issuer Ratings

TCPL's issuer rating assigned by Moody's Investors Service (Moody's) is Baa1 with a stable outlook. On September 30, 2009, DBRS and Standard and Poor's (S&P) assigned ratings of Pfd-2 (low) and P-2, respectively, to TransCanada's cumulative redeemable first preferred shares, Series 1 and, in connection with the offering of the preferred shares, S&P assigned TransCanada an A- long-term corporate credit rating with a stable outlook. TCPL's senior unsecured debt is rated A with a stable outlook by DBRS, A3 with a stable outlook by Moody's, and A- with a stable outlook by S&P.

CONTRACTUAL OBLIGATIONS

Obligations and Commitments

At December 31, 2009, the Company had $16.7 billion of total long-term debt and $1.0 billion of junior subordinated notes, compared to $16.2 billion of total long-term debt and $1.2 billion of junior subordinated notes at December 31, 2008. TCPL's share of the total debt of joint ventures, including capital lease obligations, was $1.0 billion at December 31, 2009, compared to $1.1 billion at December 31, 2008. Total notes payable, including TCPL's proportionate share of the notes payable of joint ventures, were $1.7 billion at December 31, 2009 and December 31, 2008. TCPL has provided certain pro-rata guarantees related to the capital lease and performance obligations of Bruce Power and certain other partially owned entities.

CONTRACTUAL OBLIGATIONS
Year ended December 31 *(millions of dollars)*

		Payments Due by Period			
	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt[1]	18,443	677	2,240	1,930	13,596
Capital lease obligations	222	13	33	43	133
Operating leases[2]	862	74	150	147	491
Purchase obligations	11,882	3,433	2,963	1,502	3,984
Other long-term liabilities reflected on the balance sheet	2,738	14	2,099	35	590
	34,147	4,211	7,485	3,657	18,794

(1) Includes junior subordinated notes and long-term debt of joint ventures, excluding capital lease obligations.

(2) Represents future annual payments, net of sub-lease receipts, for various premises, services and equipment. The operating lease agreements for premises, services and equipment expire at various dates through 2052 with an option to renew certain lease agreements for one to ten years.

TCPL's commitments under the Alberta PPAs are considered to be operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Future payments under these PPAs have been excluded from operating leases in the above table, as these payments are dependent upon plant availability among other factors. TCPL's share of power purchased under the PPAs in 2009 was $384 million (2008 $398 million; 2007 $391 million).

At December 31, 2009, 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 were as follows:

PRINCIPAL REPAYMENTS
Year ended December 31 *(millions of dollars)*

		Payments Due by Period			
	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Due to TransCanada Corporation	2,069		2,069		
Long-term debt	16,664	478	2,099	1,879	12,208
Junior subordinated notes	1,036				1,036
Long-term debt of joint ventures	743	199	141	51	352
	20,512	677	4,309	1,930	13,596

INTEREST PAYMENTS
Year ended December 31 *(millions of dollars)*

		Payments Due by Period			
	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Due to TransCanada Corporation	79	26	53		
Long-term debt	16,625	1,120	2,127	1,960	11,418
Junior subordinated notes	498	66	133	133	166
Long-term debt of joint ventures	305	46	73	65	121
	17,507	1,258	2,386	2,158	11,705

At December 31, 2009, the Company's approximate future purchase obligations were as follows:

PURCHASE OBLIGATIONS[1]
Year ended December 31 *(millions of dollars)*

		Payments Due by Period			
	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Pipelines					
Transportation by others[2]	693	243	281	104	65
Capital expenditures[3][4]	2,043	1,417	621	5	
Other	67	8	12	10	37
Energy					
Commodity purchases[5]	6,533	877	1,235	1,189	3,232
Capital expenditures[3][6]	1,341	745	596		
Other[7]	1,161	117	209	188	647
Corporate					
Information technology and other	44	26	9	6	3
	11,882	3,433	2,963	1,502	3,984

(1) The amounts in this table exclude funding contributions to pension plans and funding to the APG.

(2) Rates are based on known 2010 levels. Beyond 2010, demand rates are subject to change. The purchase obligations in the table are based on known or contracted demand volumes only and exclude commodity charges incurred when volumes flow.

(3) Amounts are estimates and are subject to variability based on timing of construction and project enhancements. The Company expects to fund capital projects with cash from operations and, if necessary, new debt and equity.

(4) Capital expenditures are primarily related to the construction costs of Keystone, North Central Corridor, Guadalajara, Bison and other pipeline projects.

(5) 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.

(6) Capital expenditures are primarily related to TCPL's share of the construction and development costs of Oakville, Bruce Power, Coolidge, Halton Hills and phase two of Kibby Wind.

(7) Includes estimates of certain amounts that are subject to change depending on plant fired hours, the consumer price index, actual plant maintenance costs, plant salaries and changes in regulated rates for transportation.

TCPL and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business. Potential future commitments are discussed in the Pipelines Opportunities and Developments and Energy Opportunities and Developments sections in this MD&A.

In 2010, TCPL expects to make funding contributions of approximately $115 million for the defined benefit pension plans and approximately $28 million for the Company's other post-retirement benefit plans, savings plan and defined contribution pension plans. This represents a decrease from total funding contributions of $168 million in 2009 and is attributable primarily to significantly improved investment performance and to plan experience being different than expectations. TCPL's proportionate share of funding contributions expected to be made by joint ventures to their respective pension and other post-retirement benefit plans in 2010 is approximately $57 million and $6 million, respectively, compared to total contributions of $54 million in 2009.

The next actuarial valuation for the Company's pension and other post-retirement benefit plans will be carried out as at January 1, 2011. TCPL expects funding requirements for these plans to continue at the anticipated 2010 level for the next several years to amortize solvency deficiencies in addition to normal costs. The Company's 2010 net benefit cost is expected to increase modestly from 2009. However, future net benefit costs and the amount of funding contributions will be dependent on various factors, including investment returns achieved on plan assets, the level of interest rates, changes to plan design and actuarial assumptions, actual plan experience versus projections and amendments to pension plan regulations and legislation. Increases in the level of required plan funding are not expected to have a material impact on the Company's liquidity.

Bruce Power

Bruce A has signed commitments to third-party suppliers related to refurbishing and restarting Units 1 and 2. TCPL's share of these signed commitments, which extend over a two year period ending December 31, 2011, totals $295 million.

Aboriginal Pipeline Group

Under its agreement with the APG, TCPL agreed to finance the APG's one-third share of the MGP project's predevelopment costs. These costs are currently forecast to be between $150 million and $200 million, on a cumulative basis, depending on the pace of project development. As at December 31, 2009, the Company had advanced $143 million of this total. This agreement is discussed further in the Pipelines Opportunities and Developments section of this MD&A.

Contingencies

TCPL is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2009, the Company had recorded liabilities of approximately $67 million representing its estimate of the amount it expects to expend to remediate certain sites. However, additional liabilities may be incurred as more assessments occur and remediation efforts continue.

TCPL and its subsidiaries are subject to various 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

TCPL, Cameco Corporation and BPC have severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, a lease agreement and contractor services. The guarantees have terms ranging from 2018 to perpetuity. In addition, TCPL and BPC have severally guaranteed one-half of certain contingent financial obligations related to an agreement with the OPA to refurbish and restart Bruce A power generation units. The guarantees were provided as part of the reorganization of Bruce Power in 2005 and have terms ending in 2018 and 2019. In its 2009 decision to renew the operating licenses of Bruce Power, the Canadian Nuclear Safety Commission ordered that it was no longer necessary for the major partners of Bruce Power, including TCPL, to provide financial assurances to Bruce Power to support its license obligations. TCPL's share of the potential exposure under the remaining Bruce A and Bruce B guarantees was estimated at December 31, 2009 to be approximately $741 million. The fair value of these Bruce Power guarantees is estimated to be $82 million.The Company's exposure under certain of these guarantees is unlimited.

In addition to the guarantees for Bruce Power, the Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities related primarily to redelivery of natural gas, PPA payments and the payment of liabilities. TCPL's share of the potential exposure under these guarantees was estimated at December 31, 2009 to range from $351 million to a maximum of $632 million. The fair value of these guarantees is estimated to be $9 million which has been included in deferred amounts. The Company's exposure under certain of these guarantees is unlimited. For certain of these entities, any payments made by TCPL under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

FINANCIAL RISKS AND FINANCIAL INSTRUMENTS

Risk Management Overview

TCPL has exposure to market risk, counterparty credit risk and liquidity risk. TCPL engages in risk management activities with the objective being to protect earnings, cash flow and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure TCPL's risks and related exposures are in line with the Company's business objectives and risk tolerance. Risks are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by risk management and internal audit personnel. The Board of Directors' Audit Committee oversees how management monitors compliance with risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework. Internal audit personnel assist the Audit Committee in its oversight role by performing regular and ad-hoc reviews of risk management controls and procedures, the results of which are reported to the Audit Committee.

Market Risk

The Company constructs and invests in large infrastructure projects, purchases and sells energy commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. These activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which affect the Company's earnings and the value of the financial instruments it holds.

The Company uses derivatives as part of its overall risk management strategy to manage the exposure to market risk that results from these activities. Derivative contracts used to manage market risk generally consist of the following:

- Forwards and futures contracts contractual agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future. TCPL enters into foreign exchange and commodity forwards and futures to mitigate the impact of volatility in foreign exchange rates and commodity prices.

- Swaps contractual agreements between two parties to exchange streams of payments over time according to specified terms. The Company enters into interest rate, cross-currency and commodity swaps to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.

- Options contractual agreements to convey the right, but not the obligation, of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. The Company enters into option agreements to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.

Commodity Price Risk

The Company is exposed to commodity price movements as part of its normal business operations, particularly in relation to the prices of electricity, natural gas and oil products. A number of strategies are used to mitigate these exposures, including the following:

- Subject to its overall risk management strategy, the Company commits a significant portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to mitigate price risk in its asset portfolio.

- The Company purchases a portion of the natural gas and oil products required for its power plants or enters into contracts that base the sales price of electricity on the cost of natural gas, effectively locking in a margin. A significant portion of the electricity needed to fulfill the Company's power sales commitments is fulfilled through power generation or purchased through contracts, thereby reducing the Company's exposure to fluctuating commodity prices.

- The Company enters into offsetting or back-to-back positions using derivative financial instruments to manage price risk exposure in power and natural gas commodities created by certain fixed and variable pricing arrangements for different pricing indices and delivery points.

The Company assesses its commodity contracts and derivative instruments used to manage commodity risk to determine the appropriate accounting treatment. Contracts, with the exception of leases, have been assessed to determine whether they or certain aspects of them meet the definition of a derivative. Certain commodity purchase and sale contracts are derivatives but are not within the scope of Canadian Institute of Chartered Accountants (CICA) Handbook Section 3855 "Financial Instruments Recognition and Measurement", as they were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's expected purchase, sale or usage requirements. Certain other contracts are not within the scope of Section 3855 as they are considered to meet other exemptions.

TCPL manages its exposure to seasonal natural gas price spreads in its natural gas storage business by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. TCPL simultaneously enters into a forward purchase of natural gas for injection into storage and an offsetting forward sale of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to natural gas price movements. Fair value adjustments recorded each period on proprietary natural gas inventory in storage and these forward contracts may not be representative of the amounts that will be realized on settlement.

Natural Gas Inventory Price Risk

At December 31, 2009, the fair value of proprietary natural gas inventory in storage, as measured using a weighted average of forward prices for the following four months less selling costs, was $73 million (2008 $76 million). The change in fair value of proprietary natural gas inventory in storage in 2009 resulted in a net pre-tax unrealized gain of $3 million (2008 unrealized loss of $7 million; 2007 nil), which was recorded as an increase to Revenues and Inventories. The net change in fair value of natural gas forward purchase and sales contracts in 2009 resulted in a net pre-tax unrealized loss of $2 million (2008 unrealized gain of $7 million; 2007 unrealized gain of $10 million), which was recorded as a decrease in revenues.

Foreign Exchange and Interest Rate Risk

Foreign exchange and interest rate risk is created by fluctuations in the fair value or cash flow of financial instruments due to changes in foreign exchange rates and market interest rates.

A portion of TCPL's earnings from its Pipelines and Energy segments is generated in U.S. dollars and, as such, movement of the Canadian dollar relative to the U.S. dollar can affect TCPL's earnings. This foreign exchange impact is offset by certain related debt and financing costs being denominated in U.S. dollars and by the Company's hedging activities. TCPL currently has a greater exposure to U.S. currency fluctuations than in prior years due to significant growth in its U.S. operations, partially offset by increased levels of U.S. dollar-denominated debt.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to its debt and other U.S. dollar-denominated transactions, and to manage the interest rate exposures of the Canadian Mainline, Alberta System and Foothills operations. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms. These gains and losses are deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers in accordance with the terms of the shipping agreements.

TCPL has floating interest rate debt, which subjects it to interest rate cash flow risk. The Company uses a combination of interest rate swaps and options to manage its exposure to this risk.

On a consolidated basis, the impact of changes in the U.S. dollar on U.S. Pipelines and Energy earnings is largely offset by the impact on U.S. dollar interest expense. The resultant net exposure is managed using derivatives, effectively reducing the Company's exposure to changes in foreign exchange rates.

Net Investment in Self-Sustaining Foreign Operations

The Company hedges its net investment in self-sustaining foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, forward foreign exchange contracts and foreign exchange options. At December 31, 2009, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $7.9 billion (US$7.6 billion) (2008 $7.2 billion (US$5.9 billion)) and a fair value of $9.8 billion (US$9.3 billion) (2008 $5.9 billion (US$4.8 billion)). At December 31, 2009, $96 million was included in Intangibles and Other Assets (2008 $254 million in Deferred Amounts) for the fair value of the forwards, swaps and options used to hedge the Company's net U.S. dollar investment in foreign operations.

The fair values and notional or principal amounts for the derivatives designated as a net investment hedge were as follows:

Asset/(Liability)
December 31 *(millions of dollars)*

	2009		2008	
	Fair Value[1]	**Notional or Principal Amount**	Fair Value[1]	Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2010 to 2014)	**86**	**U.S. 1,850**	(218)	U.S. 1,650
U.S. dollar forward foreign exchange contracts (maturing 2010)	**9**	**U.S. 765**	(42)	U.S. 2,152
U.S. dollar options (maturing 2010)	**1**	**U.S. 100**	6	U.S. 300
	96	**U.S. 2,715**	(254)	U.S. 4,102

(1) Fair values equal carrying values.

VaR Analysis

TCPL uses a Value-at-Risk (VaR) methodology to estimate the potential impact resulting from its exposure to market risk on its open liquid positions. VaR estimates the potential change in pre-tax earnings over a given holding period for a specified confidence level. The VaR number calculated and used by TCPL reflects a 95 per cent probability that the daily change resulting from normal market fluctuations in its open liquid positions will not exceed the reported VaR. The VaR methodology is a statistically-calculated, probability-based approach that takes into consideration market volatilities as well as risk diversification by recognizing offsetting positions and correlations among products and markets. Risks are measured across all products and markets, and risk measures are aggregated to arrive at a single VaR number.

There is currently no uniform industry methodology for estimating VaR. The use of VaR has limitations because it is based on historical correlations and volatilities in commodity prices, interest rates and foreign exchange rates, and assumes that future price movements will follow a statistical distribution. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR.

TCPL's estimation of VaR includes wholly owned subsidiaries and incorporates relevant risks associated with each market or business unit. The calculation does not include the Pipelines segment as the rate-regulated nature of the pipeline business reduces the impact of market risks. TCPL's Board of Directors has established a VaR limit, which is monitored on an ongoing basis as part of the Company's risk management policy. TCPL's consolidated VaR was $12 million at December 31, 2009 (2008 $23 million). The decline from December 31, 2008 was primarily due to decreased prices and lower open positions in the U.S. power portfolio.

Counterparty Credit Risk

Counterparty credit risk represents the financial loss the Company would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of its contracts with the Company.

Counterparty credit risk is managed through established credit management techniques, including conducting financial and other assessments to establish and monitor a counterparty's creditworthiness, setting exposure limits, monitoring exposures against these limits, using master netting arrangements and obtaining financial assurances where warranted. In general, financial assurances include guarantees, letters of credit and cash. The Company monitors and manages its concentration of counterparty credit risk on an ongoing basis. The Company believes these measures minimize its counterparty credit risk but there is no certainty that they will protect it against all material losses.

TCPL's maximum counterparty credit exposure with respect to financial instruments at the balance sheet date consisted primarily of non-derivative financial assets such as accounts receivable, loans and notes receivable, as well as the fair value of derivative assets. Within these balances, the Company does not have significant concentrations of counterparty credit risk with any individual counterparties and the majority of counterparty credit exposure is with counterparties who are investment grade. At December 31, 2009, there were no significant amounts past due or impaired.

TCPL has significant credit and performance exposures to financial institutions as they provide committed credit lines and cash deposit facilities, critical liquidity in the foreign exchange derivative, interest rate derivative and energy wholesale markets, and letters of credit to mitigate TCPL's exposure to non-creditworthy counterparties.

As a level of uncertainty continues to exist in the global financial markets, TCPL continues to closely monitor and reassess the creditworthiness of its counterparties. This has resulted in TCPL reducing or mitigating its exposure to certain counterparties where it was deemed warranted and permitted under contractual terms. As part of its ongoing operations, TCPL must balance its market and counterparty credit risks when making business decisions.

Certain subsidiaries of Calpine filed for bankruptcy protection in both Canada and the U.S. in 2005. Gas Transmission Northwest Corporation (GTNC) and Portland reached agreements with Calpine for allowed unsecured claims in the Calpine bankruptcy. In February 2008, GTNC and Portland received initial distributions of 9.4 million common shares and 6.1 million common shares, respectively, of Calpine, which represented approximately 85 per cent of their agreed-upon claims. In 2008, these shares were sold into the open market and resulted in total pre-tax gains of $279 million. Claims by NGTL and Foothills Pipe Lines (South B.C.) Ltd. for $32 million and $44 million, respectively, were received in cash in January 2008 and were passed on to shippers on these systems in 2008 and 2009.

Liquidity Risk

Liquidity risk is the risk that TCPL will not be able to meet its financial obligations when due. The Company's approach to managing liquidity risk is to ensure that, under both normal and stressed conditions, it always has sufficient cash and credit facilities to meet its obligations when due without incurring unacceptable losses or damage to the Company's reputation.

Management continuously forecasts cash flows for a period of 12 months to identify financing requirements. These requirements are then managed through a combination of committed and demand credit facilities and access to capital markets, as discussed under the heading Capital Management below.

At December 31, 2009, the Company had committed revolving bank lines of US$1.0 billion, $2.0 billion, US$1.0 billion and US$300 million maturing November 2010, December 2012, December 2012 and February 2013, respectively. At December 31, 2009, the US$300 million facility was fully drawn and no draws were made on any of the other facilities. The Company has maintained continuous access to the Canadian commercial paper market on competitive terms.

The Company has access to capital markets under the following prospectuses:

- In December 2009, TCPL filed a US$4.0 billion debt base shelf prospectus qualifying for the issuance of up to US$4.0 billion of debt securities in the U.S. At December 31, 2009, no amounts were issued under the base shelf prospectus.

- In April 2009, TCPL filed a $2.0 billion Medium-Term Notes base shelf prospectus in Canada. At December 31, 2009, no amounts were issued under this base shelf prospectus.

Capital Management

The primary objective of capital management is to ensure TCPL has strong credit ratings to support its businesses and maximize shareholder value. In 2009, the overall objective and policy for managing capital remained unchanged from the prior year.

TCPL manages its capital structure in a manner consistent with the risk characteristics of the underlying assets. The Company's management considers its capital structure to consist of net debt, non-controlling interests and shareholders' equity. Net debt is comprised of notes payable, long-term debt and junior subordinated notes less cash and cash equivalents. Net debt only includes obligations that the Company controls and manages. Consequently, it does not include cash and cash equivalents, notes payable and long-term debt of TCPL's joint ventures. The Company's capital structure was as follows:

December 31 *(millions of dollars)*	**2009**	2008
Notes payable	**1,678**	1,685
Due to TransCanada, net	**1,224**	292
Long-term debt	**16,664**	16,154
Junior subordinated notes	**1,036**	1,213
Cash and cash equivalents	**(878)**	(1,109)
Net debt	**19,724**	18,235
Non-controlling interests	**785**	805
Shareholders' equity	**14,872**	12,963
Total equity	**15,657**	13,768
Total capital	**35,381**	32,003

Fair Values

Certain financial instruments included in cash and cash equivalents, accounts receivable, intangibles and other assets, due to/from TransCanada Corporation, notes payable, accounts payable, accrued interest and deferred amounts have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity. 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 oil products derivatives has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques are used. Credit risk has been taken into consideration when calculating the fair value of derivatives.

The fair value of the Company's long-term debt was estimated based on quoted market prices for the same or similar debt instruments and, when such information was not available, was estimated by discounting future payments of interest and principal at estimated interest rates that were made available to the Company.

Non-Derivative Financial Instruments Summary

The carrying and fair values of non-derivative financial instruments were as follows:

December 31 *(millions of dollars)*

	2009		2008	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial Assets[1]				
Cash and cash equivalents	**979**	**979**	1,300	1,300
Accounts receivable, intangibles and other assets[2][3]	**1,433**	**1,484**	1,427	1,427
Due from TransCanada Corporation	**845**	**845**	1,329	1,329
Available-for-sale assets[2]	**23**	**23**	27	27
	3,280	**3,331**	4,083	4,083
Financial Liabilities[1][3]				
Notes payable	**1,687**	**1,687**	1,702	1,702
Accounts payable and deferred amounts[4]	**1,532**	**1,532**	1,364	1,364
Due to TransCanada Corporation	**2,069**	**2,069**	1,621	1,621
Accrued interest	**380**	**380**	361	361
Long-term debt	**16,664**	**19,377**	16,154	15,337
Junior subordinated notes	**1,036**	**976**	1,213	815
Long-term debt of joint ventures	**965**	**1,025**	1,076	1,052
	24,333	**27,046**	23,491	22,252

(1) Consolidated net income in 2009 included $6 million (2008 $15 million) for fair value adjustments related to interest rate swap agreements on US$250 million (2008 US$200 million and $50 million) of long-term debt. There were no other unrealized gains or losses from fair value adjustments to these financial instruments.

(2) At December 31, 2009, the Consolidated Balance Sheet included financial assets of $968 million (2008 $1,280 million) in accounts receivable and $488 million (2008 $174 million) in intangibles and other assets.

(3) Recorded at amortized cost, except for certain long-term debt and notes receivable which are adjusted to fair value.

(4) At December 31, 2009, the Consolidated Balance Sheet included financial liabilities of $1,507 million (2008 $1,342 million) in accounts payable and $25 million (2008 $22 million) in deferred amounts.

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2009 is as follows:

December 31 (all amounts in millions unless otherwise indicated)

	2009				
	Power	**Natural Gas**	**Oil Products**	**Foreign Exchange**	**Interest**
Derivative Financial Instruments Held for Trading[1]					
Fair Values[2]					
Assets	**$150**	**$107**	**$5**	**$**	**$25**
Liabilities	**$(98)**	**$(112)**	**$(5)**	**$(66)**	**$(68)**
Notional Values					
Volumes[3]					
Purchases	**15,275**	**238**	**180**		
Sales	**13,185**	**194**	**180**		
Canadian dollars					**574**
U.S. dollars				**U.S. 444**	**U.S. 1,325**
Cross-currency				**227/U.S. 157**	
Net unrealized gains/(losses) in the year	**$3**	**$(5)**	**$1**	**$3**	**$27**
Net realized gains/(losses) in the year	**$70**	**$(76)**	**$**	**$36**	**(22)**
Maturity dates	**2010 - 2015**	**2010 - 2014**	**2010**	**2010 - 2012**	**2010 - 2018**
Derivative Financial Instruments in Hedging Relationships[4][5]					
Fair Values[2]					
Assets	**$175**	**$2**	**$**	**$**	**$15**
Liabilities	**$(148)**	**$(22)**	**$**	**$(43)**	**$(50)**
Notional Values					
Volumes[3]					
Purchases	**13,641**	**33**			
Sales	**14,311**				
U.S. dollars				**U.S. 120**	**U.S. 1,825**
Cross-currency				**136/U.S. 100**	
Net realized gains/(losses) in the year	**$156**	**$(29)**	**$**	**$**	**$(37)**
Maturity dates	**2010 - 2015**	**2010 - 2014**		**2010 - 2014**	**2010 - 2020**

(1) All derivative financial instruments in the held-for-trading classification have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

(2) Fair values equal carrying values.

(3) Volumes for power, natural gas and oil products derivatives are in GWh, Bcf and thousands of barrels, respectively.

(4) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $4 million and a notional amount of US$150 million. Net realized gains on fair value hedges for December 31, 2009 were $4 million and were included in interest expense. In 2009, the Company did not record any amounts in net income related to ineffectiveness for fair value hedges.

(5)

In 2009, net income included losses of $5 million for the changes in fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2009, there were no gains or losses included in net income for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

The anticipated timing of settlement of the derivative contracts assumes constant commodity prices, interest rates and foreign exchange rates from December 31, 2009. Settlements will vary based on the actual value of these factors at the date of settlement. The anticipated timing of settlement of these contracts is as follows:

Year ended December 31 *(millions of dollars)*	Total	2010	2011 and 2012	2013 and 2014	2015 and Thereafter
Derivative financial instruments held for trading					
Assets	287	201	73	11	2
Liabilities	(349)	(233)	(85)	(27)	(4)
Derivative financial instruments in hedging relationships					
Assets	288	142	106	35	5
Liabilities	(263)	(106)	(89)	(66)	(2)
	(37)	4	5	(47)	1

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2008 is as follows:

December 31 (all amounts in millions unless otherwise indicated)

	2008				
	Power	Natural Gas	Oil Products	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading					
Fair Values[1]					
Assets	$132	$144	$10	$41	$57
Liabilities	$(82)	$(150)	$(10)	$(55)	$(117)
Notional Values					
Volumes[2]					
Purchases	4,035	172	410		
Sales	5,491	162	252		
Canadian dollars					1,016
U.S. dollars				U.S. 479	U.S. 1,575
Japanese yen (in billions)				JPY 4.3	
Cross-currency				227/U.S. 157	
Net unrealized gains/(losses) in the year	$24	$(23)	$1	$(9)	$(61)
Net realized gains/(losses) in the year	$23	$(2)	$1	$6	$13
Maturity dates	2009 - 2014	2009 - 2011	2009	2009 - 2012	2009 - 2018
Derivative Financial Instruments in Hedging Relationships[3][4]					
Fair Values[1]					
Assets	$115	$	$	$2	$8
Liabilities	$(160)	$(18)	$	$(24)	$(122)
Notional Values					
Volumes[2]					
Purchases	8,926	9			
Sales	13,113				
Canadian dollars					50
U.S. dollars				U.S. 15	U.S. 1,475
Cross-currency				136/U.S. 100	
Net realized (losses)/gains in the year	$(56)	$15	$	$	$(10)
Maturity dates	2009 - 2014	2009 - 2011		2009 - 2013	2009 - 2019

(1) Fair values equal carrying values.

(2) Volumes for power, natural gas and oil products derivatives are in GWh, Bcf and thousands of barrels, respectively.

(3) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $8 million and notional amounts of $50 million and US$50 million. Net realized gains on fair value hedges at December 31, 2008 were $1 million. In 2008, the Company did not record any amounts in net income related to ineffectiveness for fair value hedges.

(4) In 2008, net income included losses of $6 million for changes in fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2008, there were no gains or losses included in net income for discontinued cash flow hedges.

A 10 per cent increase or 10 per cent decrease in commodity prices, with all other variables held constant, would cause an $18 million decrease or an $18 million increase, respectively, in the fair value of derivative financial instruments outstanding as at December 31, 2009.

A 100 basis points increase or 100 basis points decrease in the letter of credit rate, with all other variables held constant, would cause a $6 million increase or a $6 million decrease, respectively, in the fair value of guarantee liabilities outstanding as at December 31, 2009. Similarly, the effect of a 100 basis points increase or 100 basis points decrease in the discount rate on the fair value of guarantee liabilities outstanding as at December 31, 2009 would cause a $2 million decrease in the liability or a $2 million increase in the liability, respectively.

Balance Sheet Presentation of Derivative Financial Instruments

The fair value of the derivative financial instruments in the Company's Balance Sheet was as follows:

December 31 (millions of dollars)	**2009**	2008
Current		
Other current assets	**315**	318
Accounts payable	**(340)**	(298)
Long-term		
Intangibles and other assets	**260**	191
Deferred amounts	**(272)**	(694)

OTHER RISKS

Development Projects and Acquisitions

TCPL continues to focus on growing its Pipelines and Energy operations through greenfield development projects and acquisitions. TCPL capitalizes costs incurred on certain of its projects during the development period prior to construction when the project meets specific criteria and is expected to proceed through to completion. The related capital costs of a project that does not proceed through to completion are expensed at the time it is discontinued. There is a risk with respect to TCPL's acquisition of assets and operations that certain commercial opportunities and operational synergies may not materialize as expected and would subsequently be subject to an impairment writedown.

Health, Safety and Environment Risk Management

Health, safety and environment (HS&E) are top priorities in all of TCPL's operations and activities in these areas are guided by the Company's HS&E Commitment Statement. The Commitment Statement outlines guiding principles for a safe and healthy environment for TCPL's employees, contractors and the public, and for TCPL's commitment to protect the environment. All employees are held responsible and accountable for HS&E performance. The Company is committed to being an industry leader in conducting its business so that it meets or exceeds all applicable laws and regulations, and minimizes risk to people and the environment. The Company is committed to tracking and improving its HS&E performance, and to promoting safety on and off the job in the belief that all occupational injuries and illnesses are preventable. TCPL endeavours to do business with companies and contractors that share its perspective on HS&E performance and to influence them to improve their collective performance. TCPL is committed to respecting the diverse environments and cultures in which it operates and to supporting open communication with the public, policy makers, scientists and public interest groups.

TCPL is committed to ensuring compliance with its internal policies and legislated requirements. The HS&E Committee of TCPL's Board of Directors monitors compliance with the Company's HS&E corporate policy through regular reporting. TCPL's HS&E management system is modeled on the International Organization for Standardization's (ISO) standard for environmental management systems, ISO 14001, and focuses resources on the areas of significant risk to the organization's HS&E business activities. Management is informed regularly of all important HS&E operational issues and initiatives through formal reporting processes. TCPL's HS&E management system and performance are assessed by an independent outside firm every three years. The most recent assessment occurred in December 2009 and did not identify any material issues. The HS&E management system is subject to ongoing internal review to ensure that it remains effective as circumstances change.

In 2009, employee and contractor health and safety performance continued to be a top priority. TCPL's objective is a health and safety performance consistent with top quartile companies in its sectors. Overall, the Company's safety frequency rates in 2009 continued to be better than most industry benchmarks.

The safety and integrity of the Company's existing and newly developed infrastructure also continued to be top priorities. All new assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are not brought into service until all necessary requirements are satisfied. The Company expects to spend approximately $181 million in 2010 for pipeline integrity on its wholly owned pipelines, which is $10 million higher than in 2009 primarily due to increased levels of in-line pipeline inspection on all systems. Under the approved regulatory models in Canada, pipeline integrity expenditures on NEB regulated pipelines are treated on a flow-through basis and, as a result, have no impact on TCPL's earnings. Under the Keystone contracts, pipeline integrity expenditures are recovered through the tolling mechanism and, as a result, have no impact on TCPL's earnings. Expenditures for GTN may also be recovered through a cost recovery mechanism in its rates. TCPL's pipeline safety record in 2009 continued to be above industry benchmarks. TCPL experienced three pipeline breaks in 2009. The first occurred in a remote part of northern Alberta. The other two occurred in rural parts of northern Ontario. The breaks resulted in minimal impact with no injuries and only minor property damage in one of the incidents. All three incidents were subject to a Level 3 investigation by the Transportation Safety Board of Canada. Spending associated with public safety on the Energy assets is focused primarily on the Company's hydro dams and associated equipment, and is consistent with previous years.

Environment

TCPL's facilities are subject to various federal, provincial, state and local statutes and regulations, including requirements to establish compliance and remediation obligations. Compliance obligations can result in significant costs associated with installing and maintaining pollution controls, fines and penalties resulting from any failure to comply, and potential limitations on operations. Remediation obligations can result in significant costs associated with the investigation and remediation of contaminated properties, some of which have been designated as Superfund sites by the U.S. Environmental Protection Agency under the *Comprehensive Environmental Response, Compensation and Liability Act*, and with damage claims arising out of the contamination of properties. It is not possible for the Company to estimate the amount and timing of all future expenditures related to environmental matters due to:

- Uncertainties in estimating pollution control and clean-up costs, including at sites where only preliminary site investigation or agreements have been completed;
- the potential discovery of new sites or additional information at existing sites;
- the uncertainty in quantifying liability under environmental laws that impose joint and several liability on all potentially responsible parties;
- the evolving nature of environmental laws and regulations, including the interpretation and enforcement thereof; and
- the potential for litigation on existing or discontinued assets.

Environmental risks from TCPL's operating facilities typically include: air emissions, such as nitrogen oxides, particulate matter and greenhouse gases; potential impacts on land, including land reclamation or restoration following construction; the use, storage or release of chemicals or hydrocarbons; the generation, handling and disposal of wastes and hazardous wastes; and water impacts such as uncontrolled water discharge. Environmental controls including physical design, programs, procedures and processes are in place to effectively manage these risks. TCPL has ongoing inspection programs designed to keep all of its facilities in compliance with environmental requirements and the Company is confident that its systems are in material compliance with the applicable requirements.

In 2009, TCPL conducted environmental risk assessments and remediation work, as well as various retirement, reclamation and restoration activities on its Canadian and U.S. facilities. At December 31, 2009, TCPL had recorded liabilities of approximately $91 million (2008 $86 million) for remediation obligations and compliance costs associated with greenhouse gas (GHG) legislation. The Company believes it has considered all necessary contingencies and established appropriate reserves for environmental liabilities. However, there is the risk that unforeseen matters may arise requiring the Company to set aside additional amounts.

TCPL is not aware of any material outstanding orders, claims or lawsuits against the Company in relation to the release or discharge of any material into the environment or in connection with environmental protection.

North American climate change policy continues to evolve at regional and national levels. While recent political and economic events may significantly affect the scope and timing of new measures that are put in place, TCPL anticipates that most of the Company's facilities in Canada and the U.S. are or will be captured under federal or regional climate change regulations to manage industrial GHG emissions.

In 2009, the Company owned assets in three Canadian provinces where regulations exist to address industrial GHG emissions. TCPL has put in place procedures to address these regulations.

In Alberta, under the Specified Gas Emitters Regulation, industrial facilities are required to reduce GHG emissions intensities by 12 per cent, effective July 2007. TCPL's Alberta-based facilities are subject to this regulation, as are the Sundance and Sheerness coal-fired power facilities with which TCPL has PPAs. As an alternative to reducing emissions intensities, compliance can be achieved through the retirement of offsets or payments to a technology fund at a cost of $15 per tonne of carbon dioxide (CO_2) in excess of the mandated reduction. A program is in place to manage the compliance costs incurred by these assets as a result of the regulation. Compliance costs on the Alberta System are recovered through tolls paid by customers. Recovery of compliance costs at the Company's power generation facilities in Alberta is dependent ultimately on market prices for electricity. TCPL has estimated and recorded costs of $17 million for 2009. These costs will be finalized when compliance reports are submitted in March 2010.

The hydrocarbon royalty in Québec is collected by the natural gas distributor on behalf of the Québec government through a green fund contribution charge on gas consumed. In 2009, the cost pertaining to the Bécancour facility arising from the hydrocarbon royalty was less than $1 million as a result of an agreement between TCPL and Hydro- Québec to temporarily suspend the facility's power generation. The cost is expected to increase when the plant returns to service.

B.C.'s carbon tax, which came into effect in mid-2008, applies to CO_2 emissions arising from fossil fuel combustion. Compliance costs for fuel combustion at the Company's compressor and meter stations in B.C. are recovered through tolls paid by customers. Costs related to the carbon tax in 2009 were $3 million. The cost per tonne of CO_2 was $15 in 2009 and will increase to $20 per tonne and $25 per tonne in 2010 and 2011, respectively.

TCPL has assets located in provinces where members of the Western Climate Initiative (WCI) have drafted regulations that apply to industrial GHG emitters. The Canadian WCI members include B.C., Manitoba, Ontario and Québec. The draft climate change strategies are expected to come into effect in 2012 and are expected to affect TCPL's pipeline and power facilities. The details of how these provincial programs will align with the Canadian government's climate change policies remain uncertain.

Seven western U.S. states, along with the four Canadian provinces discussed above, are focused on the implementation of a cap and trade program under the WCI. Members of the WCI have set a GHG emission reduction target of 15 per cent below 2005 levels by 2020. California, a WCI founding member, has released draft cap and trade regulations that, if enacted, are anticipated to have an impact on the Company's pipeline assets in the state. The financial implications to TCPL are not expected to be material. Under the current form of draft regulations in Washington and Oregon it is expected that there will not be a significant cost of compliance in these states. TCPL will continue to monitor these developments.

The Canadian government has continued to express interest in pursuing a harmonized continental climate change strategy. In January 2010, Environment Canada presented a revised target to the United Nations Framework Convention on Climate Change as part of its submission for the *Copenhagen Accord*. The submitted target represents a 17 per cent reduction in GHG emissions by 2020 relative to 2005 levels. The submission states that Canada will align with the final economy-wide emissions targets of the U.S. in enacted legislation. The Company expects that pipeline and power generation emissions will be subject to reduction targets for industrial emitters.

Emission allowances or credits purchased for compliance are recorded on the balance sheet at historical cost and expensed when they are retired. Compliance payments are expensed when incurred. Allowances granted to or internally generated by TCPL are not attributed a value for accounting purposes. When required, TCPL accrues emission liabilities on the balance sheet upon the generation or sale of power using the best estimate of the amount required to settle the obligation. Allowances or credits not used for compliance are sold and recorded as revenue. In 2009, costs of compliance and revenues from the sale of allowances were not significant.

Northeastern U.S. states that are members of the Regional Greenhouse Gas Initiative (RGGI) implemented a CO_2 cap and trade program for electricity generators effective January 1, 2009. Under the RGGI, both the Ravenswood and OSP power generation facilities will be required to submit allowances by December 31, 2011. TCPL participated in the quarterly auctions of allowances for Ravenswood and OSP, and incurred related costs of $8 million in 2009. These costs were generally recovered through the power market and the net impact on TCPL was not significant.

Participants in the *Midwestern Greenhouse Gas Reduction Accord*, which involves six U.S. states and the province of Manitoba, are developing a regional strategy for reducing members' GHG emissions that will include a multi-sector cap and trade mechanism. Draft recommendations have been released but as yet not formally endorsed by participant states and Manitoba.

Climate change is a strategic issue for the U.S. government and federal policy to manage domestic GHG emissions continues to be a priority. The Environmental Protection Agency has released an endangerment finding regarding GHG emissions under the *Clean Air Act*. This finding was to determine whether the six types of GHGs in the atmosphere threaten the health and welfare of current and future generations. The U.S. House of Representatives passed a climate bill in June 2009 and the U.S. Senate is deliberating on a series of climate bills.

TCPL monitors climate change policy developments and, when warranted, participates in policy discussions. The Company is also continuing its programs to manage GHG emissions from its facilities and to evaluate new processes and technologies that result in improved efficiencies and lower GHG emission rates.

CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S. securities laws. The information is accumulated and communicated to management, including the President and Chief Executive Officer and the Chief Financial Officer, to allow timely decisions regarding required disclosure.

As at December 31, 2009, an evaluation of the effectiveness of TCPL's disclosure controls and procedures as defined under the rules adopted by the Canadian securities regulatory authorities and by the SEC was carried out under the supervision and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer. Based on this evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that the design and operation of TCPL's disclosure controls and procedures were effective as at December 31, 2009.

Management's Annual Report on Internal Control over Financial Reporting

Internal control over financial reporting is a process designed by or under the supervision of senior management and effected by the Board of Directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and preparation of consolidated financial statements for external purposes in accordance with Canadian GAAP, including a reconciliation to U.S. GAAP.

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting, no matter how well designed, has inherent limitations and can only provide reasonable assurance with respect to the preparation and fair presentation of published financial statements. Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on this evaluation, management concluded that internal control over financial reporting is effective as at December 31, 2009, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

In 2009, there was no change in TCPL's internal control over financial reporting that materially affected or is reasonably likely to materially affect TCPL's internal control over financial reporting.

CEO and CFO Certifications

TCPL's President and Chief Executive Officer and Chief Financial Officer have filed with the SEC and the Canadian securities regulators certifications regarding the quality of TCPL's public disclosures relating to its fiscal 2009 reports filed with the SEC and the Canadian securities regulators.

SIGNIFICANT ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

To prepare financial statements that conform with Canadian GAAP, TCPL is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses, since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgment in making these estimates and assumptions. The Company believes the following accounting policies and estimates require it to make assumptions about highly uncertain matters and changes in these estimates could have a material impact on the Company's financial information.

Regulated Accounting

The Company accounts for the impacts of rate regulation in accordance with GAAP. Three criteria must be met to use these accounting principles:

- The rates for regulated services or activities must be established by or 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 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 all three of these criteria have been met with respect to each of the regulated natural gas pipelines accounted for using regulated accounting principles. The most significant impact from the use of these accounting principles is that the timing of recognition of certain expenses and revenues in the regulated businesses may differ from that otherwise expected under GAAP in order to appropriately reflect the economic impact of the regulators' decisions regarding the Company's revenues and tolls.

Effective January 1, 2009, the Company's accounting for its future income taxes recorded on rate-regulated operations changed as discussed in the Accounting Changes section of this MD&A.

Financial Instruments and Hedges

Financial Instruments

The Company initially records all financial instruments on the balance sheet at their fair value. Subsequent measurement of the financial instruments is based on their classification. Financial assets are classified into the following categories: held for trading, available for sale, held-to-maturity investments and loans and receivables. Financial liabilities are classified as held for trading or other financial liabilities. The Company does not have any held-to-maturity investments.

Held-for-trading derivative financial assets and liabilities consist of swaps, options, forwards and futures. Commodity held-for-trading financial instruments are initially recorded at their fair value and changes to fair value are included in revenues. Changes in the fair value of interest rate and foreign exchange rate held-for-trading instruments are recorded in interest expense and in interest income and other, respectively.

The available-for-sale classification includes non-derivative financial assets that are designated as available for sale or are not included in the other three classifications. These instruments are accounted for initially at their fair value and changes to fair value are recorded through other comprehensive income. Trade receivables, loans and other receivables with fixed or determinable payments that are not quoted in an active market are classified as "loans and receivables" and are measured at amortized cost using the effective interest method, net of any impairment. Other financial liabilities consist of liabilities not classified as held for trading. Items in this financial instrument category are recognized at amortized cost using the effective interest method.

The recognition of gains and losses on the derivatives for the Canadian Mainline, Alberta System and Foothills exposures is determined through the regulatory process. The gains and losses on derivatives accounted for as part of rate-regulated accounting are deferred in Regulatory Assets or Regulatory Liabilities.

Hedges

The Company applies hedge accounting to its arrangements that qualify for hedge accounting treatment, which include fair value and cash flow hedges, and hedges of foreign currency exposures of net investments in self-sustaining foreign operations. Hedge accounting is discontinued prospectively when the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk. The changes in fair value are recognized in net income. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item, which are also recorded in net income.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income, while any ineffective portion is recognized in net income in the same financial category as the underlying transaction. When hedge accounting is discontinued, the amounts recognized previously in accumulated other comprehensive income are reclassified to net income during the periods when the variability in cash flows of the hedged item affects net income. Gains and losses on derivatives are reclassified immediately to net income from accumulated other comprehensive income when the hedged item is sold or terminated early, or when a hedged anticipated transaction is no longer expected to occur.

The Company also enters into cash flow hedges and fair value hedges for activities subject to rate regulation. Any gains and losses arising from the changes in the fair value of these hedges can be recovered through the tolls charged by the Company. As a result, any gains and losses are deferred as rate-regulated assets or liabilities on behalf of the ratepayers. When the hedges are settled, the realized gains or losses are collected from or refunded to the ratepayers in subsequent years.

In hedging the foreign currency exposure of a net investment in a self-sustaining foreign operation, the effective portion of foreign exchange gains and losses on the hedging instruments is recognized in other comprehensive income and the ineffective portion is recognized in net income. The amounts recognized previously in accumulated other comprehensive income are reclassified to net income in the event the Company settles or otherwise reduces its investment in a foreign operation.

The fair value of financial instruments and hedges, where fair value does not approximate carrying value, is primarily derived from market values adjusted for credit risk, which can fluctuate greatly from period to period. These changes in fair value can result in variability in net income as a result of recording these changes in fair value through earnings. The risks associated with fluctuations to earnings and cash flows for financial instruments and hedges are discussed further in the Risk Management and Financial Instruments section of this MD&A.

Depreciation and Amortization Expense

TCPL's plant, property and equipment are depreciated on a straight-line basis over their estimated useful lives once they are ready for their intended use. Pipeline and compression equipment are depreciated at annual rates ranging from one per cent to 25 per cent. Metering and other plant equipment are depreciated at various rates. Major power generation and natural gas storage plant, equipment and structures in the Energy business are depreciated on a straight-line basis over estimated service lives at average annual rates ranging from two per cent to ten per cent. Nuclear power generation 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 and the remaining lease term. Other Energy equipment is depreciated at various rates. Corporate plant, property and equipment are depreciated on a straight-line basis over estimated useful lives at average annual rates ranging from three per cent to 20 per cent.

Depreciation expense in 2009 was $1,319 million (2008 $1,189 million; 2007 $1,179 million) and is recorded in Pipelines and Energy. In Pipelines, depreciation rates are approved by regulators when applicable and depreciation expense is recoverable based on the cost of providing the services or products. If regulators permit recovery of depreciation through rates charged to customers, a change in the estimate of the useful lives of plant, property and equipment in the Pipelines segment will have no material impact on TCPL's net income but will directly affect funds generated from operations.

PPA amortization expense of $58 million was recorded in Energy each year from 2007 through 2009. The initial payment for a PPA is deferred and amortized on a straight-line basis over the term of the contract, with remaining terms ranging from eight years to 11 years.

Impairment of Long-Lived Assets and Goodwill

The Company reviews long-lived assets such as property, plant and equipment, and intangible assets for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows is less than the carrying value of the assets, an impairment loss is recognized for the excess of the carrying value over the fair value of the assets.

Goodwill is tested in the Pipelines and Energy segments for impairment annually, or more frequently if events or changes in circumstances indicate that the asset might be impaired. An initial assessment is made by comparing the fair value of the operations, which includes goodwill, to the book values of each reporting unit. If this fair value is less than book value, an impairment is indicated and a second test is performed to measure the amount of the impairment. In the second test, the implied fair value of the goodwill is calculated by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of the goodwill exceeds the calculated implied fair value of the goodwill, an impairment charge is recorded.

These valuations are based on management's projections of future cash flows and, therefore, require estimates and assumptions with respect to:

- Discount rates;
- commodity prices;
- market supply and demand assumptions;
- growth opportunities;
- output levels;
- competition from other companies; and
- regulatory changes.

Significant changes in these assumptions could affect the Company's need to record an impairment charge.

ACCOUNTING CHANGES

CHANGES IN ACCOUNTING POLICIES FOR 2009

Rate-Regulated Operations

Effective January 1, 2009, the temporary exemption was withdrawn from the CICA Handbook Section 1100 "Generally Accepted Accounting Principles", which permitted the recognition and measurement of assets and liabilities arising from rate regulation. In addition, Section 3465 "Income Taxes" was amended to require the recognition of future income tax assets and liabilities for rate-regulated operations. In accordance with the CICA Handbook accounting hierarchy, the Company chose to adopt accounting policies consistent with the U.S. Financial Accounting Standards Board's (FASB) Accounting Standards Codification (ASC) Topic 980 "Regulated Operations". As a result, TCPL retained its current method of accounting for its rate-regulated operations, except that the Company is required to recognize future income tax assets and liabilities, instead of using the taxes payable method, and records an offsetting adjustment to regulatory assets and liabilities. As a result of adopting this accounting change, additional future income tax liabilities and a regulatory asset in the amount of $1.4 billion were recorded January 1, 2009 in each of future income taxes and regulatory assets, respectively.

Adjustments to the 2009 financial statements have been made in accordance with the transitional provisions for Section 3465, which required a cumulative adjustment in the current period to future income taxes and regulatory assets. Restatement of prior periods' financial statements was not permitted under Section 3465.

Goodwill and Intangible Assets

Effective January 1, 2009, the Company adopted CICA Handbook Section 3064 "Goodwill and Intangible Assets", which replaced Section 3062 "Goodwill and Other Intangible Assets". Section 3064 gives guidance on the recognition of intangible assets and on the recognition and measurement of internally developed intangible assets. In addition, Section 3450 "Research and Development Costs" was withdrawn from the CICA Handbook. Adopting this accounting change did not have a material effect on the Company's financial statements.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities

Effective January 1, 2009, the Company adopted the accounting provisions of Emerging Issues Committee (EIC) Abstract EIC 173 "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". Under EIC 173, an entity's own credit risk and the credit risk of its counterparties are taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments. Adopting this accounting change did not have a material effect on the Company's financial statements.

FUTURE ACCOUNTING CHANGES

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests

CICA Handbook Section 1582 "Business Combinations" is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting the standard is expected to have a material effect on the way the Company accounts for future business combinations. Entities adopting Section 1582 will also be required to adopt CICA Handbook Sections 1601 "Consolidated Financial Statements" and 1602 "Non-Controlling Interests". These standards will require non-controlling interests to be presented as part of shareholders' equity on the balance sheet. In addition, the income statement of the controlling parent will include 100 per cent of the subsidiary's results and present the allocation between the controlling and non-controlling interests. These standards will be effective January 1, 2011, with early adoption permitted. The changes resulting from adopting Section 1582 will be applied prospectively and the changes from adopting Sections 1601 and 1602 will be applied retrospectively.

International Financial Reporting Standards

The CICA's Accounting Standards Board announced that Canadian publicly accountable enterprises are required to adopt IFRS, as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. Effective January 1, 2011, the Company will begin reporting under IFRS.

TCPL's conversion plan includes obtaining skilled people, providing education and training, analyzing the impact on TCPL of key differences between GAAP and IFRS, and developing and executing a phased approach to conversion and implementation. The current status of key elements of TCPL's conversion project is as follows:

Resources and Training

TCPL has established an IFRS project team to support the conversion effort. The team conducts technical research and provides issue identification, training, work group leadership, policy recommendations and implementation support. The project team is led by a multi-disciplinary Steering Committee that provides directional leadership for the conversion project and assists in developing accounting policy recommendations. Management also updates the Audit Committee on the progress of the IFRS project at each Audit Committee meeting.

TCPL's IFRS training, which began in 2008, includes project awareness sessions, an annual comprehensive IFRS immersion course, topic specific courses and systems training sessions. Throughout the project, IFRS training is being provided on an ongoing basis to TCPL staff and directors affected by the conversion to ensure they are knowledgeable about new IFRS developments.

Analysis of Differences Between IFRS and GAAP

TCPL's conversion project is being executed using a risk-based methodology focusing on the significant differences between GAAP and IFRS. A high-level diagnostic was completed in 2008 outlining the significant differences and rating each difference based on its expected level of significance to TCPL. In making this assessment, the technical accounting complexity, number of policy choices, estimated need for conversion resources and impact on systems were considered. The project team continues to assess the differences between GAAP and IFRS and their significance to the Company.

The differences between GAAP and IFRS that have been identified as significant to the Company are explained below. Several of the IFRS standards that are expected to be applicable to TCPL are in the process of being amended by the IASB. Amendments to existing standards are expected to continue until the January 1, 2011 effective date. TCPL actively monitors the IASB's schedule of projects, giving consideration to any proposed changes, where applicable, in its assessment of differences between IFRS and GAAP. As a result of proposed changes to certain IFRS, together with the current stage of the Company's IFRS project, TCPL cannot reasonably quantify the full impact that adopting IFRS will have on its financial position and future results.

Rate-Regulated Activities

Under GAAP, TCPL currently follows specific accounting policies unique to a rate-regulated business. In July 2009, the IASB issued an Exposure Draft "Rate-Regulated Activities". Under the Exposure Draft, regulatory assets and regulatory liabilities will represent the expected present values of future revenues that are expected to be recovered from or refunded to customers. Under GAAP, the Company measures these regulatory assets and regulatory liabilities on a historical cost basis in respect of future revenues that are expected to be recovered from or refunded to customers. The Exposure Draft also outlines certain criteria an entity must meet to be within the scope of the new standard. The Company continues to assess the impact of developments regarding this exposure draft, as they could have a significant effect on TCPL's balance sheet and could result in increased income volatility.

Plant, Property and Equipment

Under GAAP, items of plant, property and equipment are depreciated on a straight-line basis over their estimated service lives. Under IFRS, significant components of the same items of plant, property and equipment will be separately identified and depreciated over their respective estimated service life.

Joint Ventures

Under GAAP, TCPL proportionately consolidates its share of the accounts of joint ventures in which the Company is able to exercise joint control and uses the equity method of accounting for investments over which the Company is able to exercise significant influence.

The IASB issued an Exposure Draft, which is expected to be effective in 2011, under which TCPL would use the equity method of accounting for joint ventures in which the Company is able to exercise joint control or significant influence, but not sole control. For joint operations in which the Company is able to exercise joint control, TCPL would record its proportionate share of the assets, liabilities and related revenues and expenses, as well as expenses or liabilities the Company would incur directly on behalf of the assets.

Provisions

Under GAAP, the scope and timing of asset retirements related to regulated natural gas pipelines and hydroelectric power plants is uncertain. As a result, the Company has not recorded an amount for asset retirement obligations related to these assets with the exception of certain abandoned facilities.

Under IFRS, TCPL would be required to record obligations relating to the retirement of its regulated pipelines where a legal, contractual or constructive obligation currently exists. The Company is assessing its ability to reliably estimate the cost to abandon these assets in the future, where applicable.

Employee Benefits

Under GAAP, past service costs relating to the Company's defined benefit pension plans are recognized over the expected average remaining service life of the employees. Under IFRS, past service costs would be recognized on a straight-line basis over the average remaining vesting period.

Under GAAP, actuarial gains and losses are deferred and amortized using a "corridor" approach. Under IFRS, there are three alternatives for recognizing actuarial gains and losses. These gains or losses can be deferred and amortized subject to certain provisions that differ slightly from GAAP, recognized in profit and loss in the period they are incurred or recognized in other comprehensive income in the period they are incurred. The Company is currently assessing the IFRS alternatives.

Leases

Under GAAP and IFRS, leases that transfer to the Company substantially all the risks and rewards incidental to ownership of the leased item are capitalized at the commencement of the lease term. GAAP prescribes specific thresholds for evaluating whether substantially all the risks and rewards incidental to ownership of the leased item are transferred, while IFRS does not contain such specific thresholds. The Company is currently assessing its lease contracts, including contingent lease payments, under IFRS.

Financial Instruments

Under GAAP, contracts that meet specific scope exemptions or do not meet the definition of a derivative as they do not have a specified notional amount, are not subject to the recognition and measurement criteria for financial instruments. The Company is currently assessing these contracts to determine whether they are subject to IFRS recognition and measurement criteria for financial instruments.

Impairment of Non-Current Assets

The Company reviews non-current assets, such as plant, property and equipment and intangible assets with a definite, useful life, for indicators of impairment at each reporting date. Tests for impairment are performed if there is an indication that the carrying value of the assets may not be recoverable.

The method of determining a potential impairment loss is slightly different under GAAP than under IFRS and the Company is assessing the impact of the difference on TCPL.

Impairment of Goodwill

Under GAAP, an initial impairment assessment of goodwill is made by comparing the fair value of the operations, which includes goodwill, to the book values of each reporting unit. If the fair value is less than the book value, an impairment is indicated and a second test is performed to measure the amount of the impairment. In the second test, the implied fair value of the goodwill is calculated by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of the goodwill exceeds the calculated implied fair value of the goodwill, an impairment charge is recorded. Under IFRS, for the purposes of impairment testing, goodwill acquired in a business combination is allocated to cash-generating units that are expected to benefit from the synergies of the combination. An impairment loss is recognized when the recoverable amount of the cash-generating unit is less than the carrying amount, including goodwill.

Conversion Implementation

During the conversion implementation phase, TCPL will continue to execute required changes to its information systems and business processes, disclosure controls and internal controls over financial reporting. Required changes continue to be identified on a concurrent basis with the Company's analysis of significant GAAP differences. TCPL is also assessing the impact of transitioning to IFRS on its financial statement presentation and disclosures. The Company is monitoring and updating the effect of IFRS on its internal controls over financial reporting and does not expect any significant obstacles.

Information systems, including information technology systems and computer software, are being changed to accommodate IFRS. TCPL's accounting system has been expanded to enable the production of multiple financial statements based on reporting under both GAAP and IFRS, facilitating the requirement in 2010 to report GAAP financial information while tracking IFRS financial information. Other information system changes include allowing for the capture of new data, creation and deletion of accounts, modifications to existing systems relating to calculations, consolidations, models and reports, and other revisions to accounting software to accommodate IFRS accounting and reporting requirements.

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA[1]

(unaudited) *(millions of dollars except per share amounts)*	**2009** Fourth	Third	Second	First
Revenues	**2,206**	**2,253**	**2,127**	**2,380**
Net Income	**384**	**343**	**316**	**336**
Share Statistics				
Net income per share basic and diluted	**$0.58**	**$0.55**	**$0.52**	**$0.55**

(unaudited) *(millions of dollars except per share amounts)*	2008 Fourth	Third	Second	First
Revenues	2,332	2,137	2,017	2,133
Net Income	274	383	318	445
Share Statistics				
Net income per share basic and diluted	$0.47	$0.70	$0.60	$0.84

(1) The selected quarterly consolidated financial data has been prepared in accordance with GAAP.

Factors Impacting Quarterly Financial Information

In Pipelines, which consists primarily of the Company's investments in regulated pipelines and regulated natural gas storage facilities, annual revenues and net income fluctuate over the long term based on regulators' decisions and negotiated settlements with shippers. Generally, quarter-over-quarter revenues and net income during any particular fiscal year remain relatively stable with fluctuations resulting from adjustments being recorded due to regulatory decisions and negotiated settlements with shippers, seasonal fluctuations in short-term throughput volumes on U.S. pipelines, acquisitions and divestitures, and developments outside of the normal course of operations.

In Energy, which consists primarily of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities, quarter-over-quarter revenues and net income are affected by seasonal weather conditions, customer demand, market prices, capacity payments, planned and unplanned plant outages, acquisitions and divestitures, certain fair value adjustments and developments outside of the normal course of operations.

Significant developments that impacted EBIT and net income in 2009 and 2008 were as follows:

Fourth quarter 2009 Pipelines EBIT included a dilution gain of $29 million pre-tax ($18 million after tax) resulting from TCPL's reduced ownership interest in PipeLines LP after PipeLines LP issued common units to the public. Energy's EBIT included net unrealized gains of $7 million pre-tax ($5 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Net income included $30 million of favourable income tax adjustments resulting from reductions in the Province of Ontario's corporate income tax rates.

Third quarter 2009 Energy's EBIT included net unrealized gains of $14 million pre-tax ($10 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

Second quarter 2009 Energy's EBIT included net unrealized losses of $7 million pre-tax ($5 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Energy's EBIT also included contributions from Portlands Energy, which was placed in service in April 2009, and the negative impact of Western Power's lower overall realized power prices.

First quarter 2009 Energy's EBIT included net unrealized losses of $13 million pre-tax ($9 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

Fourth quarter 2008 Energy's EBIT included net unrealized gains of $7 million pre-tax ($6 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Corporate's EBIT included net unrealized losses of $57 million pre-tax ($39 million after tax) for changes in the fair value of derivatives that were used to manage the Company's exposure to rising interest rates but did not qualify as hedges for accounting purposes.

Third quarter 2008 Energy's EBIT included contributions from the August 2008 acquisition of Ravenswood. Net Income included favourable income tax adjustments of $26 million from an internal restructuring and realization of losses.

Second quarter 2008 Energy's EBIT included net unrealized gains of $12 million pre-tax ($8 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. In addition, Western Power's revenues and EBIT increased due to higher overall realized prices and market heat rates in Alberta.

First quarter 2008 Pipelines' EBIT included $279 million pre-tax ($152 million after tax) received by GTN and Portland from the Calpine bankruptcy settlements, and proceeds of $17 million pre-tax ($10 million after tax) from a lawsuit settlement. Energy's EBIT included a writedown of $41 million pre-tax ($27 million after tax) of costs related to the Broadwater LNG project and net unrealized losses of $17 million pre-tax ($12 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

FOURTH QUARTER 2009 HIGHLIGHTS

Reconciliation of Comparable Earnings, Comparable EBITDA, Comparable EBIT and EBIT to Net Income Applicable to Common Shares

	Pipelines		**Energy**		**Corporate**		**Total**	
Three months ended December 31 *(unaudited)* *(millions of dollars except per share amounts)*	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008
Comparable EBITDA[1]	**745**	780	**248**	297	**(28)**	(33)	**965**	1,044
Depreciation and amortization	**(257)**	(224)	**(86)**	(80)			**(343)**	(304)
Comparable EBIT[1]	**488**	556	**162**	217	**(28)**	(33)	**622**	740
Specific items:								
Dilution gain from reduced interest in PipeLines LP	**29**						**29**	
Fair value adjustment of natural gas inventory in storage and forward contracts			**7**	7			**7**	7
EBIT[1]	**517**	556	**169**	224	**(28)**	(33)	**658**	747
Interest expense							**(193)**	(330)
Interest expense of joint ventures							**(17)**	(21)
Interest income and other							**22**	(5)
Income taxes							**(66)**	(93)
Non-controlling interests							**(20)**	(19)
Net Income							**384**	279
Preferred share dividends							**(5)**	(5)
Net Income Applicable to Common Shares							**379**	274
Specific items (net of tax, where applicable):								
Dilution gain from reduced interest in PipeLines LP							**(18)**	
Fair value adjustment of natural gas inventory in storage and forward contracts							**(5)**	(6)
Income tax adjustments							**(30)**	
Comparable Earnings[1]							**326**	268

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of comparable EBITDA, comparable EBIT, EBIT, and comparable earnings.

TCPL's net income was $384 million and net income applicable to common shares was $379 million in fourth quarter 2009 compared to $279 million and $274 million, respectively, in fourth quarter 2008. The $105 million increase in net income applicable to common shares reflected:

Decreased EBIT from Pipelines primarily due to the negative impact of a weaker U.S. dollar on Pipeline's U.S. operations and increased business development costs related to the Alaska pipeline project. These decreases were partially offset by an $18 million after tax ($29 million pre-tax) dilution gain resulting from TCPL's reduced ownership interest in PipeLines LP following PipeLines LP's public issuance of common units.

decreased EBIT from Energy primarily due to lower power prices in Western Power and U.S. Power, and the impact of a weaker U.S. dollar on Energy's U.S. operations, partially offset by higher contribution from the Natural Gas Storage business due to increased third party storage revenues and increased earnings as a result of the start up of Portlands Energy.

decreased interest expense primarily due to increased capitalized interest, reduced losses from changes in the fair value of interest rate derivatives used to manage TCPL's exposure to fluctuating interest rates and the positive impact of a weaker U.S. dollar. These decreases were partially offset by incremental interest expense for new debt issuances in 2009.

increased interest income and other due to the positive impact of a weaker U.S. dollar on working capital balances and changes in the fair value of derivatives used to manage the Company's exposure to foreign exchange rate fluctuations; and

decreased income tax expense primarily due to positive income tax adjustments in fourth quarter 2009, including $30 million resulting from a reduction in the Province of Ontario's corporate income tax rates, partially offset by higher pre-tax income.

Comparable earnings in fourth quarter 2009 increased $58 million to $326 million, compared to $268 million for the same period in 2008. Comparable earnings in fourth quarter 2009 excluded the $18 million after tax dilution gain resulting from TCPL's reduced ownership in PipeLines LP and the $30 million of favourable income tax adjustments. Comparable earnings in fourth quarter 2009 and 2008 also excluded net unrealized after tax gains of $5 million ($7 million pre-tax) and $6 million ($7 million pre-tax), respectively, resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

Pipelines comparable EBIT was $488 million in fourth quarter 2009 compared to $556 million for the same period in 2008. Comparable EBIT excluded the $29 million pre-tax dilution gain resulting from a reduction in TCPL's ownership interest in PipeLines LP following PipeLines LP's public issuance of common units in fourth quarter 2009.

Canadian Mainline's net income for fourth quarter 2009 decreased $2 million to $72 million from $74 million for the same period in 2008. Net income for fourth quarter 2009 reflected a lower average investment base and a lower ROE set by the NEB at 8.57 per cent in 2009 compared to 8.71 per cent in 2008, partially offset by higher OM&A cost savings.

Canadian Mainline's EBITDA for fourth quarter 2009 of $282 million decreased $18 million compared to the same period in 2008 primarily due to lower revenues as a result of a recovery of lower income taxes and a lower overall return on average investment base in the 2009 tolls, partially offset by higher OM&A cost savings.

The Alberta System's net income was $45 million in fourth quarter 2009 compared to $48 million for the same period in 2008. Earnings in 2009 and 2008 reflected the impact of the 2008-2009 Revenue Requirement Settlement approved by the AUC in December 2008 and by the NEB in December 2009.

The Alberta System's EBITDA was $193 million in fourth quarter 2009 compared to $152 million for the same period in 2008. The increase reflected higher revenues as a result of the recovery of higher depreciation and income taxes, partially offset by lower settlement earnings.

EBITDA from Other Canadian Pipelines was $15 million in fourth quarter 2009 compared to $11 million for the same period in 2008. The increase was primarily due to an adjustment to TQM's cost of capital for 2009.

ANR's EBITDA in fourth quarter 2009 was $84 million compared to $99 million for the same period in 2008. The decrease in EBITDA was primarily due to the negative impact of a weaker U.S. dollar.

GTN's EBITDA in fourth quarter 2009 decreased $9 million from the same period in 2008 primarily due to the negative impact of a weaker U.S. dollar and the sale of North Baja to PipeLines LP.

EBITDA for the remainder of the U.S. Pipelines was $132 million in fourth quarter 2009 compared to $144 million for the same period in 2008. The decrease was primarily due to the negative impact of a weaker U.S. dollar on U.S. Pipelines operations, partially offset by the acquisition of North Baja by PipeLines LP.

Pipelines business development comparable EBITDA losses increased $27 million in fourth quarter 2009 compared to the same period in 2008 primarily due to increased business development costs related to the Alaska pipeline project.

Energy's comparable EBIT was $162 million in fourth quarter 2009 compared to $217 million in fourth quarter 2008. Comparable EBIT in fourth quarter 2009 and fourth quarter 2008 excluded net unrealized gains of $7 million in each period resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

Western Power's EBITDA of $61 million and power revenues of $203 million in fourth quarter 2009 decreased $67 million and $95 million, respectively, compared to the same period in 2008. These decreases were primarily due to lower earnings from the Alberta power portfolio resulting from lower overall realized power prices on lower volumes of power sold. The reduction in power prices and sales volumes reflected reduced demand for electricity in Alberta as a result of the North American economic slowdown. Average spot market power prices in Alberta decreased 51 per cent or $49 per MWh in fourth quarter 2009 compared to fourth quarter 2008.

Eastern Power's EBITDA of $56 million in fourth quarter 2009 increased $13 million compared to the same period in 2008. These increases were primarily due to incremental earnings from Portlands Energy which went into service in April 2009.

TCPL's proportionate share of Bruce Power's comparable EBITDA of $70 million in fourth quarter 2009 was consistent with fourth quarter 2008. Increased revenues from higher realized prices and an annual lease expense reduction at Bruce B were offset by higher non-lease operating expenses and lower volumes caused by an increase in outage days.

TCPL's proportionate share of Bruce A's comparable EBITDA decreased $28 million to a loss of $29 million in fourth quarter 2009 compared to a loss of $1 million in fourth quarter 2008. The higher loss was due to decreased volumes and higher operating costs as a result of an unplanned extension of the two planned outages which were rescheduled to September 2009 from March 2009. Bruce A's plant availability in fourth quarter 2009 was 47 per cent as a result of 84 outage days compared to an availability of 62 per cent and 63 outage days in the same period in 2008.

TCPL's proportionate share of Bruce B's comparable EBITDA increased $28 million to $99 million in fourth quarter 2009 compared to fourth quarter 2008 primarily due to higher realized prices resulting from the recognition of payments received pursuant to the floor price mechanism in Bruce B's contract with the OPA, as well as a reduction in annual lease expense. Provisions in the Bruce B lease agreement with Ontario Power Generation allow for a reduction in annual lease expense if the annual Ontario spot price for electricity was less than $30 per MWh.

U.S. Power's comparable EBITDA for fourth quarter 2009 of $29 million decreased $21 million compared to the same period in 2008. The decrease was primarily due to lower overall realized power prices and the impact of a weaker U.S. dollar, partially offset by incremental revenue realized on contract sales in New England. While average spot market power prices in New England decreased in fourth quarter 2009 compared to fourth quarter 2008, the majority of U.S. Power's sales volumes were sold at contracted prices.

Natural Gas Storage's comparable EBITDA in fourth quarter 2009 was $49 million compared to $34 million for the same period in 2008. The $15 million increase was primarily due to increased third party storage revenues as a result of higher realized seasonal natural gas price spreads. Comparable EBITDA excluded net unrealized gains of $7 million in fourth quarter 2009 (2008 gains of $7 million), resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

Corporate EBIT losses in fourth quarter 2009 were $28 million compared to losses of $33 million for the same period in 2008. The decreases in EBIT losses were primarily due to lower support service costs in fourth quarter 2009.

Interest expense in fourth quarter 2009 decreased $137 million to $193 million from $330 million in fourth quarter 2008. The decrease reflected increased capitalized interest to finance the Company's larger capital growth program in 2009, primarily due to Keystone construction, and a decrease in U.S. dollar-denominated interest expense due to the impact of a weaker U.S. dollar in fourth quarter 2009 compared to fourth quarter 2008. Interest expense also decreased due to reduced losses in fourth quarter 2009 compared to 2008 from changes in the fair value of derivatives used to manage the Company's exposure to interest rate fluctuations. These decreases were partially offset by incremental interest expense on new debt issues of US$2.0 billion in January 2009 and $700 million in February 2009.

Interest Income and Other in fourth quarter 2009 was income of $22 million compared to an expense of $5 million for the same period in 2008. The increase in income of $27 million in fourth quarter 2009 was primarily due to the positive impact of a weaker U.S. dollar on working capital balances in fourth quarter 2009 and higher gains from changes in the fair value of derivatives used to manage the Company's exposure to foreign exchange rate fluctuations. These increases were partially offset by lower interest income due to lower interest rates.

Income Taxes were $66 million in fourth quarter 2009 compared to $93 million for the same period in 2008. The decrease was primarily due to positive income tax adjustments in 2009, including a $30 million favourable adjustment resulting from a reduction in the Province of Ontario's corporate income tax rates, partially offset by higher pre-tax income.

SHARE INFORMATION

At February 22, 2010, TCPL had 649 million issued and outstanding common shares, and there were no outstanding options to purchase common shares.

OTHER INFORMATION

Additional information relating to TCPL, including the Company's Annual Information Form and other continuous disclosure documents, is available on SEDAR at www.sedar.com under TransCanada PipeLines Limited.

Other selected consolidated financial information for 2000 to 2009 is found under the heading "Ten Year Financial Highlights" in the Supplementary Information section of the Company's Annual Report.

GLOSSARY OF TERMS

AGIA	Alaska Gasline Inducement Act
Alaska Pipeline Project	A proposed natural gas pipeline extending from Prudhoe Bay, Alaska to either Alberta or Valdez, Alaska
Alberta System	A natural gas transmission system in Alberta
American Natural Resources (ANR)	A natural gas transmission system extending from producing fields located primarily in Texas, Oklahoma, the Gulf of Mexico and Louisiana to markets located primarily in Wisconsin, Michigan, Illinois, Ohio and Indiana, and regulated underground natural gas storage facilities in Michigan
ANR Pipeline	ANR Pipeline Company
APG	Aboriginal Pipeline Group
ATWACC	After-tax weighted average cost of capital
AUC	Alberta Utilities Commission
B.C.	British Columbia
Bbl/d	Barrel(s) per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
Bear Creek	A natural gas-fired cogeneration plant near Grande Prairie, Alberta
Bécancour	A natural gas-fired cogeneration plant near Trois-Rivières, Québec
Bison	A pipeline under construction extending from the Powder River Basin in Wyoming to Northern Border in North Dakota
BPC	BPC Generation Infrastructure Trust
Broadwater	A proposed offshore LNG project in Long Island Sound, New York
Bruce A	A partnership interest in the nuclear power generation facilities of Bruce Power A L.P.
Bruce B	A partnership interest in the nuclear power generation facilities of Bruce Power L.P.
Bruce Power	Bruce A and Bruce B, collectively
Calpine	Calpine Corporation
Canadian Mainline	A natural gas transmission system extending from the Alberta/Saskatchewan border east into Québec
Cancarb	A waste-heat fuelled power plant at the Cancarb thermal carbon black facility in Medicine Hat, Alberta
Carseland	A natural gas-fired cogeneration plant located near Carseland, Alberta
Cartier Wind	Five wind farms in Gaspé, Québec, three of which are operational and two are under construction
Chinook	A proposed power transmission line project that will originate in Montana and terminate in Nevada
CICA	Canadian Institute of Chartered Accountants
CNSC	Canadian Nuclear Safety Commission
CO_2	Carbon dioxide
Coolidge	A simple-cycle, natural gas-fired peaking power generation station under construction in Coolidge, Arizona
CrossAlta	An underground natural gas storage facility near Crossfield, Alberta
DB Plans	Defined benefit plans
DRP	Dividend Reinvestment and Share Purchase Plan
EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes, depreciation and amortization
Edson	A natural gas storage facility near Edson, Alberta
EIC	Emerging Issues Committee
FASB	Financial Accounting Standards Board
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission (U.S.)
Foothills	A natural gas transmission system extending from central Alberta to the B.C./U.S. border and to the Saskatchewan/U.S. border
GAAP	Generally accepted accounting principles
Gas Pacifico	A natural gas transmission system extending from Loma de la Lata, Argentina to Concepción, Chile
GHG	Greenhouse gas
Grandview	A natural gas-fired cogeneration plant near Saint John, New Brunswick
Great Lakes	A natural gas transmission system that connects to the Canadian Mainline and serves markets in Eastern Canada and the northeastern and midwestern U.S.
Gas Transmission Northwest (GTN)	A natural gas transmission system extending from the B.C./Idaho border to the Oregon/California border, traversing Idaho, Washington and Oregon
GTNC	Gas Transmission Northwest Company
Guadalajara	A natural gas pipeline under construction in Mexico extending from Manzanillo, Colima to Guadalajara, Jalisco

GWh	Gigawatt hours
Halton Hills	A natural gas-fired, combined-cycle power plant under construction near Toronto, Ontario
HS&E	Health, Safety and Environment
IASB	International Accounting Standards Board
IESO	Independent Electricity System Operator
IFRS	International Financial Reporting Standards
INNERGY	An industrial natural gas marketing company based in Concepción, Chile
Iroquois	A natural gas transmission system that connects with the Canadian Mainline near Waddington, New York, and delivers natural gas to the northeastern U.S.
Irving	Irving Oil Limited
ISO	International Organization for Standardization
Keystone	A pipeline under construction that will transport crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, and to Cushing, Oklahoma
Kibby Wind	A wind power project located in Kibby and Skinner Townships in northwestern Franklin County, Maine
km	Kilometre(s)
LIBOR	London Interbank Offered Rate
LNG	Liquefied natural gas
MacKay River	A natural gas-fired cogeneration plant located near Fort McMurray, Alberta
MD&A	Management's Discussion and Analysis
Mackenzie Gas Pipeline (MGP) Project	A proposed natural gas pipeline extending from a point near Inuvik, Northwest Territories to the northern border of Alberta
mmcf/d	Million cubic feet per day
Moody's	Moody's Investors Service
MOP	Maximum operating pressure
MW	Megawatt(s)
MWh	Megawatt hours
NEB	National Energy Board of Canada
NGTL	NOVA Gas Transmission Ltd.
North Baja	A natural gas transmission system extending from Arizona to the Baja California, Mexico/California border
Northern Border	A natural gas transmission system extending from a point near Monchy, Saskatchewan, to the U.S. Midwest
NYISO	New York Independent System Operator
Oakville	A proposed natural gas-fired, combined-cycle power plant in Oakville, Ontario
OM&A	Operating, maintenance and administration
OMERS	Ontario Municipal Employees Retirement System
OPA	Ontario Power Authority
Ocean State Power (OSP)	A natural gas-fired, combined-cycle plant in Burrillville, Rhode Island
Palomar	A proposed pipeline extending from GTN to the Columbia River northwest of Portland
PipeLines LP	TC PipeLines, LP
Portland	A natural gas transmission system extending from a point near East Hereford, Québec to the northeastern U.S.
Portlands Energy	A natural gas-fired, combined-cycle power plant in Toronto, Ontario
PPA	Power purchase arrangement
PWU	Power Works' Union Trust
Ravenswood	A natural gas- and oil-fired generating facility consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology located in Queens, New York
Redwater	A natural gas-fired cogeneration plant located near Redwater, Alberta
RGGI	Regional Greenhouse Gas Initiative
ROE	Rate of return on common equity
S&P	Standard and Poor's
SEC	Securities and Exchange Commission (U.S.)
SEP	Society of Energy Professionals Trust
Sheerness	A coal-fired power generating facility located near Hanna, Alberta
Sundance A	A coal-fired power generating facility located near Wabamun, Alberta
Sundance B	A coal-fired power generating facility located near Wabamun, Alberta
Tamazunchale	A natural gas transmission system in Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi
TC Hydro	Hydroelectric generation assets located in New Hampshire, Vermont and Massachusetts
TCPL or the Company	TransCanada PipeLines Limited
TCPL USA	TransCanada PipeLine USA Ltd.
TCPM	TransCanada Power Marketing Ltd.

Trans Québec & Maritimes (TQM)	A natural gas transmission system that connects with the Canadian Mainline and transports natural gas in Québec, from Montreal to the Portland system and to Québec City
TQM Pipeline	Trans Québec & Maritimes Pipeline Inc.
TransCanada	TransCanada Corporation
TransGas	A natural gas transmission system extending from Mariquita in the central region of Colombia to Cali in the southwest region of Colombia
Tuscarora	A natural gas transmission system extending from Malin, Oregon to Wadsworth, Nevada
U.S.	United States
VaR	Value-at-Risk
Ventures LP	Natural gas transmission systems in Alberta that supply natural gas to the oilsands region of northern Alberta and to a petrochemical complex at Joffre, Alberta
WCI	Western Climate Initiative
WCSB	Western Canada Sedimentary Basin
Zephyr	A proposed power transmission line project originating in Wyoming and terminating in Nevada

Report of Management

The consolidated financial statements included in this Annual Report are the responsibility of the management of TransCanada PipeLines Limited's (TCPL or the Company) 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 judgements. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management's Discussion and Analysis in this Annual Report has been prepared by management based on the Company's financial results prepared in accordance with GAAP. It compares the Company's financial and operating performance in 2009 to that in 2008 and should be read in conjunction with the consolidated financial statements and accompanying notes. In addition, it highlights significant changes between 2008 and 2007.

Management has designed and maintains a system of internal controls over financial reporting, including a program of internal audits. Management believes these controls provide reasonable assurance that financial records are reliable and form a proper basis for the preparation of financial statements. The internal controls over financial reporting include management's communication to employees of policies that govern ethical business conduct.

Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal controls over financial reporting based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded, based on its evaluation, that internal controls over financial reporting are effective as of December 31, 2009 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

The Board of Directors has appointed an Audit Committee consisting of independent, non-management directors. The Audit Committee meets with management at least five times a year and meets independently with the internal and external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form. The Audit Committee's responsibilities include overseeing management's performance in carrying out its financial reporting responsibilities and reviewing 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 independent external auditors are able to access the Audit Committee without the requirement to obtain prior management approval.

The Audit Committee approves the terms of engagement of the independent external auditors and reviews the annual audit plan, the Auditors' Report and the results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The shareholders have appointed KPMG LLP as independent external auditors to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's consolidated financial position, results of operations and cash flows in accordance with GAAP. The report of KPMG LLP outlines the scope of its examination and its opinion on the consolidated financial statements.

Harold N. Kvisle President and Chief Executive Officer	**Gregory A. Lohnes** Executive Vice-President and Chief Financial Officer

February 22, 2010

To the Shareholders of TransCanada PipeLines Limited

Auditors' Report

We have audited the consolidated balance sheets of TransCanada PipeLines Limited as at December 31, 2009 and 2008 and the consolidated statements of income, comprehensive income, accumulated other comprehensive income, shareholders' equity and cash flows for each of the years in the three year period ended December 31, 2009. 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 and in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about 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, 2009 and 2008 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2009 in accordance with Canadian generally accepted accounting principles.

Chartered Accountants
Calgary, Canada

February 22, 2010

TRANSCANADA PIPELINES LIMITED
CONSOLIDATED INCOME

Year ended December 31 *(millions of dollars)*	**2009**	2008	2007
Revenues	**8,966**	8,619	8,828
Operating and Other Expenses/(Income)			
Plant operating costs and other	**3,367**	3,014	3,030
Commodity purchases resold	**1,511**	1,501	1,901
Other income	**(49)**	(38)	(48)
Calpine bankruptcy settlements (Note 18)		(279)	
Writedown of Broadwater LNG project costs (Note 7)		41	
	4,829	4,239	4,883
	4,137	4,380	3,945
Depreciation and amortization (Note 7)	**1,377**	1,247	1,237
	2,760	3,133	2,708
Financial Charges/(Income)			
Interest expense (Note 10)	**986**	962	961
Interest expense of joint ventures (Note 11)	**64**	72	75
Interest income and other	**(119)**	(42)	(118)
	931	992	918
Income before Income Taxes and Non-Controlling Interests	**1,829**	2,141	1,790
Income Taxes (Note 19)			
Current	**32**	524	429
Future	**344**	67	54
	376	591	483
Non-Controlling Interests (Note 15)	**74**	108	75
Net Income	**1,379**	1,442	1,232
Preferred Share Dividends (Note 17)	**22**	22	22
Net Income Applicable to Common Shares	**1,357**	1,420	1,210

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

TRANSCANADA PIPELINES LIMITED
CONSOLIDATED CASH FLOWS

Year ended December 31 *(millions of dollars)*	**2009**	2008	2007
Cash Generated from Operations			
Net income	**1,379**	1,442	1,232
Depreciation and amortization	**1,377**	1,247	1,237
Future income taxes (Note 19)	**344**	67	54
Non-controlling interests (Note 15)	**74**	108	75
Employee future benefits funding (in excess of)/lower than expense (Note 22)	**(111)**	17	43
Writedown of Broadwater LNG project costs (Note 7)		41	
Other	**(19)**	70	(38)
	3,044	2,992	2,603
(Increase)/decrease in operating working capital (Note 23)	**(88)**	128	63
Net cash provided by operations	**2,956**	3,120	2,666
Investing Activities			
Capital expenditures	**(5,417)**	(3,134)	(1,651)
Acquisitions, net of cash acquired (Note 9)	**(902)**	(3,229)	(4,223)
Disposition of assets, net of current income taxes (Note 9)		28	35
Deferred amounts and other	**(571)**	(459)	(169)
Net cash used in investing activities	**(6,890)**	(6,794)	(6,008)
Financing Activities			
Dividends on common and preferred shares (Notes 16 and 17)	**(998)**	(817)	(725)
Distributions paid to non-controlling interests	**(78)**	(119)	(66)
Advances from/(to) parent (Note 25)	**932**	(180)	389
Notes payable (repaid)/issued, net (Note 20)	**(244)**	1,659	(412)
Long-term debt issued, net of issue costs (Note 10)	**3,267**	2,197	2,616
Reduction of long-term debt	**(1,005)**	(840)	(1,088)
Long-term debt of joint ventures issued (Note 11)	**226**	173	142
Reduction of long-term debt of joint ventures	**(246)**	(120)	(157)
Common shares issued (Note 16)	**1,676**	2,419	1,842
Partnership units of subsidiary issued, net of issue costs (Note 9)	**193**		348
Junior subordinated notes issued, net of issue costs (Note 12)			1,094
Preferred securities redeemed			(488)
Net cash provided by financing activities	**3,723**	4,372	3,495
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(110)**	98	(50)
(Decrease)/Increase in Cash and Cash Equivalents	**(321)**	796	103
Cash and Cash Equivalents			
Beginning of year	**1,300**	504	401
Cash and Cash Equivalents			
End of year	**979**	1,300	504

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

TRANSCANADA PIPELINES LIMITED
CONSOLIDATED BALANCE SHEET

December 31 *(millions of dollars)*	**2009**	2008
ASSETS		
Current Assets		
Cash and cash equivalents	**979**	1,300
Accounts receivable	**968**	1,280
Due from TransCanada Corporation (Note 25)	**845**	1,329
Inventories	**511**	489
Other	**701**	523
	4,004	4,921
Plant, Property and Equipment (Note 5)	**32,879**	29,189
Goodwill (Note 6)	**3,763**	4,397
Regulatory Assets (Note 14)	**1,524**	201
Intangibles and Other Assets (Note 7)	**2,500**	2,027
	44,670	40,735
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable (Note 20)	**1,687**	1,702
Accounts payable	**2,191**	2,102
Accrued interest	**380**	361
Current portion of long-term debt (Note 10)	**478**	786
Current portion of long-term debt of joint ventures (Note 11)	**212**	207
	4,948	5,158
Due to TransCanada Corporation (Note 25)	**2,069**	1,621
Regulatory Liabilities (Note 14)	**385**	317
Deferred Amounts (Note 13)	**743**	1,168
Future Income Taxes (Note 19)	**2,893**	1,253
Long-Term Debt (Note 10)	**16,186**	15,368
Long-Term Debt of Joint Ventures (Note 11)	**753**	869
Junior Subordinated Notes (Note 12)	**1,036**	1,213
	29,013	26,967
Non-Controlling Interests (Note 15)	**785**	805
Shareholders' Equity	**14,872**	12,963
	44,670	40,735

Commitments, Contingencies and Guarantees (Note 24)
The accompanying notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board:

Harold N. Kvisle
Director

Kevin E. Benson
Director

TRANSCANADA PIPELINES LIMITED
CONSOLIDATED COMPREHENSIVE INCOME

Year ended December 31 *(millions of dollars)*	**2009**	2008	2007
Net Income	**1,379**	1,442	1,232
Other Comprehensive (Loss)/Income, Net of Income Taxes			
Change in foreign currency translation gains and losses on investments in foreign operations[(1)]	**(471)**	571	(350)
Change in gains and losses on hedges of investments in foreign operations[(2)]	**258**	(589)	79
Change in gains and losses on derivative instruments designated as cash flow hedges[(3)]	**77**	(60)	42
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[(4)]	**(24)**	(23)	42
Change in gains and losses on available-for-sale financial instruments[(5)]		2	
Other Comprehensive (Loss)/Income	**(160)**	(99)	(187)
Comprehensive Income	**1,219**	1,343	1,045

(1) Net of income tax expense of $92 million in 2009 (2008 $104 million recovery; 2007 $101 million expense).

(2) Net of income tax expense of $124 million in 2009 (2008 $303 million recovery; 2007 $41 million expense).

(3) Net of income tax expense of $7 million in 2009 (2008 $41 million recovery; 2007 $27 million expense).

(4) Net of income tax expense of $9 million in 2009 (2008 $19 million recovery; 2007 $23 million expense).

(5) Net of income tax expense of nil in 2008.

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

TRANSCANADA PIPELINES LIMITED
CONSOLIDATED ACCUMULATED OTHER COMPREHENSIVE INCOME

(millions of dollars)	Currency Translation Adjustments	Cash Flow Hedges and Other	Total
Balance at January 1, 2007	(90)		(90)
Transition adjustment resulting from adopting new financial instruments standards(1)		(96)	(96)
Change in foreign currency translation gains and losses on investments in foreign operations(2)	(350)		(350)
Change in gains and losses on hedges of investments in foreign operations(3)	79		79
Change in gains and losses on derivative instruments designated as cash flow hedges(4)		42	42
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods(5)		42	42
Balance at December 31, 2007	(361)	(12)	(373)
Change in foreign currency translation gains and losses on investments in foreign operations(2)	571		571
Change in gains and losses on hedges of investments in foreign operations(3)	(589)		(589)
Change in gains and losses on derivative instruments designated as cash flow hedges(4)		(60)	(60)
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods(5)		(23)	(23)
Change in gains and losses on available-for-sale financial instruments(6)		2	2
Balance at December 31, 2008	(379)	(93)	(472)
Change in foreign currency translation gains and losses on investments in foreign operations(2)	**(471)**		**(471)**
Change in gains and losses on hedges of investments in foreign operations(3)	**258**		**258**
Change in gains and losses on derivative instruments designated as cash flow hedges(4)		**77**	**77**
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods(5)(7)		**(24)**	**(24)**
Balance at December 31, 2009	**(592)**	**(40)**	**(632)**

(1) Net of income tax recovery of $44 million in 2007.

(2) Net of income tax expense of $92 million in 2009 (2008 $104 million recovery; 2007 $101 million expense).

(3) Net of income tax expense of $124 million in 2009 (2008 $303 million recovery; 2007 $41 million expense).

(4) Net of income tax expense of $7 million in 2009 (2008 $41 million recovery; 2007 $27 million expense).

(5) Net of income tax expense of $9 million in 2009 (2008 $19 million recovery; 2007 $23 million expense).

(6)

Net of income tax expense of nil in 2008.

(7) Gains related to cash flow hedges reported in Accumulated Other Comprehensive Income and expected to be reclassified to Net Income in 2010 are estimated to be $14 million ($12 million, net of tax). These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

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

TRANSCANADA PIPELINES LIMITED
CONSOLIDATED SHAREHOLDERS' EQUITY

Year ended December 31 *(millions of dollars)*	**2009**	2008	2007
Common Shares			
Balance at beginning of year	**8,973**	6,554	4,712
Proceeds from shares issued (Note 16)	**1,676**	2,419	1,842
Balance at end of year	**10,649**	8,973	6,554
Preferred Shares			
Balance at beginning and end of year	**389**	389	389
Contributed Surplus			
Balance at beginning of year	**284**	281	277
Increased ownership in PipeLines LP (Note 9)	**47**		
Other	**4**	3	4
Balance at end of year	**335**	284	281
Retained Earnings			
Balance at beginning of year	**3,789**	3,202	2,719
Net income	**1,379**	1,442	1,232
Common share dividends	**(1,015)**	(833)	(731)
Preferred share dividends (Note 17)	**(22)**	(22)	(22)
Transition adjustment resulting from adopting new financial instruments accounting standards			4
Balance at end of year	**4,131**	3,789	3,202
Accumulated Other Comprehensive Income			
Balance at beginning of year	**(472)**	(373)	(90)
Other comprehensive (loss)/income	**(160)**	(99)	(187)
Transition adjustment resulting from adopting new financial instruments accounting standards			(96)
Balance at end of year	**(632)**	(472)	(373)
	3,499	3,317	2,829
Total Shareholders' Equity	**14,872**	12,963	10,053

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

TRANSCANADA PIPELINES LIMITED
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 DESCRIPTION OF TRANSCANADA PIPELINES LIMITED'S BUSINESS

TransCanada PipeLines Limited (TCPL or the Company) is a wholly owned subsidiary of TransCanada Corporation (TransCanada) and is a leading North American energy company. TCPL operates in two business segments, Pipelines and Energy, each of which offers different products and services.

Pipelines

The Pipelines segment consists primarily of the Company's investments in regulated pipelines and regulated natural gas storage facilities. Through its Pipelines segment, TCPL owns and operates:

- a natural gas transmission system extending from the Alberta/Saskatchewan border east into Québec (Canadian Mainline);
- a natural gas transmission system in Alberta (Alberta System);
- a natural gas transmission system extending from producing fields located primarily in Texas, Oklahoma, the Gulf of Mexico and Louisiana to markets located primarily in Wisconsin, Michigan, Illinois, Ohio and Indiana, and to regulated natural gas storage facilities in Michigan (ANR);
- a natural gas transmission system extending from the British Columbia (B.C.)/Idaho border to the Oregon/California border (GTN);
- a natural gas transmission system extending from central Alberta to the B.C./Idaho border and to the Saskatchewan/Montana border (Foothills);
- natural gas transmission systems in Alberta that supply natural gas to the oil sands region of northern Alberta and to a petrochemical complex at Joffre, Alberta (Ventures LP); and
- a natural gas transmission system in Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi (Tamazunchale).

Through its Pipelines segment, TCPL operates and has ownership interests in pipeline systems as follows:

- a 53.6 per cent direct ownership interest in a natural gas transmission system that connects to the Canadian Mainline and serves markets in Eastern Canada and the northeastern and midwestern United States (U.S.) (Great Lakes);
- a 61.7 per cent interest in a natural gas transmission system that extends from a point near East Hereford, Québec to the northeastern U.S. (Portland);
- a 50 per cent interest in a natural gas transmission system that connects with the Canadian Mainline and transports natural gas in Québec, from Montreal to the Portland system and to Québec City (TQM); and
- a 38.2 per cent interest in TC PipeLines, LP (PipeLines LP), whose ownership interests in pipelines operated by TCPL are as follows:
  - a 46.4 per cent interest in Great Lakes, in which TCPL has a combined 71.3 per cent effective ownership interest through PipeLines LP and a direct interest described above;
  - a 50 per cent interest in a natural gas transmission system extending from a point near Monchy, Saskatchewan, to the U.S. Midwest (Northern Border), in which TCPL has a 19.1 per cent effective ownership interest through PipeLines LP;
  - a 100 per cent interest in a natural gas transmission system extending from Arizona to Baja California, at the Mexico/California border (North Baja), in which TCPL has a 38.2 per cent effective ownership interest through PipeLines LP; and
  - a 100 per cent interest in a natural gas transmission system extending from Malin, Oregon to Wadsworth, Nevada (Tuscarora), in which TCPL has a 38.2 per cent effective ownership interest through PipeLines LP.

TCPL does not operate but has ownership interests in pipelines and natural gas marketing activities as follows:

- a 44.5 per cent interest in a natural gas transmission system that connects with the Canadian Mainline near Waddington, New York, and delivers natural gas to customers in the northeastern U.S. (Iroquois);
- a 46.5 per cent interest in a natural gas transmission system extending from Mariquita to Cali in Colombia (TransGas); and
- a 30 per cent interest in a natural gas transmission system extending from Loma de la Lata, Argentina to Concepción, Chile (Gas Pacifico), and in an industrial natural gas marketing company based in Concepción (INNERGY).

TCPL is constructing pipelines or developing pipeline projects, which it expects to operate, including the following:

- a pipeline under construction that will transport crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, and at Cushing, Oklahoma, and a development project to expand the pipeline and extend it to the Gulf Coast (Keystone);
- a pipeline under construction that will transport natural gas from Wyoming to Northern Border in North Dakota (Bison); and
- a pipeline under construction in Mexico that will transport natural gas from Manzanillo to Guadalajara (Guadalajara).

Energy

The Energy segment consists primarily of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities. Through its Energy segment, the Company owns and operates:

- natural gas-fired cogeneration plants in Alberta at Carseland, Redwater, Bear Creek and MacKay River;
- a waste-heat fuelled power plant at the Cancarb thermal carbon black facility in Medicine Hat, Alberta (Cancarb);
- a natural gas and oil-fired generating facility in Queens, New York, consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology (Ravenswood);
- hydroelectric generation assets located in New Hampshire, Vermont and Massachusetts (TC Hydro);
- a natural gas-fired, combined-cycle plant in Burrillville, Rhode Island (Ocean State Power);
- a natural gas-fired cogeneration plant near Trois-Rivières, Québec (Bécancour);
- a natural gas-fired cogeneration plant near Saint John, New Brunswick (Grandview);
- a natural gas storage facility near Edson, Alberta (Edson); and
- the first phase of a two-phase wind power project located in Kibby and Skinner Townships in northwestern Franklin County, Maine (Kibby Wind).

TCPL does not operate but through its Energy segment has ownership interests in power generation plants and non-regulated natural gas storage facilities as follows:

- a 48.8 per cent partnership interest and a 31.6 per cent partnership interest in the nuclear power generation facilities of Bruce A and Bruce B (collectively Bruce Power), respectively, located near Tiverton, Ontario;
- a 62 per cent interest in the Baie-des-Sables, Anse-à-Valleau and Carleton wind farms, three of five planned wind farms in Gaspé, Québec (Cartier Wind);
- a 60 per cent interest in an underground natural gas storage facility near Crossfield, Alberta (CrossAlta); and
- a 50 per cent interest in a natural gas-fired, combined-cycle cogeneration plant in Toronto, Ontario (Portlands Energy).

TCPL also has long-term power purchase arrangements (PPA) in place for:

- 100 per cent of the production of the Sundance A power facilities and, through a partnership, 50 per cent of the production of the Sundance B power facilities near Wabamun, Alberta; and
- 756 megawatts (MW) of the generating capacity from the Sheerness power facility near Hanna, Alberta.

TCPL has interests in the following Energy projects under construction or development:

- a natural gas-fired, combined-cycle power plant under construction near Toronto, Ontario (Halton Hills);
- a natural gas-fired, simple-cycle peaking power plant under construction in Coolidge, Arizona (Coolidge);

the second phase of the two-phase Kibby Wind power project under construction;

a 62 per cent interest in the Gros-Morne and Montagne-Sèche wind farms under construction, the fourth and fifth wind farms in Cartier Wind; and

a natural gas-fired, combined-cycle power plant in development near Oakville, Ontario (Oakville).

NOTE 2 ACCOUNTING POLICIES

The Company's consolidated financial statements have been prepared by management in accordance with GAAP. Amounts are stated in Canadian dollars unless otherwise indicated. Certain comparative figures have been reclassified to conform with the current year's presentation.

In preparing these financial statements, TCPL is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses as the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgment in making these estimates and assumptions. In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies summarized below.

Basis of Presentation

The consolidated financial statements include the accounts of TCPL and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control. To the extent there are interests owned by other parties, the other parties' interests are included in Non-Controlling Interests. TCPL proportionately consolidates its share of the accounts of joint ventures in which the Company is able to exercise joint control. TCPL uses the equity method of accounting for investments over which the Company is able to exercise significant influence.

Regulation

The Canadian regulated natural gas pipelines are subject to the authority of the National Energy Board (NEB) of Canada. Effective April 2009, the Alberta System became subject to the authority of the NEB. Prior to that date the Alberta System was regulated by the Alberta Utilities Commission (AUC). The natural gas pipelines and regulated storage assets in the U.S. are subject to the authority of the U.S. Federal Energy Regulatory Commission (FERC). These natural gas transmission operations are regulated with respect to construction, operations and the determination of tolls. The timing of recognition of certain revenues and expenses in these regulated businesses may differ from that otherwise expected under GAAP to appropriately reflect the economic impact of the regulators' decisions regarding revenues and tolls.

Revenue Recognition

Pipelines

In the Pipelines segment, revenues from Canadian operations subject to rate regulation are recognized in accordance with decisions made by the NEB. Revenues from U.S. operations subject to rate regulation are recorded in accordance with FERC rules and regulations. The Company's natural gas pipeline revenues are generally based on quantity of gas delivered or contracted capacity. Revenues are recognized on firm contracted capacity over the contract period. For interruptible or volumetric-based services, revenues are recorded when physical delivery is made. The Company's natural gas pipelines that are subject to rate proceedings may have to refund a portion of the revenues they collect depending on the outcome of future rate proceedings. Revenues from non-regulated operations are recorded when products have been delivered or services have been performed.

Energy

i) Power

Revenues from the Company's power business are primarily derived from the sale of electricity through energy marketing activities and from the sale of unutilized natural gas fuel, which are recorded at the time of delivery. Revenues also include capacity payments and ancillary services, which are earned monthly, and revenues earned through the use of energy derivative contracts. The accounting for energy derivative contracts is described in the Financial Instruments section of this note.

ii) Natural Gas Storage

Revenues earned from providing natural gas storage services are recognized in accordance with the terms of the natural gas storage contracts. Revenues earned on the sale of proprietary natural gas are recorded in the month of delivery. Forward contracts for the purchase or sale of natural gas, as well as proprietary natural gas inventory held in storage, are recorded at fair value with changes in fair value recorded in Revenues.

Cash and Cash Equivalents

The Company's cash and cash equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

Inventories

Inventories primarily consist of materials and supplies, including spare parts, and fuel, and are carried at the lower of average cost and net realizable value. The Company values its proprietary natural gas inventory held in storage at fair value, as measured by a weighted average of forward prices for the following four months less selling costs. To record inventory at fair value, TCPL has designated its natural gas storage business as a broker/trader business that purchases and sells natural gas on a back-to-back basis. The Company records its net proprietary natural gas storage sales and purchases in Revenues. All changes in the fair value of proprietary natural gas inventory held in storage are reflected in Inventories and Revenues.

Plant, Property and Equipment

Pipelines

Plant, property and equipment of the Pipelines segment are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and compression equipment are depreciated at annual rates ranging from one per cent to 25 per cent and metering and other plant equipment are depreciated at various rates. The cost of regulated pipelines includes an allowance for funds used during construction (AFUDC) consisting of a debt component and an equity component based on the rate of return on rate base approved by regulators. This allowance is reflected as an increase in the cost of the assets on the Balance Sheet. Interest is capitalized during construction of non-regulated pipelines. The equity component of AFUDC is a non-cash expenditure.

When regulated pipelines retire plant, property and equipment from service, the original book cost is removed from the gross plant amount and recorded as a reduction to Accumulated Depreciation. Costs incurred to remove a plant from service, net of any salvage proceeds, are also recorded in Accumulated Depreciation.

Energy

Major power generation and natural gas storage plant, equipment and structures in the Energy segment are recorded at cost and depreciated once the assets are ready for their intended use on a straight-line basis over estimated service lives at average annual rates ranging from two per cent to ten per cent. Nuclear power generation assets under capital lease are recorded initially 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 and the 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 facilities 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.

Impairment of Long-Lived Assets

The Company reviews long-lived assets such as plant, property and equipment, and intangible assets for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows is less than the carrying value of the assets, an impairment loss is recognized for the excess of the carrying value over the fair value of the assets.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the purchase method of accounting and, accordingly, the assets and liabilities of the acquired entities are recorded at their estimated fair value at the date of acquisition. Goodwill is not amortized and is tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset might be impaired. An initial assessment is made by comparing the fair value of the operations, which includes goodwill, to the book value of each reporting unit. If the fair value is less than book value, an impairment is indicated and a second test is performed to measure the amount of the impairment. In the second test, the implied fair value of the goodwill is calculated by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of the goodwill exceeds the calculated implied fair value of the goodwill, an impairment charge is recorded.

Power Purchase Arrangements

A PPA is a long-term contract for the purchase or sale of power on a predetermined basis. The initial payments for the PPAs were deferred and amortized on a straight-line basis over the term of the contracts, which expire in 2017 and 2020. The PPAs under which TCPL buys power are accounted for as operating leases. A portion of these PPAs has been subleased to third parties under similar terms and conditions. The subleases are accounted for as operating leases and TCPL records the margin earned from the subleases as a component of Revenues.

Income Taxes

The Company uses the liability method of accounting for income taxes, which requires the recognition of future income tax assets and liabilities 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 at the Balance Sheet date that are anticipated to apply to taxable income in the years in which temporary differences are anticipated to be recovered or settled. Changes to these balances are recognized in income in the period during which they occur.

Prior to January 1, 2009, the Company used the taxes payable method of accounting for income taxes for tollmaking purposes for Canadian regulated natural gas transmission operations, as prescribed by regulators. This method was also used for accounting purposes as permitted by GAAP, since there was a reasonable expectation that future taxes payable would be included in future costs of service and recorded in revenues at that time. The liability method of accounting for income taxes continues to be used for all of the Company's other operations.

Canadian income taxes are not provided on the unremitted earnings of foreign investments that 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 Consolidated Statements of Income, Shareholders' Equity, Comprehensive Income, Accumulated Other Comprehensive Income and Cash Flows are translated at the exchange rates in effect at the time of the transaction. Translation adjustments are reflected in Other Comprehensive Income.

Exchange gains or losses on monetary assets and liabilities are recorded in income except for exchange gains or losses on the principal amounts of foreign currency debt related to the Alberta System, Foothills and Canadian Mainline, which are deferred until they are refunded or recovered in tolls, as permitted by regulatory bodies.

Financial Instruments

The Company initially records all financial instruments on the Balance Sheet at their fair value. Subsequent measurement of the financial instruments is based on their classification. Financial assets are classified into the following categories: held for trading, available for sale, held-to-maturity investments and loans and receivables. Financial liabilities are classified as held for trading or other financial liabilities.

Held-for-trading derivative financial assets and liabilities consist of swaps, options, forwards and futures. A financial asset or liability may be designated as held for trading when it is entered into with the intention of generating a profit. The Company has not designated any non-derivative financial assets or liabilities as held for trading. Commodity held-for-trading financial instruments are initially recorded at their fair value and changes to fair value are included in Revenues. Changes in the fair value of interest rate and foreign exchange rate held-for-trading instruments are recorded in Interest Expense and in Interest Income and Other, respectively. Realized gains and losses are included in the same financial category as their underlying position upon settlement of the financial instrument.

The available-for-sale classification includes non-derivative financial assets that are designated as available for sale or are not included in any of the other three classifications. TCPL's available-for-sale financial instruments include fixed-income securities held for self-insurance. These instruments are accounted for initially at their fair value and changes to fair value are recorded through Other Comprehensive Income. Income from the settlement of available-for-sale financial assets is included in Interest Income and Other.

The held-to-maturity classification consists of non-derivative financial assets that are accounted for at their amortized cost using the effective interest method. The Company does not have any held-to-maturity financial assets.

Trade receivables, loans and other receivables with fixed or determinable payments that are not quoted in an active market are classified as "loans and receivables" and are measured at amortized cost using the effective interest method, net of any impairment. The Company's loans and receivables include trade accounts receivable, interest and non-interest-bearing third-party loans and notes receivable. Interest and other income earned from these financial assets are recorded in Interest Income and Other.

Other financial liabilities consist of liabilities not classified as held for trading. Items in this financial instrument category are recognized at amortized cost using the effective interest method. Interest expense is included in Interest Expense and in Interest Expense of Joint Ventures.

The Company uses derivatives and other financial instruments to manage its exposure to changes in foreign currency exchange rates, interest rates and energy commodity prices. The Company also uses a combination of derivatives and U.S. dollar-denominated debt to manage the foreign currency exposure of its foreign operations.

All derivatives are recorded on the Balance Sheet at fair value, with the exception of non-financial derivatives that were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's expected purchase, sale or usage requirements. Changes in fair value of derivatives that are not designated in a hedging relationship are recorded in Net Income. Derivatives used in hedging relationships are discussed further in the Hedges section of this note.

Derivatives embedded in other financial instruments or contracts (host instrument) are recorded as separate derivatives and are measured at fair value if the economic characteristics of the embedded derivative are not closely related to the host instrument, the terms of the embedded derivative are the same as those of a stand-alone derivative and the total contract is not held for trading or accounted for at fair value. Changes in the fair value of embedded derivatives that are recorded separately are included in Net Income.

The recognition of gains and losses on the derivatives for the Alberta System, Foothills and Canadian Mainline exposures is determined through the regulatory process. The gains and losses on derivatives accounted for as part of rate-regulated accounting are deferred in Regulatory Assets or Regulatory Liabilities.

Transaction costs are defined as incremental costs that are directly attributable to the acquisition, issue or disposal of a financial instrument. The Company offsets long-term debt transaction costs against the associated debt and amortizes these costs using the effective interest method for all costs except those related to the Canadian regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of tolling mechanisms.

The Company records the fair value of its portion of material joint and several guarantees. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees. Guarantees are recorded as an increase to an investment account, Property, Plant and Equipment or a charge to Net Income, and a corresponding liability is recorded in Deferred Amounts.

Hedges

The Company applies hedge accounting to arrangements that qualify for hedge accounting treatment, which include fair value and cash flow hedges, and hedges of foreign currency exposures of net investments in self-sustaining foreign operations. Documentation is prepared at the inception of each hedging arrangement in order to qualify for hedge accounting treatment. In addition, the Company performs an assessment of effectiveness at the inception of the contract and at each reporting date. Hedge accounting is discontinued prospectively when the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk. The changes in fair value are recognized in Net Income. Changes in the fair value of the hedged item, to the extent that the hedging

relationship is effective, are offset by changes in the fair value of the hedging item, which are also recorded in Net Income. Changes in the fair value of foreign exchange and interest rate fair value hedges are recorded in Interest Income and Other and Interest Expense, respectively. When hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to Net Income over the remaining term of the original hedging relationship.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is initially recognized in Other Comprehensive Income, while any ineffective portion is recognized in Net Income in the same financial category as the underlying transaction. When hedge accounting is discontinued, the amounts recognized previously in Accumulated Other Comprehensive Income are reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, during the periods when the variability in cash flows of the hedged item affects Net Income or as the original hedged item settles. Gains and losses on derivatives are reclassified immediately to Net Income from Accumulated Other Comprehensive Income when the hedged item is sold or terminated early, or when an anticipated transaction is no longer expected to occur.

The Company also enters into cash flow hedges and fair value hedges for activities subject to rate regulation. The gains and losses arising from changes in the fair value of these hedges can be recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as rate-regulated assets or liabilities on behalf of the ratepayers. When the hedges are settled, the realized gains or losses are collected from or refunded to the ratepayers in subsequent years.

In hedging the foreign currency exposure of a net investment in a self-sustaining foreign operation, the effective portion of foreign exchange gains and losses on the hedging instruments is recognized in Other Comprehensive Income and the ineffective portion is recognized in Net Income. The amounts recognized previously in Accumulated Other Comprehensive Income are reclassified to Net Income in the event the Company settles its hedging instruments or reduces its investment in a foreign operation.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred, when a legal obligation exists and 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.

The scope and timing of asset retirements related to regulated natural gas pipelines and hydroelectric power plants is uncertain. As a result, the Company has not recorded an amount for asset retirement obligations related to these assets, with the exception of certain abandoned facilities. With respect to the nuclear assets leased by Bruce Power, the Company has not recorded an amount for asset retirement obligations, as Bruce Power leases the assets and the lessor is responsible for decommissioning liabilities under the lease agreement.

Environmental Liabilities

The Company records liabilities on an undiscounted basis for environmental remediation efforts that are likely to occur and where the cost can be reasonably estimated. The estimates, including associated legal costs, are based on available information using existing technology and enacted laws and regulations. The estimates are subject to revision in future periods based on actual costs incurred or new circumstances. Amounts expected to be recovered from other parties, including insurers, are recorded as an asset separate from the associated liability.

Emission allowances or credits purchased for compliance are recorded on the Balance Sheet at historical cost and expensed when they are retired. Compliance payments are expensed when incurred. Allowances granted to or internally generated by TCPL are not attributed a value for accounting purposes. When required, TCPL accrues emission liabilities on the Balance Sheet upon the generation or sale of power using the best estimate of the amount required to settle the obligation. Allowances or credits not used for compliance are sold and recorded in Revenues.

Employee Benefit and Other Plans

The Company sponsors defined benefit pension plans (DB Plans), defined contribution plans (DC Plans), a Savings Plan and other post-employment benefit plans. Contributions made by the Company to the DC Plans and Savings Plan are expensed when incurred. The cost of the DB Plans and other post-employment benefits received by employees is actuarially determined using the projected benefit method pro-rated based on service and management's best estimate of expected plan investment performance, salary escalation, retirement age of employees and expected health care costs.

The DB Plans' assets are measured at fair value. The expected return on the DB Plans' assets is determined using market-related values based on a five year moving average value for all of the DB Plans' assets. Past service costs are amortized over the expected average remaining service life of the employees. 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 net actuarial gains or losses over ten per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, 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 medium-term incentive plans, under which payments are made to eligible employees. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, benefits vest when certain conditions are met, including the employees' continued employment during a specified period and achievement of specified corporate performance targets.

Certain of the Company's joint ventures sponsor DB Plans. The Company records its proportionate share of expenses, funding contributions and accrued benefit assets and liabilities related to these plans.

NOTE 3 ACCOUNTING CHANGES

Changes in Accounting Policies for 2009

Rate-Regulated Operations

Effective January 1, 2009, the temporary exemption was withdrawn from the Canadian Institute of Chartered Accountants (CICA) Handbook Section 1100 "Generally Accepted Accounting Principles", which permitted the recognition and measurement of assets and liabilities arising from rate regulation. In addition, Section 3465 "Income Taxes" was amended to require the recognition of future income tax assets and liabilities for rate-regulated operations. In accordance with the CICA Handbook accounting hierarchy, the Company chose to adopt accounting policies consistent with the U.S. Financial Accounting Standards Board's (FASB) Accounting Standards Codification (ASC) Topic 980 "Regulated Operations". As a result, TCPL retained its current method of accounting for its rate-regulated operations, except that the Company is required to recognize future income tax assets and liabilities, instead of using the taxes payable method, and records an offsetting adjustment to regulatory assets and liabilities. As a result of adopting this accounting change, additional future income tax liabilities and a regulatory asset in the amount of $1.4 billion were recorded January 1, 2009 in each of Future Income Taxes and Regulatory Assets.

Adjustments to the 2009 financial statements have been made in accordance with the transitional provisions for Section 3465, which required a cumulative adjustment in the current period to Future Income Taxes and Regulatory Assets. Restatement of prior periods' financial statements was not permitted under Section 3465.

Goodwill and Intangible Assets

Effective January 1, 2009, the Company adopted CICA Handbook Section 3064 "Goodwill and Intangible Assets", which replaced Section 3062 "Goodwill and Other Intangible Assets". Section 3064 gives guidance on the recognition of intangible assets and on the recognition and measurement of internally developed intangible assets. In addition, Section 3450 "Research and Development Costs" was withdrawn from the CICA Handbook. Adopting this accounting change did not have a material effect on the Company's financial statements.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities

Effective January 1, 2009, the Company adopted the accounting provisions of Emerging Issues Committee (EIC) Abstract EIC 173, "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". Under EIC 173 an entity's own credit risk and the credit risk of its counterparties are taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments. Adopting this accounting change did not have a material effect on the Company's financial statements.

Future Accounting Changes

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests

The CICA Handbook Section 1582 "Business Combinations" is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting the standard is expected to have a material effect on the way the Company accounts for future business combinations. Entities adopting Section 1582 will also be required to adopt CICA Handbook Sections 1601 "Consolidated Financial Statements" and 1602 "Non-Controlling Interests". These standards will require non-controlling interests to be presented as part of Shareholders' Equity on the balance sheet. In addition, the income statement of the controlling parent will include 100 per cent of the subsidiary's results and present the allocation between the controlling and non-controlling interests. These standards will be effective January 1, 2011, with early adoption permitted. The changes resulting from adopting Section 1582 will be applied prospectively and the changes from adopting Sections 1601 and 1602 will be applied retrospectively.

International Financial Reporting Standards

The CICA's Accounting Standards Board announced that Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. Effective January 1, 2011, the Company will begin reporting under IFRS.

TCPL currently follows specific accounting policies unique to a rate-regulated business. TCPL has established a project team to support adopting IFRS. The project team is actively monitoring developments regarding potential future guidance on the applicability of certain aspects of rate-regulated accounting under IFRS. Developments in this area could have a significant effect on the scope of the Company's IFRS project and on TCPL's financial results under IFRS. On July 23, 2009, the IASB issued an exposure draft "Rate-regulated Activities". The Company is assessing the impact of developments related to the exposure draft.

As a result of proposed changes to certain IFRS, together with the current stage of the Company's IFRS project, TCPL cannot reasonably quantify the full impact that adopting IFRS will have on its financial position and future results.

NOTE 4 SEGMENTED INFORMATION

Effective January 1, 2009, TCPL revised its presentation of certain income and expense items in the Consolidated Statement of Income to better reflect the operating and financing structure of the Company. To conform with the new presentation, certain of the income and expense amounts pertaining to operations that were previously classified on the Consolidated Income Statement as Other Expenses/(Income) are now included in Operating and Other Expenses/(Income). Depreciation expense has been redefined as Depreciation and Amortization expense and includes amortization of $58 million in 2009 (2008 and 2007 $58 million), for PPAs, which was previously included in Commodity Purchases Resold. Support services costs previously allocated to Pipelines and Energy of $112 million in 2009 (2008 $106 million; 2007 $97 million) are now included in Corporate. In addition, amounts related to Interest Expense and Interest Expense of Joint Ventures, Interest Income and Other, Income Taxes and Non-Controlling Interests are no longer reported on a segmented basis. Segmented information has been retroactively reclassified to reflect these changes. These changes had no impact on reported consolidated Net Income.

Year ended December 31, 2009 (millions of dollars)	**Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	**4,729**	**4,237**		**8,966**
Plant operating costs and other	**(1,655)**	**(1,595)**	**(117)**	**(3,367)**
Commodity purchases resold		**(1,511)**		**(1,511)**
Other income	**48**	**1**		**49**
	3,122	**1,132**	**(117)**	**4,137**
Depreciation and amortization	**(1,030)**	**(347)**		**(1,377)**
	2,092	**785**	**(117)**	**2,760**
Interest expense				**(986)**
Interest expense of joint ventures				**(64)**
Interest income and other				**119**
Income taxes				**(376)**
Non-controlling interests				**(74)**
Net Income				**1,379**
Preferred Share Dividends				**(22)**
Net Income Applicable to Common Shares				**1,357**

Year ended December 31, 2008 (millions of dollars)	**Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	4,650	3,969		8,619
Plant operating costs and other	(1,645)	(1,259)	(110)	(3,014)
Commodity purchases resold		(1,501)		(1,501)
Calpine bankruptcy settlements	279			279
Writedown of Broadwater LNG project costs		(41)		(41)
Other income	31	1	6	38
	3,315	1,169	(104)	4,380
Depreciation and amortization	(989)	(258)		(1,247)
	2,326	911	(104)	3,133
Interest expense				(962)
Interest expense of joint ventures				(72)
Interest income and other				42
Income taxes				(591)
Non-controlling interests				(108)
Net Income				1,442
Preferred Share Dividends				(22)
Net Income Applicable to Common Shares				1,420

Year ended December 31, 2007 (millions of dollars)	**Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	4,712	4,116		8,828
Plant operating costs and other	(1,590)	(1,336)	(104)	(3,030)
Commodity purchases resold	(72)	(1,829)		(1,901)
Other income	27	19	2	48
	3,077	970	(102)	3,945
Depreciation and amortization	(1,021)	(216)		(1,237)
	2,056	754	(102)	2,708
Interest expense				(961)
Interest expense of joint ventures				(75)
Interest income and other				118
Income taxes				(483)
Non-controlling interests				(75)
Net Income				1,232
Preferred Share Dividends				(22)
Net Income Applicable to Common Shares				1,210

TOTAL ASSETS

December 31 (millions of dollars)	**2009**	2008
Pipelines	**29,508**	25,020
Energy	**12,477**	12,006
Corporate	**2,685**	3,709
	44,670	40,735

GEOGRAPHIC INFORMATION

Year ended December 31 (millions of dollars)	**2009**	2008	2007
Revenues[1]			
Canada domestic	**5,177**	4,599	5,019
Canada export	**756**	1,125	1,006
United States and other	**3,033**	2,895	2,803
	8,966	8,619	8,828

(1) Revenues are attributed based on the country in which the product or service originated.

December 31 (millions of dollars)	**2009**	2008
Plant, Property and Equipment		
Canada	**20,266**	18,041
United States	**12,441**	10,973
Mexico	**172**	175
	32,879	29,189

CAPITAL EXPENDITURES

Year ended December 31 (millions of dollars)	**2009**	2008	2007
Pipelines	**3,904**	1,854	564
Energy	**1,487**	1,266	1,079
Corporate	**26**	14	8
	5,417	3,134	1,651

NOTE 5 PLANT, PROPERTY AND EQUIPMENT

		2009			2008	
December 31 (millions of dollars)	**Cost**	**Accumulated Depreciation**	**Net Book Value**	Cost	Accumulated Depreciation	Net Book Value
Pipelines[1]						
Canadian Mainline						
Pipeline	**8,752**	**4,501**	**4,251**	8,740	4,269	4,471
Compression	**3,379**	**1,529**	**1,850**	3,373	1,399	1,974
Metering and other	**364**	**153**	**211**	344	140	204
	12,495	**6,183**	**6,312**	12,457	5,808	6,649
Under construction	**27**		**27**	16		16
	12,522	**6,183**	**6,339**	12,473	5,808	6,665
Alberta System						
Pipeline	**6,002**	**2,777**	**3,225**	5,518	2,637	2,881
Compression	**1,696**	**983**	**713**	1,552	914	638
Metering and other	**879**	**342**	**537**	846	317	529
	8,577	**4,102**	**4,475**	7,916	3,868	4,048
Under construction	**281**		**281**	354		354
	8,858	**4,102**	**4,756**	8,270	3,868	4,402
ANR						
Pipeline	**848**	**79**	**769**	976	69	907
Compression	**489**	**65**	**424**	579	61	518
Metering and other	**646**	**67**	**579**	686	50	636
	1,983	**211**	**1,772**	2,241	180	2,061
Under construction	**23**		**23**	31		31
	2,006	**211**	**1,795**	2,272	180	2,092
GTN[2]						
Pipeline	**1,135**	**205**	**930**	1,482	215	1,267
Compression	**414**	**59**	**355**	562	63	499
Metering and other	**93**	**22**	**71**	134	23	111
	1,642	**286**	**1,356**	2,178	301	1,877
Under construction	**22**		**22**	30		30
	1,664	**286**	**1,378**	2,208	301	1,907
Keystone under construction	**5,305**		**5,305**	1,361		1,361
Joint Ventures and Others						
Great Lakes	**1,608**	**694**	**914**	1,875	744	1,131
Foothills	**1,645**	**917**	**728**	1,655	873	782
Northern Border	**1,316**	**613**	**703**	1,530	682	848
Other[2][3]	**2,307**	**587**	**1,720**	2,078	566	1,512
	6,876	**2,811**	**4,065**	7,138	2,865	4,273
	37,231	**13,593**	**23,638**	33,722	13,022	20,700

Energy						
Nuclear[4]	**1,769**	**451**	**1,318**	1,604	364	1,240
Natural gas Ravenswood	**1,712**	**82**	**1,630**	1,977	22	1,955
Natural gas Other[5][6]	**2,032**	**522**	**1,510**	1,702	504	1,198
Hydro	**625**	**56**	**569**	628	48	580
Wind[7]	**611**	**41**	**570**	391	18	373
Natural gas storage	**418**	**56**	**362**	374	46	328
Other	**156**	**89**	**67**	156	82	74
	7,323	**1,297**	**6,026**	6,832	1,084	5,748
Under construction Nuclear[8]	**1,845**		**1,845**	1,463		1,463
Under construction Other[9]	**1,287**		**1,287**	1,224		1,224
	10,455	**1,297**	**9,158**	9,519	1,084	8,435
Corporate	**110**	**27**	**83**	74	20	54
	47,796	**14,917**	**32,879**	43,315	14,126	29,189

(1) In 2009, the Company capitalized $33 million (2008 $27 million) relating to the equity portion of AFUDC on natural gas pipelines.

(2) GTN's results include North Baja until July 1, 2009 when it was sold to PipeLines LP.

(3) Pipelines Other includes assets of Portland, Iroquois, TQM, North Baja, Tamazunchale, Ventures LP and Tuscarora, and expenditures of $200 million (2008 nil) and $29 million (2008 nil) for the construction of Bison and Guadalajara, respectively.

(4) Includes assets under capital lease relating to Bruce Power.

(5) Includes facilities with long-term PPAs that are accounted for as operating leases. The cost and accumulated depreciation of these facilities were $93 million and $17 million, respectively, at December 31, 2009 (2008 $90 million and $13 million, respectively). Revenues of $15 million were recognized in 2009 (2008 $14 million; 2007 $16 million) through the sale of electricity under the related PPAs.

(6) Includes Portlands Energy as of April 2009.

(7) Includes phase one of Kibby Wind as of October 30, 2009.

(8) Nuclear assets under construction primarily includes expenditures for the refurbishment and restart of Bruce A.

(9) Other Energy assets under construction at December 31, 2009 includes expenditures for the construction of Halton Hills, Coolidge, the second phase of Kibby Wind and two Cartier wind farms, Gros-Morne and Montagne-Sèche.

NOTE 6 GOODWILL

The Company has recorded the following goodwill on its acquisitions in the U.S.:

(millions of dollars)	Pipelines	Energy	Total
Balance at January 1, 2008	2,633		2,633
Acquisition of Ravenswood		949	949
Foreign exchange and adjustments	749	66	815
Balance at December 31, 2008	3,382	1,015	4,397
Foreign exchange and adjustments	**(491)**	**(143)**	**(634)**
Balance at December 31, 2009	**2,891**	**872**	**3,763**

NOTE 7 INTANGIBLES AND OTHER ASSETS

December 31 (millions of dollars)	**2009**	2008
PPAs(1)	**593**	651
Deferred project development costs(2)	**470**	116
Loans and advances(3)(4) (Note 24)	**417**	140
Pension and other benefit plans (Note 22)	**383**	234
Fair value of derivative contracts (Note 18)	**260**	191
Equity investments(5)	**84**	85
Prepaid operating lease(3)		369
Other	**293**	241
	2,500	2,027

(1) The following amounts related to PPAs are included in the consolidated financial statements:

	2009			2008		
December 31 (millions of dollars)	**Cost**	**Accumulated Amortization**	**Net Book Value**	Cost	Accumulated Amortization	Net Book Value
PPAs	**915**	**322**	**593**	915	264	651

Amortization expense for the PPAs was $58 million for the year ended December 31, 2009 (2008 and 2007 $58 million). The expected annual amortization expense in each of the next five years is: 2010 $58 million; 2011 $57 million; 2012 $57 million; 2013 $57 million; and 2014 $57 million.

(2) The balance of $470 million at December 31, 2009 (2008 $74 million) related to the proposed expansion of Keystone. The balance at December 31, 2008 included $42 million related to the Bison pipeline project, which was included in Plant, Property and Equipment in 2009. In 2008, TCPL wrote down $41 million of capitalized costs related to the Broadwater liquefied natural gas (LNG) project after the New York Department of State rejected a proposal to construct this facility. Annual project development expenditures are included in Deferred Amounts and Other in Consolidated Cash Flows.

(3) Upon acquisition of Ravenswood in August 2008, an operating lease was prepaid in the amount of $322 million. Pursuant to the terms of the Ravenswood acquisition agreement in March 2009, TCPL also acquired the lessor entity, thereby eliminating the prepaid operating lease upon consolidation. As at December 31, 2009, TCPL held a $317 million note receivable from the August 2008 seller of

Ravenswood which bears interest at 6.75 per cent and matures in 2039. Loans and advances includes $274 million representing the long-term portion of this note receivable.

(4) As at December 31, 2009, loans and advances includes a $143 million (2008 $140 million) loan to the APG to finance its one-third share of project development costs related to the Mackenzie Gas Pipeline project. The ability to recover this investment remains dependent upon a successful outcome of the project.

(5) The balance primarily relates to the Company's 46.5 per cent ownership interest in TransGas.

NOTE 8 JOINT VENTURE INVESTMENTS

		TCPL's Proportionate Share				
		Income/(Loss) Before Income Taxes Year Ended December 31			Net Assets December 31	
(millions of dollars)	Ownership Interest as at December 31, 2009	**2009**	2008	2007	**2009**	2008
Pipelines						
Northern Border[1]		**47**	59	67	**420**	479
Iroquois	44.5%	**44**	32	25	**183**	239
TQM	50.0%	**22**	12	11	**82**	69
Keystone[2]			(7)	n/a[3]		906
Great Lakes[4]				13		
Other	Various	**17**	15	13	**56**	70
Energy						
Bruce A	48.8%	**3**	46	8	**2,386**	2,012
Bruce B	31.6%	**236**	136	140	**580**	429
CrossAlta	60.0%	**55**	44	59	**77**	56
Cartier Wind[5]	62.0%	**26**	12	10	**327**	365
Portlands Energy[6]	50.0%	**24**			**358**	334
Other	Various	**4**	9	5	**99**	101
		478	358	351	**4,568**	5,060

(1) The results reflect a 50 per cent interest in Northern Border as a result of the Company fully consolidating PipeLines LP. Through TCPL's 38.2 per cent (2008 and 2007 32.1 per cent) ownership interest in PipeLines LP, its effective ownership of Northern Border, net of non-controlling interests, was 19.1 per cent at December 31, 2009 (2008 and 2007 16.1 per cent).

(2) In August 2009, TCPL purchased ConocoPhillips' remaining ownership interest in Keystone of approximately 20 per cent, increasing TCPL's ownership interest to 100 per cent. As of the acquisition date, the Company began fully consolidating Keystone on a prospective basis. At December 31, 2008, TCPL's equity ownership in the Keystone partnerships was 61.9 per cent (December 31, 2007 50.0 per cent). Strategic, operational and financial decisions were made jointly with ConocoPhillips until August 2009.

(3) Not applicable, as there were no comparative amounts in 2007.

(4) TCPL has a direct ownership interest in Great Lakes of 53.6 per cent, and an indirect 17.7 per cent interest (2008 and 2007 14.9 per cent) through its 38.2 per cent (2008 and 2007 32.1 per cent) ownership interest in PipeLines LP. The Company's total effective ownership interest in Great Lakes, net of non-controlling interests, was 71.3 per cent at December 31, 2009 (2008 and 2007 68.5 per cent). TCPL commenced consolidating its investment in Great Lakes on a prospective basis effective February 2007.

(5) TCPL proportionately consolidates its 62 per cent interest in the Cartier Wind assets. The second and third phases of the five-phase Cartier Wind project, Anse-à-Valleau and Carleton, began operating in November 2007 and 2008, respectively.

(6) Portlands Energy began operating in April 2009.

Summarized Financial Information of Joint Ventures

Year ended December 31 (millions of dollars)	**2009**	2008	2007
Income			
Revenues	**1,418**	1,264	1,305
Plant operating costs and other	**(676)**	(683)	(736)
Depreciation and amortization	**(196)**	(154)	(150)
Interest expense and other	**(68)**	(69)	(68)
Proportionate Share of Joint Venture Income Before Income Taxes	**478**	358	351

Year ended December 31 (millions of dollars)	**2009**	2008	2007
Cash Flows			
Operating activities	**203**	389	59
Investing activities	**(399)**	(1,754)	(400)
Financing activities[1]	**130**	1,353	409
Effect of foreign exchange rate changes on cash and cash equivalents	**(17)**	23	(8)
Proportionate Share of (Decrease)/Increase in Cash and Cash Equivalents of Joint Ventures	**(83)**	11	60

(1) Financing activities included cash outflows resulting from distributions paid to TCPL of $252 million in 2009 (2008 $287 million; 2007 $361 million) and cash inflows resulting from capital contributions paid by TCPL of $864 million in 2009 (2008 $1,170 million; 2007 $771 million).

December 31 (millions of dollars)	**2009**	2008
Balance Sheet		
Cash and cash equivalents	**98**	181
Other current assets	**552**	560
Plant, property and equipment	**5,239**	6,341
Intangibles and other assets/(deferred amounts), net	**5**	45
Current liabilities	**(572)**	(1,196)
Long-term debt	**(753)**	(869)
Future income taxes	**(1)**	(2)
Proportionate Share of Net Assets of Joint Ventures	**4,568**	5,060

NOTE 9 ACQUISITIONS AND DISPOSITIONS

Pipelines

Keystone

In August 2009, TCPL purchased ConocoPhillips' remaining ownership interest in Keystone of approximately 20 per cent for US$553 million plus the assumption of US$197 million of short-term debt. The acquisition increased TCPL's ownership interest in Keystone to 100 per cent and was recorded in Plant, Property and Equipment. The purchase price reflected ConocoPhillips' capital contributions to date and included capitalization of interest during construction. TCPL began fully consolidating Keystone into its Pipelines segment upon acquisition.

In 2008, TCPL entered into an agreement with ConocoPhillips to increase its equity ownership in Keystone to approximately 80 per cent from 50 per cent, with ConocoPhillips' equity ownership in Keystone being reduced concurrently to approximately 20 per cent from 50 per cent. In 2008 and prior to August 2009 TCPL funded 100 per cent of the construction expenditures until the participants' project capital contributions were aligned with their revised ownership interests. In 2009, prior to August, TCPL funded $1.3 billion of cash calls for Keystone, resulting in the Company acquiring an incremental increase in ownership of approximately 18 per cent for $313 million. In 2008, the Company funded $362 million of cash calls, resulting in an incremental increase in ownership of approximately 12 per cent for $176 million. TCPL's ownership interest was approximately 80 per cent and 62 per cent in August 2009 and December 31, 2008, respectively. TCPL proportionately consolidated the Keystone partnerships prior to August 2009.

During 2008, Keystone purchased pipeline facilities located in Saskatchewan and Manitoba from the Canadian Mainline for use in the construction of the Keystone oil pipeline. The sale was completed in three phases for total proceeds of $67 million, with no gain recognized on the sale.

ANR and Great Lakes

On February 22, 2007, TCPL acquired from El Paso Corporation 100 per cent of ANR and an additional 3.6 per cent interest in Great Lakes for a total of US$3.4 billion, including US$491 million of assumed long-term debt. The acquisitions were accounted for using the purchase method of accounting. TCPL began consolidating ANR and Great Lakes into the Pipelines segment upon acquisition. The purchase price was allocated as follows:

Purchase Price Allocation

(millions of US dollars)	ANR	Great Lakes	Total
Current assets	250	4	254
Plant, property and equipment	1,617	35	1,652
Other non-current assets	83		83
Goodwill	1,945	32	1,977
Current liabilities	(179)	(3)	(182)
Long-term debt	(475)	(16)	(491)
Other non-current liabilities	(357)	(19)	(376)
	2,884	33	2,917

TC PipeLines, LP Acquisition of Interest in Great Lakes

On February 22, 2007, PipeLines LP acquired from El Paso Corporation a 46.4 per cent interest in Great Lakes for US$942 million, including US$209 million of assumed long-term debt. The acquisition was accounted for using the purchase method of accounting. TCPL began consolidating Great Lakes into its Pipelines segment after the acquisition date.

Purchase Price Allocation

(millions of US dollars)	
Current assets	42
Plant, property and equipment	465
Other non-current assets	1
Goodwill	457
Current liabilities	(23)
Long-term debt	(209)
	733

The allocation of the purchase price for these transactions was made using the fair value of the net assets at the date of acquisition. Tolls charged by ANR and Great Lakes are subject to rate regulation based on historical costs. As a result, the regulated net assets, other than ANR's gas held for sale, were determined to have a fair value equal to their rate-regulated value.

Factors that contributed to goodwill included the opportunity to expand further in the U.S. market and to gain a stronger competitive position in the North American gas transmission business. Goodwill related to TCPL's ANR and Great Lakes transactions is not amortizable for tax purposes. Goodwill related to PipeLines LP's Great Lakes transaction is amortizable for tax purposes.

TC PipeLines, LP

On November 18, 2009, PipeLines LP completed an offering of five million common units at a price of US$38.00 per unit. The issue resulted in net proceeds to PipeLines LP of US$182 million. TCPL contributed an additional US$3.8 million to maintain its general partnership interest but did not purchase any other units. Upon completion of the offering, the Company's ownership interest in PipeLines LP decreased to 38.2 per cent and the Company recognized a dilution gain of $18 million after tax ($29 million pre-tax).

On July 1, 2009, TCPL sold North Baja to PipeLines LP. As part of the transaction, TCPL agreed to amend its general partner incentive distribution rights arrangement with PipeLines LP. TCPL received aggregate consideration totalling approximately US$395 million from PipeLines LP, including US$200 million in cash and 6,371,680 common units of PipeLines LP. TCPL recorded no gain or loss as a result of the transaction. TCPL's ownership in PipeLines LP increased to 42.6 per cent as a result of the transaction. TCPL's increased ownership in PipeLines LP also resulted in a decrease in Non-Controlling Interests and an increase in Contributed Surplus.

In February 2007, PipeLines LP completed a private placement offering of 17.4 million common units at a price of US$34.57 per unit. TCPL acquired 50 per cent of the units for US$300 million. TCPL also invested an additional US$12 million to maintain its general partnership

interest in PipeLines LP. As a result of these additional investments, TCPL's ownership in PipeLines LP was 32.1 per cent on February 22, 2007. The total private placement, together with TCPL's additional investment, resulted in gross proceeds to PipeLines LP of US$612 million, which were used to partially finance its acquisition of the 46.4 per cent ownership interest in Great Lakes.

Energy

Ravenswood

On August 26, 2008, TCPL acquired from National Grid plc 100 per cent of the 2,480 MW Ravenswood power facility for US$2.9 billion. The acquisition was accounted for using the purchase method of accounting. TCPL began consolidating Ravenswood into its Energy segment after the acquisition date. The purchase price was allocated as follows:

Purchase Price Allocation

(millions of US dollars)

Current assets	128
Plant, property and equipment	1,666
Other non-current assets	305
Goodwill	834
Current liabilities	(11)
Other non-current liabilities	(10)
	2,912

The allocation of the purchase price was made using the fair value of the net assets at the date of acquisition. Factors that contributed to goodwill included the opportunity to expand the Energy segment further into the U.S. market and to gain a stronger competitive position in the North American power generation business. The goodwill recognized on the transaction is amortizable for tax purposes.

Ontario Land Sale

In November 2007, TCPL's Energy segment sold land in Ontario that had previously been held for development, generating net proceeds of $37 million and recognizing an after tax gain of $14 million on the sale.

NOTE 10 LONG-TERM DEBT

Outstanding loan amounts (millions of dollars)	Maturity Dates	**2009** Outstanding December 31	**2009** Interest Rate[1]	2008 Outstanding December 31	2008 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian dollars	2010 to 2020	**1,002**	**10.9%**	1,251	10.8%
U.S. dollars (2009 and 2008 US$600)[2]	2012 to 2021	**626**	**9.5%**	734	9.5%
Medium-Term Notes					
Canadian dollars[3]	2011 to 2039	**4,148**	**6.2%**	3,653	5.3%
Senior Unsecured Notes					
U.S. dollars (2009 US$6,496; 2008 US$4,723)[4]	2010 to 2039	**6,727**	**6.7%**	5,751	6.3%
		12,503		11,389	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian dollars	2010 to 2024	**430**	**11.5%**	439	11.5%
U.S. dollars (2009 and 2008 US$375)	2012 to 2023	**390**	**8.2%**	457	8.2%
Medium-Term Notes					
Canadian dollars	2025 to 2030	**502**	**7.4%**	502	7.4%
U.S. dollars (2009 and 2008 US$33)	2026	**34**	**7.5%**	39	7.5%
		1,356		1,437	
TRANSCANADA PIPELINE USA LTD.					
Bank Loan					
U.S. dollars (2009 and 2008 US$700)	2012	**733**	**0.5%**	857	2.4%
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. dollars (2009 US$443; 2008 US$444)	2010 to 2025	**462**	**9.1%**	541	9.1%
GAS TRANSMISSION NORTHWEST CORPORATION					
Senior Unsecured Notes					
U.S. Dollars (2009 and 2008 US$400)	2010 to 2035	**417**	**5.4%**	488	5.4%
TC PIPELINES, LP					
Unsecured Loan					
U.S. dollars (2009 US$484; 2008 US$475)	2011	**506**	**1.0%**	580	2.7%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. dollars (2009 US$411; 2008 US$430)	2011 to 2030	**429**	**7.8%**	526	7.8%
TUSCARORA GAS TRANSMISSION COMPANY					

Senior Unsecured Notes					
U.S. dollars (2009 US$57; 2008 US$64)	2010 to 2012	**60**	**7.3%**	78	7.4%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Secured Notes(5)					
U.S. dollars (2009 US$180; 2008 US$196)	2018	**186**	**6.1%**	236	6.1%
OTHER					
Senior Notes					
U.S. dollars (2009 US$12; 2008 US$18)	2011	**12**	**7.3%**	22	7.3%
		16,664		16,154	
Less: Current Portion of Long-Term Debt		**478**		786	
		16,186		15,368	

(1) Interest rates are the effective interest rates except for those pertaining to long-term debt issued for the Company's regulated operations, in which case the weighted average interest rate is presented as required by the regulators. Weighted average and effective interest rates are stated as at the respective outstanding dates.

(2) Includes fair value adjustments for interest rate swap agreements on US$50 million of debt at December 31, 2008.

(3) Includes fair value adjustments for interest rate swap agreements on $50 million of debt at December 31, 2008.

(4) Includes fair value adjustments for interest rate swap agreements on US$250 million of debt at December 31, 2009 (2008 US$150 million).

(5) Senior Secured Notes are secured by shipper transportation contracts, existing and new guarantees, letters of credit and collateral requirements.

Principal Repayments

Principal repayments on the long-term debt of the Company for the next five years are approximately as follows: 2010 $478 million; 2011 $923 million; 2012 $1,176 million; 2013 $911 million; and 2014 $968 million.

Debt Shelf Programs TransCanada PipeLines Limited

In December 2009, TCPL filed a debt base shelf prospectus qualifying for the issuance of up to US$4.0 billion of debt securities in the U.S. This prospectus replaced the debt base shelf prospectus filed in January 2009, discussed below. No amounts have been issued under the December 2009 base shelf prospectus.

In April 2009, TCPL filed a $2.0 billion Canadian Medium-Term Notes base shelf prospectus to replace a March 2007 $1.5 billion Canadian Medium-Term Notes base shelf prospectus, which expired in April 2009. No amounts have been issued under the April 2009 base shelf prospectus.

In January 2009, TCPL filed a debt shelf prospectus in the U.S. qualifying for issuance of US$3.0 billion of debt securities. Subsequent to the January 2009 debt issue discussed below, the Company had US$1.0 billion of remaining capacity available under this debt shelf prospectus.

TransCanada PipeLines Limited

In February 2009, TCPL issued Medium-Term Notes of $300 million and $400 million maturing in February 2014 and February 2039, respectively, and bearing interest at 5.05 per cent and 8.05 per cent, respectively. These notes were issued by way of a pricing supplement under a Canadian $1.5 billion debt base shelf prospectus filed in March 2007.

In January 2009, TCPL issued Senior Unsecured Notes of US$750 million and US$1.25 billion maturing in January 2019 and January 2039, respectively, and bearing interest at 7.125 per cent and 7.625 per cent, respectively. These notes were issued by way of a prospectus supplement under the U.S. debt base shelf prospectus filed in January 2009.

In August 2008, TCPL issued $500 million of Medium-Term Notes maturing in August 2013 and bearing interest at 5.05 per cent by way of a pricing supplement under the Canadian debt base shelf prospectus filed in March 2007.

In August 2008, TCPL issued US$850 million and US$650 million of Senior Unsecured Notes maturing in August 2018 and August 2038, respectively, and bearing interest at 6.50 per cent and 7.25 per cent, respectively. These notes were issued by way of a prospectus supplement under a US$2.5 billion debt base shelf prospectus filed in September 2007, which was fully utilized following these issuances.

NOVA Gas Transmission Ltd.

Debentures issued by NOVA Gas Transmission Ltd. (NGTL) in the amount of $225 million have retraction provisions that 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 were made to December 31, 2009.

TransCanada PipeLine USA Ltd.

TransCanada PipeLine USA Ltd. (TCPL USA) has a US$1.0 billion committed, unsecured, syndicated credit facility, guaranteed by TransCanada, consisting of a US$700 million five year term loan maturing in 2012 and a US$300 million, revolving facility maturing in February 2013 described further under Note 20. Included in Long-Term Debt was an outstanding balance of US$700 million on the term loan at December 31, 2009 and 2008.

TC PipeLines, LP

PipeLines LP has available a committed, unsecured syndicated revolving credit and term loan facility of US$725 million maturing December 2011, consisting of a US$475 million senior term loan and a US$250 million senior revolving credit facility. There was an outstanding balance of US$484 million and US$475 million on the credit facility at December 31, 2009 and 2008, respectively.

Interest Expense

Year ended December 31 (millions of dollars)	**2009**	2008	2007
Interest on long-term debt	**1,212**	970	986
Interest on junior subordinated notes	**73**	68	43
Interest on short-term debt	**41**	51	28
Capitalized interest	**(358)**	(141)	(68)
Amortization and other financial charges[1]	**18**	14	(28)
	986	962	961

(1) Amortization and other financial charges includes amortization of transaction costs and debt discounts calculated using the effective interest method.

The Company made interest payments of $956 million in 2009 (2008 $869 million; 2007 $944 million) net of interest capitalized on construction projects.

NOTE 11 LONG-TERM DEBT OF JOINT VENTURES

		2009		2008	
Outstanding loan amounts (millions of dollars)	Maturity Dates	**Outstanding December 31(1)**	**Interest Rate(2)**	Outstanding December 31(1)	Interest Rate(2)
NORTHERN BORDER PIPELINE COMPANY					
Senior Unsecured Notes					
(2009 US$175; 2008 US$225)	2012 to 2021	**182**	**7.2%**	275	7.7%
Bank Facility					
(2009 US$108; 2008 US$96)	2012	**112**	**0.5%**	116	3.4%
IROQUOIS GAS TRANSMISSION SYSTEM, L.P.					
Senior Unsecured Notes					
(2009 US$210; 2008 US$160)	2010 to 2027	**219**	**7.8%**	195	7.6%
BRUCE POWER L.P. AND BRUCE POWER A L.P.					
Capital Lease Obligations	2018	**222**	**7.5%**	235	7.5%
Term Loan	2031	**93**	**7.1%**	95	7.1%
TRANS QUÉBEC & MARITIMES PIPELINE INC.					
Bonds	2010 to 2014	**125**	**5.2%**	137	6.0%
Term Loan	2011	**10**	**0.4%**	18	1.9%
OTHER	2012	**2**	**2.7%**	5	5.5%
		965		1,076	
Less: Current Portion of Long-Term Debt of Joint Ventures		**212**		207	
		753		869	

(1) Amounts outstanding represent TCPL's proportionate share, except for Northern Border, which reflects a 50 per cent interest as a result of the Company fully consolidating PipeLines LP.

(2) Interest rates are the effective interest rates except those pertaining to long-term debt issued for TQM's regulated operations, in which case the weighted average interest rate is presented as required by the regulators. Weighted average and effective interest rates are stated as at the respective outstanding dates. At December 31, 2008, the effective interest rate resulting from swap agreements was 0.5 per cent on the Northern Border bank facility (2008 4.1 per cent).

The long-term debt of joint ventures is non-recourse to TCPL, except that TCPL has provided certain pro-rata guarantees related to the capital lease obligations of Bruce Power. The security provided with respect to the debt of each joint venture is limited to the rights and assets of the joint venture and does not extend to the rights and assets of TCPL, except to the extent of TCPL's investment. Trans Québec & Maritimes Pipeline Inc.'s (TQM Pipeline) bonds are secured by a first interest in all TQM Pipeline real and immoveable property and rights, a floating charge on all residual property and assets, and a specific interest on bonds of TQM Finance Inc. and on rights under all licenses and permits relating to the TQM pipeline system and natural gas transportation agreements.

Subject to meeting certain requirements, the Bruce Power capital lease agreements provide for a series of renewals commencing January 1, 2019. The first renewal is for a period of one year and each of 12 renewals thereafter is for a period of two years.

The Company's proportionate share of principal repayments for the next five years resulting from maturities and sinking fund obligations of the non-recourse joint venture debt is approximately as follows: 2010 $199 million; 2011 $21 million; 2012 $120 million; 2013 $7 million; and 2014 $44 million.

The Company's proportionate share of principal payments for the next five years resulting from the capital lease obligations of Bruce Power is approximately as follows: 2010 $13 million; 2011 $15 million; 2012 $18 million; 2013 $20 million; and 2014 $23 million.

In September 2009, TQM issued $75 million of bonds maturing in September 2014 and bearing interest at 4.05 per cent.

In August 2009, Northern Border issued US$100 million of Senior Unsecured Notes maturing in August 2016 and bearing interest at 6.24 per cent.

In May 2009, Iroquois issued US$140 million Senior Unsecured Notes maturing in May 2019 and bearing interest at 6.63 per cent.

In September 2008, Bruce A entered into a $193 million unsecured term loan maturing December 2031 and bearing interest at 7.1 per cent.

Sensitivity

A one per cent change in interest rates would have the following effect on net income assuming all other variables were to remain constant:

(millions of dollars)	Increase	Decrease
Effect on interest expense of variable interest rate debt	1	(1)

Interest Expense of Joint Ventures

Year ended December 31 (millions of dollars)	**2009**	2008	2007
Interest on long-term debt	**51**	45	50
Interest on capital lease obligations	**17**	18	18
Short-term interest and other financial charges	**6**	7	4
Capitalized interest	**(11)**		
Deferrals and amortization	**1**	2	3
	64	72	75

The Company's proportionate share of the interest payments by joint ventures was $41 million in 2009 (2008 $50 million; 2007 $45 million) net of interest capitalized on construction projects.

The Company's proportionate share of interest payments from the capital lease obligations of Bruce Power was $17 million in 2009 (2008 and 2007 $18 million).

NOTE 12 JUNIOR SUBORDINATED NOTES

		2009		2008	
Outstanding loan amount (millions of dollars)	Maturity Date	**Outstanding December 31**	**Effective Interest Rate**	Outstanding December 31	Effective Interest Rate
TRANSCANADA PIPELINES LIMITED					
U.S. dollars (2009 and 2008 US$1,000)	2017	**1,036**	**6.5%**	1,213	6.5%

Junior Subordinated Notes of US$1.0 billion mature in 2067 and bear interest at 6.35 per cent per year until May 15, 2017, when interest will convert to a floating rate that is reset quarterly to the three-month London Interbank Offered Rate plus 221 basis points. The Company has the option to defer payment of interest for periods of up to ten years without giving rise to a default and without permitting acceleration of payment under the terms of the Junior Subordinated Notes. However, the Company would be prohibited from paying dividends during any such deferral period. The Junior Subordinated Notes are subordinated in right of payment to existing and future senior indebtedness and are effectively subordinated to all indebtedness and other obligations of TCPL. The Junior Subordinated Notes are callable at the Company's option at any time on or after May 15, 2017, at 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption. The Junior Subordinated Notes are callable earlier, in whole or in part, upon the occurrence of certain events and at the Company's option at an amount equal to the greater of 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption and an amount determined by a specified formula in accordance with the terms of the Junior Subordinated Notes.

NOTE 13 DEFERRED AMOUNTS

December 31 (millions of dollars)	**2009**	2008
Fair value of derivative contracts (Note 18)	**272**	694
Employee benefit plans (Note 22)	**235**	219
Asset retirement obligations (Note 21)	**110**	114
Other	**126**	141
	743	1,168

NOTE 14 RATE REGULATED BUSINESSES

TCPL's rate regulated businesses currently include Canadian and U.S. natural gas pipelines and regulated U.S. natural gas storage. Regulatory assets and liabilities represent future revenues that are expected to be recovered from or refunded to customers based on decisions and approvals by the applicable regulatory authorities. In addition to GAAP financial reporting, TCPL's regulated pipelines file financial reports using accounting regulations required by their respective regulators.

Canadian Regulated Operations

Canadian natural gas transmission services are supplied under natural 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 TCPL's Canadian regulated pipelines are set typically through a process that involves filing an application with the regulators for a change in rates. Regulated rates are underpinned by the total annual revenue requirement, which comprises a specified annual return on capital, including debt and equity, and all necessary operating expenses, taxes and depreciation.

TCPL's Canadian regulated pipelines have generally been subject to a cost-of-service model wherein forecasted costs, including a return on capital, determine the revenues for the upcoming year. To the extent that actual costs and revenues are more or less than the forecasted costs and revenues, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in rates at that time. Costs for which the regulator does not allow the difference between actual and forecast to be deferred are included in the determination of net income in the year they are incurred.

The Canadian Mainline, Alberta System, Foothills and TQM pipelines are regulated by the NEB under the *National Energy Board Act* (Canada). Following an application by TCPL to the NEB requesting a change in regulatory jurisdiction for the Alberta System, the NEB determined that the Alberta System is within federal jurisdiction and subject to NEB regulation effective April 29, 2009. Prior to April 2009, the Alberta System was regulated by the AUC primarily under the provisions of the *Gas Utilities Act (Alberta)* and the *Pipeline Act (Alberta)*. The NEB regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for the Company's Canadian regulated natural gas transmission systems.

In October 2009, the NEB issued a decision that its RH-2-94 Decision, which had established a rate of return on common equity (ROE) formula that formed the basis of determining tolls for pipelines under NEB jurisdiction since 1995, would not continue to be in effect. A company's cost of capital will now be determined by negotiations between pipeline companies and their shippers or by the NEB if a pipeline company files a cost of capital application. This decision impacts TCPL's NEB regulated pipelines, however, the Canadian Mainline will continue to base its return on the RH-2-94 NEB ROE formula for the years 2010 and 2011 in accordance with the terms of the current Canadian Mainline tolls settlement. In November 2009, certain industry stakeholders appealed the October 2009 NEB decision with the Federal Court of Appeal and named the NEB as the sole respondent. TCPL was granted respondent status in the matter and filed its submission opposing the leave application in February 2010.

Canadian Mainline

The Canadian Mainline currently operates under a five-year tolls settlement, which is effective January 1, 2007, to December 31, 2011. Canadian Mainline's cost of capital for establishing tolls under the settlement reflects ROE as determined by the NEB's ROE formula, on a deemed common equity ratio of 40 per cent. The allowed ROE in 2009 for the Canadian Mainline was 8.57 per cent (2008 8.71 per cent). The balance of the capital structure is comprised of short- and long-term debt.

The settlement also establishes the Canadian Mainline's fixed operating, maintenance and administrative (OM&A) costs for each year of the five years. Any variance between actual OM&A costs and those agreed to in the settlement have accrued fully to TCPL from 2007 to 2009. Variances in OM&A costs will be shared equally between TCPL and its customers in 2010 and 2011. All other cost elements of the revenue requirement are treated on a flow-through basis. There are also performance-based incentive arrangements that provide mutual benefits to both TCPL and its customers.

Alberta System

In 2008 and 2009, the Alberta System operated under a two-year revenue requirement settlement approved by the AUC in 2008 and the NEB in 2009. As part of the settlement, fixed costs were established for ROE, income taxes and certain OM&A costs. Any variances between actual costs and those agreed to in the settlement accrue to TCPL, subject to ROE and income tax adjustment mechanisms. All other costs are treated on a flow-through basis.

Foothills

The ROE for Foothills, which is based on the NEB-allowed ROE formula, was 8.57 per cent in 2009 (2008 8.71 per cent) on a deemed equity component of 36 per cent. A component of OM&A costs are fixed, subject to the terms of the BC System/Foothills Integration Settlement, with variances between actual and the fixed amounts shared with customers.

TQM

In June 2009, the NEB approved TQM's final tolls for 2007 and 2008, consisting of a 6.4 per cent after-tax weighted average cost of capital as authorized by the NEB in its RH-1-2008 Decision released in March 2009. This decision equates to a 9.85 per cent return on 40 per cent deemed common equity in 2007 and a 9.75 per cent return on 40 per cent deemed common equity in 2008. The decision granted TQM an aggregate return on capital and did not specify capital structure. Prior to this decision, TQM was subject to the NEB ROE formula on deemed common equity of 30 per cent. TQM's 2009 tolls remain in effect on an interim basis pending resolution of its cost of capital.

U.S. Regulated Operations

TCPL's U.S. natural gas pipelines are 'natural gas companies' operating under the provisions of the *Natural Gas Act of 1938,* the *Natural Gas Policy Act of 1978* and the *Energy Policy Act of 2005*, 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.

ANR

ANR's operations are regulated primarily by the FERC. ANR's natural gas storage and transportation services regulated by the FERC also operate under approved tariff rates. ANR Pipeline Company's rates were established pursuant to a settlement approved by a FERC order issued in 1998. These tariffs include maximum and minimum rate levels for services and permit ANR to discount or negotiate rates on a non-discriminatory basis. ANR Storage Company's rates were established pursuant to a settlement approved by the FERC in 1990. None of ANR's FERC-regulated operations are currently required to file for new rates at any time in the future, nor are any of the operations prohibited from filing a case for new rates.

GTN

GTN is regulated by the FERC and operates in accordance with FERC-approved tariffs that establish maximum and minimum rates for various services. GTN is permitted to discount or negotiate these rates on a non-discriminatory basis. In November 2007, GTN and its customers reached a rate case settlement that was approved by the FERC in January 2008. The settlement had an effective date of January 1, 2007, and established the rates currently in effect. Under the settlement, a five-year moratorium was established, during which GTN and the settling parties are prohibited from taking certain actions under the *Natural Gas Act of 1938*, including any rate adjustment filings. The settlement requires GTN to file a rate case within seven years of the effective date.

Great Lakes

In November 2009, the FERC initiated an investigation to determine whether Great Lakes' rates are just and reasonable. In response, Great Lakes filed a cost and revenue study with the FERC on February 4, 2010. A hearing is scheduled to commence on August 2, 2010, and an Initial Decision is required in November 2010. The impact of the investigation on Great Lakes' rates and revenues is unknown at this time.

Portland

In April 2008, Portland filed a general rate case with the FERC proposing a rate increase of approximately six per cent as well as other changes to its tariff. In May 2009, Portland reached a settlement with its customers on certain short-term issues in its rate case. The partial settlement has since been filed with the FERC and a final decision approving this partial settlement is expected in 2010. The remaining issues were litigated and Portland received the Initial Decision from the Administrative Law Judge in December 2009. Participants in the rate case now have an opportunity to respond to the Initial Decision. The FERC is expected to issue its final decision on the litigated portion of the rate case in fourth quarter 2010.

Northern Border

Northern Border and its customers reached a settlement in September 2006 that was approved by the FERC in November 2006. The settlement established maximum long-term mileage-based rates and charges for transportation on Northern Border's system. It provided for seasonal rates, which vary on a monthly basis, for short-term transportation services. It also included a three year moratorium on filing rate cases and on participants filing challenges to rates, and required Northern Border to file a general rate case within six years. Northern Border is required to provide services under negotiated and discounted rates on a non-discriminatory basis.

Regulatory Assets and Liabilities

Year ended December 31 (millions of dollars)	**2009**	2008	Remaining Recovery/ Settlement Period
			(years)
Regulatory Assets			
Future income taxes[(1)(2)]	**1,305**	n/a	n/a
Operating and debt-service regulatory assets[(3)]	**221**		1
Unrealized losses on derivatives[(4)]	**99**	67	1 - 4
Foreign exchange on long-term debt principal[(5)]	**30**	32	20
Future income tax on AFUDC[(6)]	**23**	26	n/a
Unamortized issue costs on Preferred Securities[(7)]	**17**	18	17
Phase II preliminary expenditures[(2)(8)]	**14**	16	6
Transitional other benefit obligations[(2)(9)]	**13**	15	7
Unamortized post-retirement benefits[(10)]	**6**	11	2
Other	**17**	16	n/a
	1,745	201	
Less: Current portion included in Other Current Assets	**221**		
	1,524	201	
Regulatory Liabilities			
Foreign exchange on long-term debt[(11)]	**218**	70	1-20
Foreign exchange gain on redemption of Preferred Securities[(7)]	**68**	101	2
Post-retirement benefits other than pension[(12)]	**59**	58	n/a
Operating and debt-service regulatory liabilities[(3)]	**31**	234	1
Negative salvage[(13)]	**37**	39	n/a
Unamortized gains on derivatives[(4)]		24	n/a
Fuel tracker[(14)]		23	1
Other	**3**	2	n/a
	416	551	
Less: Current portion included in Accounts Payable	**31**	234	
	385	317	

(1) Effective January 1, 2009, CICA Handbook Section 3465 "Income Taxes" was amended to require the recognition of future income tax assets and liabilities for rate-regulated operations. The Company chose to adopt accounting policies consistent with FASB's ASC Topic 980 "Regulated Operations". As a result, TCPL is required to recognize future income tax assets and liabilities, instead of using the taxes payable method. An offsetting adjustment is recorded to regulatory assets and liabilities. As a result of adopting this accounting change, additional future income tax liabilities and a regulatory asset in the amount of $1,305 million were recorded at December 31, 2009 in each of Future Income Taxes and Regulatory Assets, respectively. There was no effect on Net Income as a result of this change.

(2)

These regulatory assets are either underpinned by non-cash transactions or are recovered without an allowance for return as approved by the regulator. Accordingly, these regulatory assets are not included in rate base and do not yield a return on investment during the recovery period.

(3) Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances approved by the regulatory authority for inclusion in determining tolls for the following calendar year. Pre-tax operating results would have been $424 million lower in 2009 (2008 $316 million higher) if these amounts had not been recorded as regulatory assets and liabilities.

(4) Unrealized gains and losses on derivatives represent the net position of fair value gains and losses on cross-currency and interest-rate swaps, and forward foreign currency contracts, which act as economic hedges. The cross-currency swaps pertain to foreign debt instruments associated with the Canadian Mainline, Alberta System and Foothills. Pre-tax operating results would have been $56 million lower in 2009 (2008 $63 million higher) if these amounts had not been recorded as regulatory assets and liabilities.

(5) The foreign exchange on long-term debt principal amount in the Alberta System, as approved by the AUC in 2008 and the NEB in 2009, is designed to facilitate the recovery or refund of foreign exchange gains and losses over the life of the foreign currency debt issues. Realized gains and losses and estimated net future losses on foreign currency debt are 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. Pre-tax operating results would have been $2 million higher in 2009 and 2008 if these amounts had not been recorded as regulatory assets.

(6) Rate-regulated accounting allows the capitalization of both equity and interest components of AFUDC. The capitalized AFUDC is depreciated as part of the total depreciable plant after the utility assets are placed in service. Equity AFUDC is not subject to income taxes, therefore, a future income tax provision is recorded with an offset to a corresponding regulatory asset.

(7) In July 2007, the Company redeemed the US$460 million 8.25 per cent Preferred Securities that underpinned the Canadian Mainline's investment base. Upon redemption of the securities, a foreign exchange gain was realized that will flow through, net of income tax, to Canadian Mainline's customers over the five years of the current tolls settlement. In addition, the issue costs on the Preferred Securities will be amortized over 20 years beginning January 1, 2007. At December 31, 2009, the unamortized amount of $68 million (2008 $101 million) is net of income taxes of $6 million (2008 $10 million). If these amounts had not been recorded as a regulatory liability, pre-tax operating results would have been $37 million lower in 2009 (2008 $53 million lower).

(8) Phase II preliminary expenditures are costs incurred by Foothills prior to 1981 related to development of Canadian facilities to deliver Alaskan gas. These costs have been approved by the regulator for collection through straight-line amortization over the period November 2002 to December 2015. Pre-tax operating results would have been $2 million higher in 2009 and 2008 if these amounts had not been recorded as regulatory assets.

(9) The regulatory asset with respect to the annual transitional other benefit obligations is being amortized over 17 years to December 2016, at which time the full transitional obligation will have been recovered through tolls. Pre-tax operating results would have been $2 million higher in 2009 (2008 $1 million higher) if these amounts had not been recorded as regulatory assets.

(10) An amount is recovered in ANR's rates for post-retirement benefits other than pensions (PBOP). A curtailment and special termination benefits charge related to PBOP for a closed group of retirees was recorded as a regulatory asset and is being amortized through 2011. Pre-tax operating results would have been $5 million higher in 2009 (2008 $3 million higher) if these amounts had not been recorded as regulatory assets.

(11) Foreign exchange on long-term debt of the Canadian Mainline, Alberta System and Foothills represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historical foreign exchange rate. Foreign exchange gains and losses realized when foreign debt matures or is redeemed early are expected to be recovered or refunded through the determination of future tolls. In the absence of rate-regulated accounting, GAAP would have required the inclusion of these unrealized gains or losses 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.

(12) An amount is recovered in ANR's rates for PBOP. This regulatory liability represents the difference between the amount collected in rates and the amount of PBOP expense. The PBOP expense recorded in 2009 was $1 million (2008 nil).

(13) Negative salvage is recovered in rates for certain regulated facilities. These amounts are recorded as a regulatory liability. Costs associated with the abandonment of these facilities will reduce this regulatory liability when they are paid.

(14) ANR's tariff stipulates a fuel tracker mechanism to track over-or under-collections of fuel used and natural gas lost and unaccounted for (collectively, fuel). The fuel tracker represents the difference between the value of 'in-kind' natural gas retained from shippers and the actual amount of natural gas used for fuel by ANR. Any over-or under-collections are returned to or collected from shippers through a prospective annual adjustment to fuel retention rates. A regulatory asset or liability is established for the difference between ANR's actual fuel use and amounts collected through its fuel rates. Pre-tax operating results are not affected by the fuel tracker mechanism.

NOTE 15 NON-CONTROLLING INTERESTS

The Company's non-controlling interests included in the Consolidated Balance Sheet were as follows:

December 31 (millions of dollars)	**2009**	2008
Non-controlling interest in PipeLines LP[(1)]	**705**	721
Non-controlling interest in Portland	**80**	84
	785	805

The Company's non-controlling interests included in the Consolidated Income Statement were as follows:

Year ended December 31 (millions of dollars)	**2009**	2008	2007
Non-controlling interest in PipeLines LP[(1)]	**66**	62	65
Non-controlling interest in Portland	**8**	46	10
	74	108	75

(1) Effective November 18, 2009, the non-controlling interests in PipeLines LP was 61.8 per cent. From July 1, 2009 to November 17, 2009, the non-controlling interests in PipeLines LP was 57.4 per cent. From February 22, 2007 to June 30, 2009, the non-controlling interests in PipeLines LP was 67.9 per cent.

The non-controlling interests in PipeLines LP and Portland as at December 31, 2009 represented the 61.8 per cent and 38.3 per cent interest, respectively, not owned by TCPL (2008 and 2007 67.9 per cent and 38.3 per cent, respectively).

TCPL received fees of $2 million from PipeLines LP in 2009 (2008 and 2007 $2 million) and $8 million from Portland in 2009 (2008 and 2007 $7 million) for services it provided.

NOTE 16 COMMON SHARES

	Number of Shares	Amount
	(thousands)	(millions of dollars)
Outstanding at January 1, 2007	483,344	4,712
Issuance of common shares	48,205	1,842
Outstanding at December 31, 2007	531,549	6,554
Issuance of common shares	66,341	2,419
Outstanding at December 31, 2008	597,890	8,973
Issuance of common shares	**51,536**	**1,676**
Outstanding at December 31, 2009	**649,426**	**10,649**

Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares without par value.

Share Capital

In 2009, TCPL issued 51.5 million (2008 66.3 million; 2007 48.2 million) common shares to TransCanada for proceeds of approximately $1.7 billion (2008 $2.4 billion; 2007 $1.8 billion).

Restriction on Dividends

Certain terms of the Company's preferred shares and debt instruments could restrict the Company's ability to declare dividends on preferred and common shares. At December 31, 2009, approximately $2.6 billion (2008 $1.7 billion; 2007 $1.5 billion) was available for the payment of dividends on common and preferred shares.

Cash Dividends

Cash dividends of $976 million were paid in 2009 (2008 $795 million; 2007 $703 million).

NOTE 17 PREFERRED SHARES

December 31	Number of Shares	Dividend Rate Per Share	Redemption Price Per Share	**2009**	2008
	(thousands)			(millions of dollars)	(millions of dollars)
Cumulative First Preferred Shares					
Series U	4,000	$2.80	$50.00	**195**	195
Series Y	4,000	$2.80	$50.00	**194**	194
				389	389

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

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

Dividend Reinvestment and Share Purchase Plan

TransCanada's Board of Directors authorized the issuance of common shares from treasury at a discount to participants in TransCanada's Dividend Reinvestment and Share Purchase Plan (DRP). Under the DRP, eligible TCPL preferred shareholders may reinvest their dividends and make optional cash payments to obtain TransCanada common shares. The discount was set at two per cent commencing with the dividend payable in April 2007 and was increased to three per cent with the dividend payable in January 2009. Prior to the April 2007 dividend, TransCanada purchased shares on the open market and provided them to DRP participants at cost. TransCanada reserves the right to alter the discount or return to purchasing shares on the open market at any time.

Cash Dividends

Cash dividends of $22 million or $2.80 per share were paid on the Series U and Series Y preferred shares in 2009, 2008 and 2007.

NOTE 18 RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TCPL has exposure to market risk, counterparty credit risk and liquidity risk. TCPL engages in risk management activities with the objective being to protect earnings, cash flow and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure TCPL's risks and related exposures are in line with the Company's business objectives and risk tolerance. Risks are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by risk management and internal audit personnel. The Board of Directors' Audit Committee oversees how management monitors compliance with risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework. Internal audit personnel assist the Audit Committee in its oversight role by performing regular and ad-hoc reviews of risk management controls and procedures, the results of which are reported to the Audit Committee.

Market Risk

The Company constructs and invests in large infrastructure projects, purchases and sells energy commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. These activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which affect the Company's earnings and the value of the financial instruments it holds.

The Company uses derivatives as part of its overall risk management strategy to manage the exposure to market risk that results from these activities. Derivative contracts used to manage market risk generally consist of the following:

- Forwards and futures contracts contractual agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future. TCPL enters into foreign exchange and commodity forwards and futures to mitigate the impact of volatility in foreign exchange rates and commodity prices.

- Swaps contractual agreements between two parties to exchange streams of payments over time according to specified terms. The Company enters into interest rate, cross-currency and commodity swaps to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.

- Options contractual agreements to convey the right, but not the obligation, of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. The Company enters into option agreements to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.

Commodity Price Risk

The Company is exposed to commodity price movements as part of its normal business operations, particularly in relation to the prices of electricity, natural gas and oil products. A number of strategies are used to mitigate these exposures, including the following:

- Subject to its overall risk management strategy, the Company commits a significant portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to mitigate price risk in its asset portfolio.

- The Company purchases a portion of the natural gas and oil products required for its power plants or enters into contracts that base the sales price of electricity on the cost of natural gas, effectively locking in a margin. A significant portion of the electricity needed to fulfill the Company's power sales commitments is fulfilled through power generation or purchased through contracts, thereby reducing the Company's exposure to fluctuating commodity prices.

- The Company enters into offsetting or back-to-back positions using derivative financial instruments to manage price risk exposure in power and natural gas commodities created by certain fixed and variable pricing arrangements for different pricing indices and delivery points.

The Company assesses its commodity contracts and derivative instruments used to manage commodity risk to determine the appropriate accounting treatment. Contracts, with the exception of leases, have been assessed to determine whether they or certain aspects of them meet the definition of a derivative. Certain commodity purchase and sale contracts are derivatives but are not within the scope of the CICA Handbook Section 3855 "Financial Instruments Recognition and Measurement", as they were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's expected purchase, sale or usage requirements. Certain other contracts are not within the scope of Section 3855 as they are considered to meet other exemptions.

TCPL manages its exposure to seasonal natural gas price spreads in its natural gas storage business by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. TCPL simultaneously enters into a forward purchase of natural gas for injection into storage and an offsetting forward sale of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to natural gas price movements. Fair value adjustments recorded each period on proprietary natural gas inventory in storage and these forward contracts may not be representative of the amounts that will be realized on settlement.

Natural Gas Inventory Price Risk

At December 31, 2009, the fair value of proprietary natural gas inventory in storage, as measured using a weighted average of forward prices for the following four months less selling costs, was $73 million (2008 $76 million). The change in fair value of proprietary natural gas inventory in storage in 2009 resulted in a net pre-tax unrealized gain of $3 million (2008 unrealized loss of $7 million; 2007 nil), which was recorded as an increase to Revenues and Inventories. The net change in fair value of natural gas forward purchase and sales contracts in 2009 resulted in a net pre-tax unrealized loss of $2 million (2008 unrealized gain of $7 million; 2007 unrealized gain of $10 million), which was recorded as a decrease in Revenues.

Foreign Exchange and Interest Rate Risk

Foreign exchange and interest rate risk is created by fluctuations in the fair value or cash flow of financial instruments due to changes in foreign exchange rates and market interest rates.

A portion of TCPL's earnings from its Pipelines and Energy segments is generated in U.S. dollars and, as such, movement of the Canadian dollar relative to the U.S. dollar can affect TCPL's earnings. This foreign exchange impact is offset by certain related debt and financing costs being denominated in U.S. dollars and by the Company's hedging activities. TCPL has a greater exposure to U.S. currency fluctuations than in prior years due to growth in its U.S. operations, partially offset by increased levels of U.S. dollar-denominated debt.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to its debt and other U.S. dollar-denominated transactions, and to manage the interest rate exposures of the Canadian Mainline, Alberta System and Foothills operations. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms. These gains and losses are deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers in accordance with the terms of the shipping agreements.

TCPL has floating interest rate debt, which subjects it to interest rate cash flow risk. The Company uses a combination of interest rate swaps and options to manage its exposure to this risk.

On a consolidated basis, the impact of changes in the U.S. dollar on U.S. Pipelines and Energy earnings is largely offset by the impact on U.S. dollar interest expense. The resultant net exposure is managed using derivatives, effectively reducing the Company's exposure to changes in foreign exchange rates.

Net Investment in Self-Sustaining Foreign Operations

The Company hedges its net investment in self-sustaining foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, forward foreign exchange contracts and foreign exchange options. At December 31, 2009, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $7.9 billion (US$7.6 billion) (2008 $7.2 billion (US$5.9 billion)) and a fair value of $9.8 billion (US$9.3 billion) (2008 $5.9 billion (US$4.8 billion)). At December 31, 2009, $96 million was included in Intangibles and Other Assets (2008 $254 million in Deferred Amounts) for the fair value of the forwards, swaps and options used to hedge the Company's net U.S. dollar investment in foreign operations. The fair values and notional or principal amounts for the derivatives designated as a net investment hedge were as follows:

Asset/(Liability) *December 31 (millions of dollars)*	**2009** **Fair Value**[1]	 **Notional or Principal Amount**	2008 Fair Value[1]	 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2010 to 2014)	**86**	**U.S. 1,850**	(218)	U.S. 1,650
U.S. dollar forward foreign exchange contracts (maturing 2010)	**9**	**U.S. 765**	(42)	U.S. 2,152
U.S. dollar options (maturing 2010)	**1**	**U.S. 100**	6	U.S. 300
	96	**U.S. 2,715**	(254)	U.S. 4,102

(1) Fair values equal carrying values.

VaR Analysis

TCPL uses a Value-at-Risk (VaR) methodology to estimate the potential impact resulting from its exposure to market risk on its open liquid positions. VaR estimates the potential change in pre-tax earnings over a given holding period for a specified confidence level. The VaR number calculated and used by TCPL reflects a 95 per cent probability that the daily change resulting from normal market fluctuations in its open liquid positions will not exceed the reported VaR. The VaR methodology is a statistically-calculated, probability-based approach that takes into consideration market volatilities as well as risk diversification by recognizing offsetting positions and correlations among products and markets. Risks are measured across all products and markets, and risk measures are aggregated to arrive at a single VaR number.

There is currently no uniform industry methodology for estimating VaR. The use of VaR has limitations because it is based on historical correlations and volatilities in commodity prices, interest rates and foreign exchange rates, and assumes that future price movements will follow a statistical distribution. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR.

TCPL's estimation of VaR includes wholly owned subsidiaries and incorporates relevant risks associated with each market or business unit. The calculation does not include the Pipelines segment as the rate-regulated nature of the pipeline business reduces the impact of market risks. TCPL's Board of Directors has established a VaR limit, which is monitored on an ongoing basis as part of the Company's risk management policy. TCPL's consolidated VaR was $12 million at December 31, 2009 (2008 $23 million). The decline from December 31, 2008 was primarily due to decreased prices and lower open positions in the U.S. power portfolio.

Counterparty Credit Risk

Counterparty credit risk represents the financial loss the Company would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of its contracts with the Company.

Counterparty credit risk is managed through established credit management techniques, including conducting financial and other assessments to establish and monitor a counterparty's creditworthiness, setting exposure limits, monitoring exposures against these limits, using master netting arrangements and obtaining financial assurances where warranted. In general, financial assurances include guarantees, letters of credit and cash. The Company monitors and manages its concentration of counterparty credit risk on an ongoing basis. The Company believes these measures minimize its counterparty credit risk but there is no certainty that they will protect it against all material losses.

TCPL's maximum counterparty credit exposure with respect to financial instruments at the balance sheet date consisted primarily of non-derivative financial assets such as accounts receivable, loans and notes receivable, as well as the fair value of derivative assets. Within these balances, the Company does not have significant concentrations of counterparty credit risk with any individual counterparties and the majority of counterparty credit exposure is with counterparties who are investment grade. At December 31, 2009, there were no significant amounts past due or impaired.

TCPL has significant credit and performance exposures to financial institutions as they provide committed credit lines and cash deposit facilities, critical liquidity in the foreign exchange derivative, interest rate derivative and energy wholesale markets, and letters of credit to mitigate TCPL's exposure to non-creditworthy counterparties.

As a level of uncertainty continues to exist in the global financial markets, TCPL continues to closely monitor and reassess the creditworthiness of its counterparties. This has resulted in TCPL reducing or mitigating its exposure to certain counterparties where it was deemed warranted and permitted under contractual terms. As part of its ongoing operations, TCPL must balance its market and counterparty credit risks when making business decisions.

Certain subsidiaries of Calpine Corporation (Calpine) filed for bankruptcy protection in both Canada and the U.S. in 2005. Gas Transmission Northwest Corporation (GTNC) and Portland reached agreements with Calpine for allowed unsecured claims in the Calpine bankruptcy. In February 2008, GTNC and Portland received initial distributions of 9.4 million common shares and 6.1 million common shares, respectively, of Calpine, which represented approximately 85 per cent of their agreed-upon claims. In 2008, these shares were sold into the open market and resulted in total pre-tax gains of $279 million. Claims by NGTL and Foothills Pipe Lines (South B.C.) Ltd. for $32 million and $44 million, respectively, were received in cash in January 2008 and were passed on to shippers on these systems in 2008 and 2009.

Liquidity Risk

Liquidity risk is the risk that TCPL will not be able to meet its financial obligations when due. The Company's approach to managing liquidity risk is to ensure that, under both normal and stressed conditions, it always has sufficient cash and credit facilities to meet its obligations when due without incurring unacceptable losses or damage to the Company's reputation.

Management continuously forecasts cash flows for a period of 12 months to identify financing requirements. These requirements are then managed through a combination of committed and demand credit facilities and access to capital markets, as discussed under the heading Capital Management below.

At December 31, 2009, the Company had committed revolving bank lines of US$1.0 billion, $2.0 billion, US$1.0 billion and US$300 million maturing November 2010, December 2012, December 2012 and February 2013, respectively. At December 31, 2009, the US$300 million facility was fully drawn and no draws were made on any of the other facilities. The Company has maintained continuous access to the Canadian commercial paper market on competitive terms.

The Company has access to capital markets under the following prospectuses:

- In December 2009, TCPL filed a US$4.0 billion debt base shelf prospectus qualifying for the issuance of up to US$4.0 billion of debt securities in the U.S. At December 31, 2009, no amounts were issued under the base shelf prospectus.

- In April 2009, TCPL filed a $2.0 billion Medium-Term Notes base shelf prospectus in Canada. At December 31, 2009, no amounts were issued under this base shelf prospectus.

Capital Management

The primary objective of capital management is to ensure TCPL has strong credit ratings to support its businesses and maximize shareholder value. In 2009, the overall objective and policy for managing capital remained unchanged from the prior year.

TCPL manages its capital structure in a manner consistent with the risk characteristics of the underlying assets. The Company's management considers its capital structure to consist of net debt, Non-Controlling Interests and Shareholders' Equity. Net debt is comprised of Notes Payable, net amounts Due to TransCanada Corporation, Long-Term Debt and Junior Subordinated Notes less Cash and Cash Equivalents. Net

debt only includes obligations that the Company controls and manages. Consequently, it does not include Cash and Cash Equivalents, Notes Payable and Long-Term Debt of TCPL's joint ventures.

The capital structure was as follows:

December 31 (millions of dollars)	**2009**	2008
Notes payable	**1,678**	1,685
Due to TransCanada, net	**1,224**	292
Long-term debt	**16,664**	16,154
Junior subordinated notes	**1,036**	1,213
Cash and cash equivalents	**(878)**	(1,109)
Net debt	**19,724**	18,235
Non-controlling interests	**785**	805
Shareholders' equity	**14,872**	12,963
Total equity	**15,657**	13,768
Total capital	**35,381**	32,003

Fair Values

Certain financial instruments included in Cash and Cash Equivalents, Accounts Receivable, Intangibles and Other Assets, Due to/from TransCanada Corporation, Notes Payable, Accounts Payable, Accrued Interest and Deferred Amounts have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity. 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 oil products derivatives has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques are used. Credit risk has been taken into consideration when calculating the fair value of derivatives.

The fair value of the Company's Long-Term Debt was estimated based on quoted market prices for the same or similar debt instruments and, when such information was not available, was estimated by discounting future payments of interest and principal at estimated interest rates that were made available to the Company.

Non-Derivative Financial Instruments Summary

The carrying and fair values of non-derivative financial instruments were as follows:

	2009		**2008**	
December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial Assets(1)				
Cash and cash equivalents	**979**	**979**	1,300	1,300
Accounts receivable and intangibles and other assets(2)(3)	**1,433**	**1,484**	1,427	1,427
Due from TransCanada Corporation	**845**	**845**	1,329	1,329
Available-for-sale assets(2)	**23**	**23**	27	27
	3,280	**3,331**	4,083	4,083
Financial Liabilities(1)(3)				
Notes payable	**1,687**	**1,687**	1,702	1,702
Accounts payable and deferred amounts(4)	**1,532**	**1,532**	1,364	1,364
Due to TransCanada Corporation	**2,069**	**2,069**	1,621	1,621
Accrued interest	**380**	**380**	361	361

	2009		2008	
Long-term debt	**16,664**	**19,377**	16,154	15,337
Junior subordinated notes	**1,036**	**976**	1,213	815
Long-term debt of joint ventures	**965**	**1,025**	1,076	1,052
	24,333	**27,046**	23,491	22,252

(1) Consolidated Net Income in 2009 included $6 million (2008 $15 million) for fair value adjustments related to interest rate swap agreements on US$250 million (2008 US$200 million and $50 million) of long-term debt. There were no other unrealized gains or losses from fair value adjustments to these financial instruments.

(2) At December 31, 2009, the Consolidated Balance Sheet included financial assets of $968 million (2008 $1,280 million) in Accounts Receivable and $488 million (2008 $174 million) in Intangibles and Other Assets.

(3) Recorded at amortized cost except for certain Long-Term Debt and Notes Receivable which are adjusted to fair value.

(4) At December 31, 2009, the Consolidated Balance Sheet included financial liabilities of $1,507 million (2008 $1,342 million) in Accounts Payable and $25 million (2008 $22 million) in Deferred Amounts.

The following tables detail the remaining contractual maturities for TCPL's non-derivative financial liabilities, including both the principal and interest cash flows at December 31, 2009:

Contractual Repayments of Financial Liabilities[1]

		Payments Due by Period			
(millions of dollars)	Total	2010	2011 and 2012	2013 and 2014	2015 and Thereafter
Notes payable	1,687	1,687			
Due to TransCanada Corporation	2,069		2,069		
Long-term debt and junior subordinated notes	17,700	478	2,099	1,879	13,244
Long-term debt of joint ventures	965	212	174	94	485
	22,421	2,377	4,342	1,973	13,729

(1) The anticipated timing of settlement of derivative contracts is presented in the Derivatives Financial Instrument Summary in this note.

Interest Payments on Financial Liabilities

		Payments Due by Period			
(millions of dollars)	Total	2010	2011 and 2012	2013 and 2014	2015 and Thereafter
Due to TransCanada Corporation	79	26	53		
Long-term debt and junior subordinated notes	17,123	1,186	2,260	2,093	11,584
Long-term debt of joint ventures	305	46	73	65	121
	17,507	1,258	2,386	2,158	11,705

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2009 is as follows:

	2009				
December 31 (all amounts in millions unless otherwise indicated)	**Power**	**Natural Gas**	**Oil Products**	**Foreign Exchange**	**Interest**
Derivative Financial Instruments Held for Trading[1]					
Fair Values[2]					
Assets	**$150**	**$107**	**$5**	**$**	**$25**
Liabilities	**$(98)**	**$(112)**	**$(5)**	**$(66)**	**$(68)**
Notional Values					
Volumes[3]					
Purchases	**15,275**	**238**	**180**		
Sales	**13,185**	**194**	**180**		
Canadian dollars					**574**
U.S. dollars				**U.S. 444**	**U.S. 1,325**
Cross-currency				**227/U.S. 157**	
Net unrealized gains/(losses) in the year	**$3**	**$(5)**	**$1**	**$3**	**$27**
Net realized gains/(losses) in the year	**$70**	**$(76)**	**$**	**$36**	**(22)**
Maturity dates	**2010 - 2015**	**2010 - 2014**	**2010**	**2010 - 2012**	**2010 - 2018**
Derivative Financial Instruments in Hedging Relationships[4][5]					
Fair Values[2]					
Assets	**$175**	**$2**	**$**	**$**	**$15**
Liabilities	**$(148)**	**$(22)**	**$**	**$(43)**	**$(50)**
Notional Values					
Volumes[3]					
Purchases	**13,641**	**33**			
Sales	**14,311**				
U.S. dollars				**U.S. 120**	**U.S. 1,825**
Cross-currency				**136/U.S. 100**	
Net realized gains/(losses) in the year	**$156**	**$(29)**	**$**	**$**	**$(37)**
Maturity dates	**2010 - 2015**	**2010 - 2014**		**2010 - 2014**	**2010 - 2020**

(1) All derivative financial instruments in the held-for-trading classification have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

(2) Fair values equal carrying values.

(3) Volumes for power, natural gas and oil products derivatives are in GWh, billion cubic feet (Bcf) and thousands of barrels, respectively.

(4) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $4 million and a notional amount of US$150 million. Net realized gains on fair value hedges for December 31, 2009 were $4 million and were included in Interest Expense. In 2009, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(5) In 2009, Net Income included losses of $5 million for the changes in fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2009, there were no gains or losses included in Net Income for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

The anticipated timing of settlement of the derivative contracts assumes constant commodity prices, interest rates and foreign exchange rates from December 31, 2009. Settlements will vary based on the actual value of these factors at the date of settlement. The anticipated timing of settlement of these contracts is as follows:

Year ended December 31 *(millions of dollars)*	Total	2010	2011 and 2012	2013 and 2014	2015 and Thereafter
Derivative financial instruments held for trading					
Assets	287	201	73	11	2
Liabilities	(349)	(233)	(85)	(27)	(4)
Derivative financial instruments in hedging relationships					
Assets	288	142	106	35	5
Liabilities	(263)	(106)	(89)	(66)	(2)
	(37)	4	5	(47)	1

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2008 is as follows:

	2008				
December 31 *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Oil Products	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading					
Fair Values(1)					
Assets	$132	$144	$10	$41	$57
Liabilities	$(82)	$(150)	$(10)	$(55)	$(117)
Notional Values					
Volumes(2)					
Purchases	4,035	172	410		
Sales	5,491	162	252		
Canadian dollars					1,016
U.S. dollars				U.S. 479	U.S. 1,575
Japanese yen (in billions)				JPY 4.3	
Cross-currency				227/U.S. 157	
Net unrealized gains/(losses) in the year	$24	$(23)	$1	$(9)	$(61)
Net realized gains/(losses) in the year	$23	$(2)	$1	$6	$13
Maturity dates	2009 - 2014	2009 - 2011	2009	2009 - 2012	2009 - 2018
Derivative Financial Instruments in Hedging Relationships(3)(4)					
Fair Values(1)					
Assets	$115	$	$	$2	$8
Liabilities	$(160)	$(18)	$	$(24)	$(122)
Notional Values					
Volumes(2)					
Purchases	8,926	9			
Sales	13,113				
Canadian dollars					50
U.S. dollars				U.S. 15	U.S. 1,475
Cross-currency				136/U.S. 100	
Net realized (losses)/gains in the year	$(56)	$15	$	$	$(10)
Maturity dates	2009 - 2014	2009 - 2011		2009 - 2013	2009 - 2019

(1) Fair values equal carrying value.

(2) Volumes for power, natural gas and oil products derivatives are in GWh, Bcf and thousands of barrels, respectively.

(3) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $8 million and notional amounts of $50 million and US$50 million. Net realized gains on fair value hedges at December 31, 2008 were $1 million. In 2008, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(4) In 2008, Net Income included losses of $6 million for changes in fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2008, there were no gains or losses included in Net Income for discontinued cash flow hedges.

Balance Sheet Presentation of Derivative Financial Instruments

The fair value of the derivative financial instruments in the Company's Balance Sheet was as follows:

December 31 (millions of dollars)	**2009**	2008
Current		
Other current assets	**315**	318
Accounts payable	**(340)**	(298)
Long-term		
Intangibles and other assets	**260**	191
Deferred amounts	**(272)**	(694)

Derivative Financial Instruments of Joint Ventures

Included in the Balance Sheet Presentation of Derivative Financial Instruments summary are amounts related to power derivatives used by one of the Company's joint ventures to manage commodity price risk. The Company's proportionate share of the fair value of these power sales derivatives was $105 million at December 31, 2009 (2008 $75 million). These contracts mature from 2010 to 2015. The Company's proportionate share of the notional sales volumes of power associated with this exposure was 6,312 gigawatt hours (GWh) at December 31, 2009 (2008 7,600 GWh). The Company's proportionate share of the notional purchased volumes of power associated with this exposure was 2,747 GWh at December 31, 2009 (2008 47 GWh).

Fair Value Hierarchy

The Company's financial assets and liabilities recorded at fair value have been categorized into three categories based upon a fair value hierarchy. Fair value of assets and liabilities included in Level I is determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level II include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. This category includes fair value determined using valuation techniques, such as option pricing models and extrapolation using observable inputs. Level III valuations are based on inputs that are not readily observable and are significant to the overall fair value measurement. Long-dated commodity transactions in certain markets and the fair value of guarantees are included in this category. Long-dated commodity prices are derived with a third party modelling tool that uses market fundamentals to derive long-term prices. The fair value of guarantees is estimated by discounting the cash flows that would be incurred if letters of credit were used in place of the guarantees.

Assets and liabilities measured at fair value as of December 31, 2009, including both current and non-current portions, are categorized as follows. There were no transfers between Level I and Level II in 2009.

(millions of dollars, pre-tax)	Quoted Prices in Active Markets (Level I)	Significant Other Observable Inputs (Level II)	Significant Unobservable Inputs (Level III)	Total
Natural Gas Inventory		73		73
Derivative Financial Instruments:				
Assets	65	509	14	588
Liabilities	(109)	(500)	(16)	(625)
Non-Derivative Financial Instruments: Available-for-sale assets	23			23
Guarantee Liabilities[1]			(4)	(4)
	(21)	82	(6)	55

(1) The fair value of guarantees is included in Deferred Amounts as at December 31, 2009.

The following table presents the net change in assets and liabilities measured at fair value and included in the Level III fair value category:

(millions of dollars, pre-tax)	Derivatives[(1)]	Guarantees[(2)]	Total
Balance at December 31, 2008		(9)	(9)
New contracts[(3)]	**(14)**		**(14)**
Transfers into Level III[(4)]	**12**		**12**
Total realized and unrealized gains/(losses) included in Deferred Amounts		**(7)**	**(7)**
Other		**7**	**7**
Balance at December 31, 2009	**(2)**	**(9)**	**(11)**

(1) The fair value of derivative assets and liabilities is presented on a net basis.

(2) The fair value of guarantees is recognized in Deferred Amounts. No amounts were recognized in earnings for the periods presented.

(3) The total amount of net gains included in earnings attributable to derivatives that were entered into during the period and still held at the reporting date is nil for the year ended December 31, 2009.

(4) These contracts were previously included in Level II but were reclassified to Level III due to reduced liquidity in the market to which they relate.

A 10 per cent increase or 10 per cent decrease in commodity prices, with all other variables held constant, would cause an $18 million decrease or an $18 million increase, respectively, in the fair value of derivative financial instruments outstanding as at December 31, 2009.

A 100 basis points increase or 100 basis points decrease in the letter of credit rate, with all other variables held constant, would cause a $6 million increase or a $6 million decrease, respectively, in the fair value of guarantee liabilities outstanding as at December 31, 2009. Similarly, the effect of a 100 basis points increase or 100 basis points decrease in the discount rate on the fair value of guarantee liabilities outstanding as at December 31, 2009 would cause a $2 million decrease in the liability or a $2 million increase in the liability, respectively.

NOTE 19 INCOME TAXES

Provision for Income Taxes

Year ended December 31 (millions of dollars)	**2009**	2008	2007
Current			
Canada	**(68)**	381	364
Foreign	**100**	143	65
	32	524	429
Future			
Canada	**326**	(10)	8
Foreign	**18**	77	46
	344	67	54
	376	591	483

Geographic Components of Income

Year ended December 31 (millions of dollars)	**2009**	2008	2007
Canada	**1,061**	1,203	1,208
Foreign	**768**	938	582

Income before Income Taxes and Non-Controlling Interests	**1,829**	2,141	1,790

Reconciliation of Income Tax Expense

Year ended December 31 (millions of dollars)	**2009**	2008	2007
Income before income taxes and non-controlling interests	**1,829**	2,141	1,790
Federal and provincial statutory tax rate	**29.0%**	29.5%	32.1%
Expected income tax expense	**530**	632	575
Income tax differential related to regulated operations	**39**	44	69
Lower effective foreign tax rates	**(63)**	(5)	(39)
Tax rate and legislative changes	**(30)**		(73)
Income from equity investments and non-controlling interests	**(37)**	(45)	(34)
Change in valuation allowance		(9)	
Other[(1)]	**(63)**	(26)	(15)
Actual Income Tax Expense	**376**	591	483

(1) Includes net income tax benefits of $23 million recorded in 2009 (2008 $7 million; 2007 $13 million) on the resolution of certain income tax matters with taxation authorities as well as changes in estimates.

Future Income Tax Assets and Liabilities

December 31 (millions of dollars)	**2009**	2008
Deferred amounts	**42**	119
Other post-employment benefits	**72**	69
Unrealized losses on derivatives	**56**	62
Unrealized foreign exchange losses on long-term debt		77
Non-capital loss carryforwards	**148**	24
Other	**90**	107
	408	458
Less: valuation allowance[(1)]		77
Future income tax assets, net of valuation allowance	**408**	381
Difference in accounting and tax bases of plant, equipment and PPAs	**2,642**	1,464
Taxes on future revenue requirement	**338**	
Investments in subsidiaries and partnerships	**17**	28
Pension benefits	**75**	55
Unrealized foreign exchange gains on long-term debt	**96**	14
Unrealized gains on derivatives	**32**	19
Deferred credits	**57**	
Other	**44**	54
Future income tax liabilities	**3,301**	1,634
Net Future Income Tax Liabilities	**2,893**	1,253

(1) A valuation allowance was recorded in 2008 as there was no virtual certainty that the Company would realize the tax benefit related to the unrealized foreign exchange losses on long-term debt in the future.

Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. Future income tax liabilities would have increased by approximately $101 million at December 31, 2009 (2008 $102 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $83 million, net of refunds received were made in 2009 (2008 $486 million; 2007 $440 million).

NOTE 20 NOTES PAYABLE

	2009		2008	
	Outstanding December 31	**Weighted Average Interest Rate per Annum at December 31**	Outstanding December 31	Weighted Average Interest Rate per Annum at December 31
	(millions of dollars)		(millions of dollars)	
Canadian dollars	**327**	**0.3%**	1,250	1.8%
U.S. dollars (2009 US$1,299; 2008 US$369)	**1,360**	**0.4%**	452	3.3%
	1,687		1,702	

Notes payable consists of commercial paper outstanding and draws on bridge and line-of-credit facilities.

At December 31, 2009, total committed revolving and demand credit facilities of $5.2 billion were available. When 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. These unsecured credit facilities included the following:

A $2.0 billion committed, syndicated, revolving TCPL credit facility maturing December 2012. The facility was fully available at December 31, 2009. The cost to maintain the credit facility was $2 million in 2009 and 2008.

A US$300 million committed, syndicated revolving facility, guaranteed by TransCanada, maturing February 2013. This facility is part of the US$1.0 billion TCPL USA credit facility discussed in Note 10. At December 31, 2009, this facility was fully drawn. The cost to maintain the credit facility was $1 million in 2009 and 2008.

A US$1.0 billion committed, syndicated revolving TransCanada Keystone Pipeline, L.P. credit facility, guaranteed by TCPL, maturing November 2010 but extendible to November 2011 at the option of the borrower. The facility was fully available at December 31, 2009. The cost to maintain the credit facility was $2 million in 2009 (2008 nil).

A US$1.0 billion committed, syndicated revolving TCPL USA credit facility established in fourth quarter 2009, maturing December 2012 with a one year term extension at the option of the borrower. The facility is guaranteed by TransCanada and was fully available at December 31, 2009.

Demand lines totalling $805 million, which support the issuance of letters of credit and provide additional liquidity. The Company had used approximately $467 million of these demand lines for letters of credit at December 31, 2009.

In June 2008, TCPL executed an agreement with a syndicate of banks for a US$1.5 billion committed, unsecured, one year bridge loan facility, which was extendible at the option of the Company for an additional six month term. In August 2008, the Company used US$255 million from this facility to fund a portion of the Ravenswood acquisition and cancelled the remainder of the commitment. In February 2009, the US$255 million was repaid and the facility was cancelled.

NOTE 21 ASSET RETIREMENT OBLIGATIONS

The estimated undiscounted cash flows required to settle the asset retirement obligations with respect to the regulated and non-regulated operations in the Pipelines segment were $64 million at December 31, 2009 (2008 $69 million), calculated using an annual inflation rate ranging from one per cent to four per cent. The estimated fair value of these liabilities was $24 million at December 31, 2009 (2008 $31 million) after discounting the estimated cash flows at rates ranging from 5.4 per cent to 11.0 per cent. At December 31, 2009, the expected timing of payment for settlement of the obligations ranged from 2010 to 2029.

The estimated undiscounted cash flows required to settle the asset retirement obligations with respect to the Energy segment were $424 million at December 31, 2009 (2008 $427 million), calculated using an annual inflation rate ranging from two per cent to three per cent. The estimated fair value of this liability was $87 million at December 31, 2009 (2008 $85 million), after discounting the estimated cash flows at rates ranging from 5.4 per cent to eight per cent. At December 31, 2009, the expected timing of payment for settlement of the obligations ranged from 2017 to 2041.

Reconciliation of Asset Retirement Obligations[(1)]

(millions of dollars)	Pipelines	Energy	Total
Balance at January 1, 2007	9	36	45
New obligations and revisions in estimated cash flows	14	25	39
Accretion expense	2	2	4
Balance at December 31, 2007	25	63	88
New obligations and revisions in estimated cash flows	4	18	22
Accretion expense	2	4	6
Balance at December 31, 2008	31	85	116
New obligations and revisions in estimated cash flows	**(9)**	**(4)**	**(13)**
Accretion expense	**2**	**6**	**8**
Balance at December 31, 2009	**24**	**87**	**111**

(1) At December 31, 2009, Asset Retirement Obligations totalling $110 million (2008 $114 million) and $1 million (2008 $2 million) were included in Deferred Amounts and Accounts Payable, respectively.

NOTE 22 EMPLOYEE FUTURE BENEFITS

The Company sponsors DB Plans that cover the significant majority of employees. Pension 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 in the Canadian pension plan by a portion of the increase in the Consumer Price Index (CPI). Past service costs are amortized over the expected average remaining service life of employees, which is approximately eight years.

The Company also provides its employees with a Savings Plan in Canada, 401(k) Plans (DC Plans) in the U.S. and 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 was approximately 13 years at December 31, 2009. Contributions to the Savings Plan and DC Plans are expensed as incurred. The Company expensed $21 million in 2009 (2008 $21 million; 2007 $8 million) for the Savings Plan and DC Plans.

Total cash payments for employee future benefits, consisting of cash contributed by the Company to the DB Plans and other benefit plans, was $168 million in 2009 (2008 $90 million; 2007 $61 million), including $21 million in 2009 (2008 $21 million; 2007 $8 million) related to the Savings Plan and DC Plans.

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 at January 1, 2010, and the next required valuation will be as at January 1, 2011.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2009**	2008	**2009**	2008
Change in Benefit Obligation				
Benefit obligation beginning of year	**1,332**	1,462	**144**	155
Current service cost	**45**	52	**2**	2
Interest cost	**89**	80	**9**	8
Employee contributions	**4**	3	**1**	1
Benefits paid	**(70)**	(68)	**(8)**	(8)
Actuarial loss/(gain)	**107**	(261)	**10**	(21)
Foreign exchange rate changes	**(31)**	35	**(8)**	10
Plan amendment				(11)
Acquisition		29		8
Benefit obligation end of year	**1,476**	1,332	**150**	144
Change in Plan Assets				
Plan assets at fair value beginning of year	**1,193**	1,358	**26**	30
Actual return on plan assets	**206**	(222)	**5**	(10)
Employer contributions	**140**	62	**7**	7
Employee contributions	**4**	3	**1**	1
Benefits paid	**(70)**	(68)	**(8)**	(8)
Foreign exchange rate changes	**(26)**	32	**(4)**	6
Acquisition		28		
Plan assets at fair value end of year	**1,447**	1,193	**27**	26
Funded status plan deficit	**(29)**	(139)	**(123)**	(118)
Unamortized net actuarial loss	**329**	340	**37**	33
Unamortized past service costs	**21**	25	**(3)**	(1)
Accrued Benefit Asset/(Liability), Net of Valuation Allowance of Nil	**321**	226	**(89)**	(86)

The accrued benefit asset/(liability) net of valuation allowance of nil in the Company's Balance Sheet was as follows:

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2009**	2008	**2009**	2008
Intangibles and other assets	**323**	226		
Deferred amounts	**(2)**		**(89)**	(86)
	321	226	**(89)**	(86)

Included in the above benefit obligation and fair value of plan assets at December 31 were the following amounts for plans that are not fully funded:

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2009**	2008	**2009**	2008
Benefit obligation	**(390)**	(1,317)	**(150)**	(144)
Plan assets at fair value	**358**	1,178	**27**	26

Funded Status	**Plan Deficit**	**(32)**	(139)	**(123)**	(118)

The Company's expected contributions in 2010 are approximately $115 million for the pension benefit plans and approximately $28 million for the other benefit plans, Savings Plan and DC plans.

The following are estimated future benefit payments, which reflect expected future service:

(millions of dollars)	Pension Benefits	Other Benefits
2010	77	8
2011	81	9
2012	84	9
2013	87	10
2014	91	10
2015 to 2019	520	55

The significant weighted average actuarial assumptions adopted in measuring the Company's benefit obligations at December 31 were as follows:

	Pension Benefit Plans		Other Benefit Plans	
	2009	2008	**2009**	2008
Discount rate	**6.00%**	6.65%	**6.00%**	6.50%
Rate of compensation increase	**3.20%**	3.65%		

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan cost for years ended December 31 were as follows:

	Pension Benefit Plans			Other Benefit Plans		
	2009	2008	2007	**2009**	2008	2007
Discount rate	**6.65%**	5.30%	5.05%	**6.50%**	5.50%	5.20%
Expected long-term rate of return on plan assets	**6.95%**	6.95%	6.90%	**7.75%**	7.75%	7.75%
Rate of compensation increase	**3.25%**	3.60%	3.50%			

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and estimating future levels and volatility of returns. Asset class benchmark returns, asset mix and anticipated benefit payments from plan assets are also considered in determining 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.

A nine per cent annual rate of increase in the per capita cost of covered health care benefits was assumed for 2010 measurement purposes. The rate was assumed to decrease gradually to five per cent by 2019 and remain at this level thereafter. A one percentage point change 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	13	(12)

The Company's net benefit cost is as follows:

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31 (millions of dollars)	**2009**	2008	2007	**2009**	2008	2007
Current service cost	**45**	52	45	**2**	2	2
Interest cost	**89**	80	73	**9**	8	7
Actual return on plan assets	**(206)**	222	(33)	**(5)**	10	(2)
Actuarial loss/(gain)	**107**	(261)	(22)	**10**	(21)	8
Plan amendment					(11)	
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**35**	93	63	**16**	(12)	15
Difference between expected and actual return on plan assets	**107**	(316)	(51)	**3**	(12)	(1)
Difference between actuarial loss/(gain) recognized and actual actuarial loss/(gain) on accrued benefit obligation	**(101)**	280	47	**(8)**	23	(7)
Difference between amortization of past service costs and actual plan amendments	**4**	4	4		11	
Amortization of transitional obligation related to regulated business				**2**	2	2
Net Benefit Cost Recognized	**45**	61	63	**13**	12	9

The Company pension plans' weighted average asset allocations and target allocations by asset category were as follows:

December 31

	Percentage of Plan Assets		**Target Allocations**
Asset Category	**2009**	2008	**2009**
Debt securities	**40%**	48%	**35% to 60%**
Equity securities	**60%**	52%	**40% to 65%**
	100%	100%	

Debt securities included the Company's debt of $4 million (0.3 per cent of total plan assets) and $3 million (0.3 per cent of total plan assets) at December 31, 2009 and 2008, respectively. Equity securities included the Company's common shares of $8 million (0.6 per cent of total plan assets) and $4 million (0.3 per cent of total plan assets) at December 31, 2009 and 2008, 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 TCPL. The following amounts in this note, including those in the accompanying tables, represent TCPL's proportionate share with respect to these plans.

Total cash payments for employee future benefits, consisting of cash contributed by the Company's joint ventures to DB Plans and other benefit plans was $54 million in 2009 (2008 $42 million; 2007 $34 million).

The Company's joint ventures measure the benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuations of the pension plans for funding purposes were as at January 1, 2010, and the next required valuations will be as at January 1, 2011.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2009**	2008	**2009**	2008
Change in Benefit Obligation				
Benefit obligation beginning of year	**599**	789	**133**	165
Current service cost	**16**	27	**5**	8
Interest cost	**40**	42	**9**	9
Employee contributions	**6**	6		
Benefits paid	**(33)**	(37)	**(4)**	(4)
Actuarial loss/(gain)	**68**	(229)	**27**	(45)
Foreign exchange rate changes	**(1)**	1		
Benefit obligation end of year	**695**	599	**170**	133
Change in Plan Assets				
Plan assets at fair value beginning of year	**556**	626		
Actual return on plan assets	**63**	(78)		
Employer contributions	**50**	38	**4**	4
Employee contributions	**6**	6		
Benefits paid	**(33)**	(37)	**(4)**	(4)
Foreign exchange rate changes	**(1)**	1		
Plan assets at fair value end of year	**641**	556		
Funded status plan deficit	**(54)**	(43)	**(170)**	(133)
Unamortized net actuarial loss/(gain)	**113**	51	**25**	(3)
Unamortized past service costs			**2**	3
Accrued Benefit Asset/(Liability), Net of Valuation Allowance of Nil	**59**	8	**(143)**	(133)

The accrued benefit asset/(liability), net of valuation allowance of nil in the Company's Balance Sheet was as follows:

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2009**	2008	**2009**	2008
Intangibles and other assets	**60**	8		
Deferred amounts	**(1)**		**(143)**	(133)
	59	8	**(143)**	(133)

The following amounts were included at December 31 in the above benefit obligation and fair value of plan assets for plans that are not fully funded:

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2009**	2008	**2009**	2008
Benefit obligation	**(695)**	(594)	**(170)**	(133)
Plan assets at fair value	**641**	551		
Funded Status Plan Deficit	**(54)**	(43)	**(170)**	(133)

The expected total contributions of the Company's joint ventures in 2010 are approximately $57 million for the pension benefit plans and approximately $6 million for the other benefit plans.

The following are estimated future benefit payments, which reflect expected future service:

(millions of dollars)	Pension Benefits	Other Benefits
2010	40	5
2011	43	6
2012	47	6
2013	50	7
2014	53	8
2015 to 2019	315	48

The significant weighted average actuarial assumptions adopted in measuring the benefit obligations of the Company's joint ventures at December 31 were as follows:

	Pension Benefit Plans		Other Benefit Plans	
	2009	2008	**2009**	2008
Discount rate	**6.00%**	6.70%	**5.80%**	6.40%
Rate of compensation increase	**3.50%**	3.50%		

The significant weighted average actuarial assumptions adopted in measuring the net benefit plan costs of the Company's joint ventures for years ended December 31 were as follows:

	Pension Benefit Plans			Other Benefit Plans		
	2009	2008	2007	**2009**	2008	2007
Discount rate	**6.75%**	5.25%	5.00%	**6.40%**	5.15%	4.90%
Expected long-term rate of return on plan assets	**7.00%**	7.00%	7.00%			
Rate of compensation increase	**3.50%**	3.50%	3.50%			

A one percentage point change 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	(2)
Effect on post-employment benefit obligation	21	(18)

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)	**2009**	2008	2007	**2009**	2008	2007
Current service cost	**16**	27	28	**5**	8	10
Interest cost	**40**	42	40	**9**	9	8
Actual return on plan assets	**(63)**	78	1			
Actuarial loss/(gain)	**68**	(229)	(34)	**27**	(45)	(16)
Plan amendment						(2)
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**61**	(82)	35	**41**	(28)	
Difference between expected and actual return on plan assets	**25**	(122)	(44)			
Difference between actuarial loss/(gain) recognized and actual actuarial loss/(gain) on accrued benefit obligation	**(67)**	239	44	**(28)**	48	20
Difference between amortization of past service costs and actual plan amendments						3

Net Benefit Cost Recognized Related to Joint Ventures	**19**	35	35	**13**	20	23

The weighted average asset allocations and target allocations by asset category in the pension plans of the Company's joint ventures were as follows:

December 31	Percentage of Plan Assets		**Target Allocations**
Asset Category	**2009**	2008	**2009**
Debt securities	**40%**	44%	**40%**
Equity securities	**60%**	56%	**60%**
	100%	100%	

Debt securities included the Company's debt of $1 million (0.1 per cent of total plan assets) and $1 million (0.2 per cent of total plan assets) at December 31, 2009 and 2008, respectively. Equity securities included the Company's common shares of $4 million (0.6 per cent of total plan assets) and $3 million (0.6 per cent of total plan assets) at December 31, 2009 and 2008, 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 23 CHANGES IN OPERATING WORKING CAPITAL

Year ended December 31 (millions of dollars)	**2009**	2008	2007
Decrease/(increase) in accounts receivable	**315**	(126)	49
(Increase)/decrease in inventories	**(19)**	82	(6)
(Increase)/decrease in other current assets	**(249)**	(61)	33
(Decrease)/increase in accounts payable	**(153)**	131	(3)
Increase/(decrease) in accrued interest	**18**	102	(10)
(Increase)/Decrease in Operating Working Capital	**(88)**	128	63

NOTE 24 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 and equipment are approximately as follows:

Year ended December 31 (millions of dollars)	Minimum Lease Payments	Amounts Recoverable under Sub-leases	Net Payments
2010	86	(12)	74
2011	83	(9)	74
2012	81	(5)	76
2013	79	(4)	75
2014	76	(4)	72
2015 and thereafter	494	(3)	491
	899	(37)	862

The operating lease agreements for premises, services and equipment expire at various dates through 2052, with an option to renew certain lease agreements for periods of one year to ten years. Net rental expense on operating leases in 2009 was $91 million (2008 $52 million; 2007 $34 million).

TCPL's commitments under the Alberta PPAs are considered to be operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Future payments under these PPAs have been excluded from the above table, as these payments are dependent upon plant availability, among other factors. TCPL's share of power purchased under the PPAs in 2009 was $384 million (2008 $398 million; 2007 $391 million). The generating capacities and expiry dates of the PPAs are as follows:

	Megawatts	Expiry Date
Sundance A	560	December 31, 2017
Sundance B	353	December 31, 2020
Sheerness	756	December 31, 2020

TCPL and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business.

Bruce Power

Bruce A has signed commitments with third-party suppliers related to refurbishing and restarting Units 1 and 2. TCPL's share of these signed commitments, which extend over a two year period ending December 31, 2011, are as follows:

Year ended December 31 (millions of dollars)	
2010	256
2011	39
	295

Loan Aboriginal Pipeline Group

In 2003, the Mackenzie Delta gas producers, the Aboriginal Pipeline Group (APG) and TCPL reached an agreement governing TCPL's role in the Mackenzie Gas Pipeline (MGP) project. The project would result in a natural gas pipeline being constructed from Inuvik, Northwest Territories, to the northern border of Alberta, where it would connect with the Alberta System. Under the agreement, TCPL agreed to finance the APG for its one-third share of project pre-development costs. These costs, on a cumulative basis, are currently forecast to be between $150 million and $200 million. As at December 31, 2009, the Company had advanced $143 million to the APG.

TCPL and the other co-venture companies involved in the MGP continue to pursue approval of the proposed project, focusing on obtaining regulatory approval and the Canadian government's support of an acceptable fiscal framework. The regulatory process reached a milestone in late December 2009 with the release of the Joint Review Panel's report on environmental and socio-economic factors relating to the project. That report has been submitted into the NEB review process for approval of the project, which is scheduled to conclude in April 2010 with final arguments. A decision is currently expected by fourth quarter 2010.

In the event the co-venture group is unable to reach an agreement with the government on an acceptable fiscal framework, the parties will need to determine the appropriate next steps for the project. For TCPL, this may result in a reassessment of the carrying amount of the APG advances.

Other Commitments

At December 31, 2009, TCPL was committed to Pipelines capital expenditures totalling approximately $2.0 billion related primarily to construction costs of Keystone, expansion of the Alberta System and construction costs for Guadalajara and Bison.

At December 31, 2009, the Company was committed to Energy capital expenditures totalling approximately $1.3 billion related primarily to its share of the construction and development costs of Oakville, Bruce Power, Coolidge, Halton Hills and the second phase of Kibby Wind.

Contingencies

TCPL is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2009, the Company accrued approximately $67 million related to operating facilities. The accrued amount represents the Company's estimate of the amount it expects to expend to remediate the sites. However, additional liabilities may be incurred as assessments occur and remediation efforts continue.

TCPL and its subsidiaries are subject to various 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

TCPL, Cameco Corporation and BPC Generation Infrastructure Trust (BPC) have severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, a lease agreement and contractor services. The guarantees have terms ranging from 2018 to perpetuity. In addition, TCPL and BPC have severally guaranteed one-half of certain contingent financial obligations related to an agreement with the Ontario Power Authority to refurbish and restart Bruce A power generation units. The guarantees were provided as part of the reorganization of Bruce Power in 2005 and have terms ending in 2018 and 2019. In its 2009 decision to renew the operating licenses of

Bruce Power, the Canadian Nuclear Safety Commission (CNSC) ordered that it was no longer necessary for the major partners of Bruce Power, including TCPL, to provide financial assurances to Bruce Power to support its license obligations. After adjusting for the CNSC guarantees, TCPL's share of the potential exposure under these Bruce A and Bruce B guarantees was estimated at December 31, 2009 at $741 million. The fair value of these Bruce Power guarantees is estimated to be $82 million. The Company's exposure under certain of these guarantees is unlimited.

In addition to the guarantees for Bruce Power, the Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities related primarily to redelivery of natural gas, PPA payments and the payment of liabilities. TCPL's share of the potential exposure under these guarantees was estimated at December 31, 2009 to range from $351 million to a maximum of $632 million. The fair value of these guarantees is estimated to be $9 million which has been included in Deferred Amounts. The Company's exposure under certain of these guarantees is unlimited. For certain of these entities, any payments made by TCPL under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

NOTE 25 RELATED PARTY TRANSACTIONS

The following amounts are included in Due from TransCanada Corporation:

		2009		2008	
(millions of dollars)	Maturity Dates	**Outstanding December 31**	**Interest Rate**	Outstanding December 31	Interest Rate
Discount Notes[1]	2010	**1,959**	**0.6%**	1,529	2.1%
Credit Facility[2]		**(1,114)**	**2.3%**	(200)	4.8%
		845		1,329	

(1) Interest on the Discount Notes is equivalent to current commercial paper rates.

(2) TCPL has a demand revolving credit facility with TransCanada for $1.5 billion or a U.S. dollar equivalent amount bearing interest at the Royal Bank of Canada prime rate per annum or the U.S. base rate per annum as per the terms of the agreement. This facility may be withdrawn at any time at TransCanada's option.

The following amounts are included in Due to TransCanada Corporation:

		2009		2008	
(millions of dollars)	Maturity Dates	**Outstanding December 31**	**Interest Rate**	Outstanding December 31	Interest Rate
Credit Facility[1]	2012	**2,069**	**1.3%**	1,621	5.5%

(1) TransCanada has a $2.5 billion, unsecured credit facility agreement with TCPL, bearing interest at the Bankers' Acceptance rate plus 65 basis points or the Reuters prime rate; either at TCPL's option. Interest on the outstanding balance of $2.1 billion as at December 31, 2009 was at the Bankers' Acceptance rate plus 65 basis points.

In 2009, Interest Expense included $52 million (2008 $76 million; 2007 $72 million) of interest expense and $20 million (2008 $55 million; 2007 $30 million) of interest income as a result of transactions with TransCanada. At December 31, 2009, Accounts Payable included $2 million of interest payable to TransCanada (2008 $2 million) and $3 million of interest receivable from TransCanada (2008 $12 million).

The Company made interest payments of $52 million in 2009 (2008 $76 million; 2007 $68 million).

NOTE 26 SUBSEQUENT EVENTS

Subsequent events have been assessed up to February 22, 2010, which is the date the financial statements were available for issuance.

TEN YEAR FINANCIAL HIGHLIGHTS

(millions of dollars except where indicated)	**2009**	2008	2007	2006	2005	2004	2003	2002	2001	2000
Income Statement										
Revenues	**8,966**	8,619	8,828	7,520	6,124	5,497	5,636	5,225	5,285	4,384
EBITDA										
Pipelines	**3,122**	3,315	3,077	2,780	3,001	2,846	2,857	2,815	2,702	2,705
Energy	**1,132**	1,169	970	880	883	621	458	373	383	199
Corporate	**(117)**	(104)	(102)	(85)	(87)	(59)	(65)	(63)	(82)	(77)
	4,137	4,380	3,945	3,575	3,797	3,408	3,250	3,125	3,003	2,827
Depreciation	**(1,377)**	(1,247)	(1,237)	(1,117)	(1,041)	(972)	(954)	(876)	(811)	(737)
EBIT	**2,760**	3,133	2,708	2,458	2,756	2,436	2,296	2,249	2,192	2,090
Interest expense and other	**(1,005)**	(1,100)	(993)	(912)	(916)	(945)	(959)	(963)	(1,004)	(1,073)
Income taxes	**(376)**	(591)	(483)	(475)	(610)	(491)	(514)	(517)	(480)	(354)
Net income	**1,379**	1,442	1,232	1,071	1,230	1,000	823	769	708	663
Preferred share dividends	**(22)**	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(35)
Net income applicable to common shares										
Continuing operations	**1,357**	1,420	1,210	1,049	1,208	978	801	747	686	628
Discontinued operations				28		52	50		(67)	61
	1,357	1,420	1,210	1,077	1,208	1,030	851	747	619	689
Cash Flow Statement										
Funds generated from operations	**3,044**	2,992	2,603	2,374	1,950	1,701	1,822	1,843	1,625	1,484
(Increase)/decrease in operating working capital	**(88)**	128	63	(503)	79	28	93	92	(487)	437
Net cash provided by operations	**2,956**	3,120	2,666	1,871	2,029	1,729	1,915	1,935	1,138	1,921
Capital expenditures and acquisitions	**6,319**	6,363	5,874	2,042	2,071	2,046	965	851	1,082	1,144
Disposition of assets, net of current income taxes		28	35	23	671	410			1,170	2,233
Cash dividends paid on common and preferred shares	**998**	817	725	639	608	574	532	488	440	458
Balance Sheet										
Assets										
Plant, property and equipment										
Pipelines	**23,638**	20,700	18,280	17,141	16,528	17,306	16,064	16,158	16,562	16,937
Energy	**9,158**	8,435	5,127	4,302	3,483	1,421	1,368	1,340	1,116	776
Corporate	**83**	54	45	44	27	37	50	64	66	111
Total assets										
Continuing operations	**44,670**	40,735	31,737	26,386	24,113	22,414	20,873	20,416	20,255	20,238
Discontinued operations						7	11	139	276	5,007
Total assets	**44,670**	40,735	31,737	26,386	24,113	22,421	20,884	20,555	20,531	25,245
Capitalization										
Long-term debt	**16,186**	15,368	12,377	10,887	9,640	9,749	9,516	8,899	9,444	10,008
Junior subordinated notes	**1,036**	1,213	975							
Preferred securities				536	536	554	598	944	950	1,208
Non-controlling interests	**785**	805	610	366	394	311	324	288	286	257
Preferred shares	**389**	389	389	389	389	389	389	389	389	389
Common shareholders' equity	**14,483**	12,574	9,664	7,618	7,164	6,484	6,044	5,747	5,426	5,211

Per Common Share Data (dollars)										
Net income basic										
Continuing operations	**$2.20**	$2.59	$2.33	$2.17	$2.50	$2.03	$1.66	$1.56	$1.44	$1.32
Discontinued operations				0.06		0.11	0.11		(0.14)	0.13
	$2.20	$2.59	$2.33	$2.23	$2.50	$2.14	$1.77	$1.56	$1.30	$1.45
Net income diluted										
Continuing operations	**$2.20**	$2.59	$2.33	$2.17	$2.50	$2.03	$1.66	$1.55	$1.44	$1.32
Discontinued operations				0.06		0.11	0.11		(0.14)	0.13
	$2.20	$2.59	$2.33	$2.23	$2.50	$2.14	$1.77	$1.55	$1.30	$1.45
Per Preferred Share Data (dollars)										
Dividends declared:										
Series U Cumulative First Preferred Shares	**$2.80**	$2.80	$2.80	$2.80	$2.80	$2.80	$2.80	$2.80	$2.80	$2.80
Series Y Cumulative First Preferred Shares	**$2.80**	$2.80	$2.80	$2.80	$2.80	$2.80	$2.80	$2.80	$2.80	$2.80
Financial Ratios										
Earnings to fixed charges[1]	**2.0**	2.7	2.6	2.6	2.9	2.5	2.3	2.3	2.1	1.9

(1) The earnings to fixed charges ratio is determined by dividing earnings by fixed charges. Earnings is calculated as the sum of EBIT and interest income and other, less income attributable to non-controlling interests (excluding non-controlling interests with interest expense) and undistributed earnings of investments accounted for by the equity method. Fixed charges is calculated as the sum of interest expense, interest expense of joint ventures and capitalized interest.

TRANSCANADA PIPELINES LIMITED

RECONCILIATION TO UNITED STATES GAAP

December 31, 2009

AUDITORS' REPORT ON RECONCILIATION TO UNITED STATES GAAP

To the Board of Directors of TransCanada Pipelines Limited

On February 22, 2010, we reported on the consolidated balance sheets of TransCanada Pipelines Limited as at December 31, 2009 and 2008, and the consolidated statements of income, comprehensive income, accumulated other comprehensive income, shareholders' equity and cash flows for each of the years in the three-year period ended December 31, 2009, which are included in the Annual Report on Form 40-F. In connection with our audits 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 22, 2010

TRANSCANADA PIPELINES LIMITED
RECONCILIATION TO UNITED STATES GAAP

The audited consolidated financial statements of TransCanada Pipelines Limited (TCPL or the Company) for the year ended December 31, 2009 have been prepared in accordance with Canadian generally accepted accounting principles (GAAP), which, in some respects, differ from United States (U.S.) GAAP.

The effects of significant differences between Canadian and U.S. GAAP on the Company's consolidated financial statements for the years ended December 31, 2009, 2008 and 2007 are described below and should be read in conjunction with TCPL's audited consolidated annual financial statements prepared in accordance with Canadian GAAP.

Reconciliation of Net Income and Comprehensive Income

Year Ended December 31 (millions of dollars, except per share amounts)	**2009**	2008	2007
Net Income in Accordance with Canadian GAAP	**1,379**	1,442	1,232
U.S. GAAP adjustments:			
Net income attributable to non-controlling interests[1]	**74**	108	75
Unrealized (gain)/loss on natural gas inventory held in storage[2]	**(3)**	32	(25)
Tax impact of unrealized (gain)/loss on natural gas inventory held in storage	**1**	(11)	8
Dilution gain[3]	**(29)**		
Tax impact of dilution gain	**11**		
Tax expense due to a change in tax legislation substantively enacted in Canada[4]			(12)
Other			6
Net Income in Accordance with U.S. GAAP	**1,433**	1,571	1,284
Less: net income attributable to non-controlling interests[1]	**(74)**	(108)	(75)
Less: preferred share dividends	**(22)**	(22)	(22)
Net Income Attributable to Common Shares In Accordance with U.S. GAAP	**1,337**	1,441	1,187
Other Comprehensive (Loss)/Income in Accordance with Canadian GAAP	**(160)**	(99)	(187)
U.S. GAAP adjustments:			
Change in funded status of postretirement plan liability[5]	**7**	(49)	(48)
Tax impact of change in funded status of postretirement plan liability	**(2)**	10	8
Change in equity investment funded status of postretirement plan liability	**(71)**	158	32
Tax impact of change in equity investment funded status of postretirement plan liability	**23**	(51)	(11)
Other			(14)
Comprehensive Income in Accordance with U.S. GAAP	**1,134**	1,410	967

Condensed Balance Sheet in Accordance with U.S. GAAP[6]

December 31 (millions of dollars)	2009	2008
Current assets[2]	**3,463**	4,921
Long-term investments[5][6]	**4,873**	5,221
Plant, property and equipment[7]	**27,695**	22,901
Goodwill	**3,644**	4,258
Regulatory assets[5][8]	**1,675**	1,810
Intangibles and other assets[5][9]	**2,041**	1,608
	43,391	40,719
Current liabilities[4][7]	**4,470**	6,314
Due to TransCanada Corporation	**2,069**	
Deferred amounts[5][6]	**899**	1,238
Regulatory liabilities	**381**	317
Deferred income taxes[2][5][8]	**2,839**	2,632
Long-term debt and junior subordinated notes[9]	**17,335**	16,664
	27,993	27,165
Shareholders' equity:		
Common shares	**10,649**	8,974
Preferred shares	**389**	389
Non-controlling interests[1]	**785**	805
Contributed surplus[3]	**353**	284
Retained earnings[2][3][4]	**4,094**	3,771
Accumulated other comprehensive income[5][10]	**(872)**	(669)
	15,398	13,554
	43,391	40,719

Reconciliation of Accumulated Other Comprehensive Income

December 31 (millions of dollars)	2009	2008	2007
Accumulated Other Comprehensive Income in Accordance with Canadian GAAP	**(632)**	(472)	(373)
U.S. GAAP adjustments:			
Change in funded status of postretirement plan liability, net of tax[5]	**(152)**	(157)	(118)
Change in equity investment funded status of post-retirement plan liability, net of tax	**(88)**	(40)	(147)
Accumulated Other Comprehensive Income in Accordance with U.S. GAAP	**(872)**	(669)	(638)

(1) As required by U.S. GAAP, the Company has reclassified its non-controlling interests on the balance sheet and income statement. On the balance sheet, non-controlling interests is presented in the equity section and on the income statement, consolidated net income includes both the Company's and the non-controlling interests' share of net income. In addition, consolidated net income attributable to the Company and the non-controlling interests are separately disclosed. As required, these reclassifications have been applied retrospectively in the U.S. GAAP financial statements.

(2) In accordance with Canadian GAAP, natural gas inventory held in storage is recorded at its fair value. Under U.S. GAAP, inventory is recorded at lower of cost or market.

(3) Under U.S. GAAP, the dilution gain resulting from TC PipeLines, LP's equity issuance is accounted for as an equity transaction. Under Canadian GAAP, the dilution gain is included in net income.

(4)

In accordance with Canadian GAAP, the Company recorded current income tax benefits resulting from substantively enacted Canadian federal income tax legislation. Under U.S. GAAP, the legislation must be fully enacted for income tax adjustments to be recorded.

(5) Under U.S. GAAP, an employer is required to recognize the overfunded or underfunded status of a defined benefit postretirement plan as an asset or liability in its statement of financial position and to recognize changes in that funded status, through Other

Comprehensive Income (OCI), in the year in which the changes occur. The amounts recognized in the Company's balance sheet for its defined benefit plan and other postretirement benefits are as follows:

December 31 (millions of dollars)	**2009**	2008
Non-current liabilities	**152**	259

Pre-tax amounts recognized in Accumulated Other Comprehensive Income (AOCI) are as follows:

	2009			2008			2007		
December 31 (millions of dollars)	**Pension Benefits**	**Other Benefits**	**Total**	Pension Benefits	Other Benefits	Total	Pension Benefits	Other Benefits	Total
Net loss	**170**	**21**	**191**	173	22	195	120	15	135
Prior service cost	**10**	**2**	**12**	11	4	15	12	14	26
	180	**23**	**203**	184	26	210	132	29	161

Pre-tax amounts recorded in OCI were as follows:

	2009			2008		
December 31 (millions of dollars)	**Pension Benefits**	**Other Benefits**	**Total**	Pension Benefits	Other Benefits	Total
Amortization of net loss from AOCI to OCI	**(5)**	**(1)**	**(6)**	(1)	(1)	(2)
Amortization of prior service cost/(credit) from AOCI to OCI	**(2)**		**(2)**	(2)	(1)	(3)
Funded status adjustment	**2**	**(1)**	**1**	56	(2)	54
	(5)	**(2)**	**(7)**	53	(4)	49

The funded status based on the accumulated benefit obligation for all defined benefit pension plans is as follows:

December 31 (millions of dollars)	**2009**	2008
Accumulated benefit obligation	**1,326**	1,136
Fair value of plan assets	**1,447**	1,193
Funded Status surplus	**121**	57

Included in the above accumulated benefit obligation and fair value of plan assets are the following amounts in respect of plans that are not fully funded.

December 31 (millions of dollars)	**2009**	2008
Accumulated benefit obligation	**176**	182
Fair value of plan assets	**165**	162
Funded Status (deficit)	**(11)**	(20)

The estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal year are $4 million and $2 million, respectively. The estimated net loss and prior service cost for the other postretirement plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal year is $1 million and $1 million, respectively.

The rate used to discount pension and other postretirement benefit plan obligations was based on a yield curve from Moody's corporate AA bond yields at December 31, 2009 developed by the Company's third party actuary. This yield curve is used to develop spot rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other postretirement obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

(6)

Under Canadian GAAP, the Company accounts for certain investments using the proportionate consolidation basis of accounting whereby the Company's proportionate share of assets, liabilities, revenues, expenses and cash flows are included in the Company's financial statements. U.S. GAAP does not allow the use of proportionate consolidation and requires that such investments be recorded on an equity basis of accounting. Information on the balances that have been proportionately consolidated is located in Note 8 to the Company's Canadian GAAP 2009 audited consolidated annual financial statements. As a consequence of using equity accounting for U.S. GAAP, the Company is required to reflect an additional liability of $261 million at December 31, 2009 (December 31, 2008 $51 million) for the estimated fair value of certain guarantees related to debt and other performance commitments of the joint venture operations that were not required to be recorded when the underlying liability was reflected on the balance sheet under the proportionate consolidation method of accounting. The distributed earnings from long-term investments for the year ended December 31, 2009 were $265 million (2008 $295 million; 2007 $376 million). The undistributed earnings from long-term investments for the year ended December 31, 2009 were $1,174 million (2008 $892 million).

(7) Under Canadian GAAP, the Company's purchase of ConocoPhilips' remaining 20 per cent interest in each of TransCanada Keystone Pipeline Limited Partnership and TransCanada Keystone Pipeline, LP (together, Keystone) is considered an asset purchase. Under U.S. GAAP, this transaction is considered a business combination. The purchase price was allocated to Plant, Property and Equipment (US$734 million) and Short-term Debt (US$197 million) using fair values of the net assets at the date of acquisition. There is no U.S. GAAP difference as no gain or loss was created.

(8) Under U.S. GAAP, the Company is required to record a deferred income tax liability for its cost-of-service regulated businesses and a corresponding regulatory asset. Effective January 1, 2009, the Company adopted accounting policies consistent with U.S. GAAP for its Canadian GAAP financial statements, which eliminated the U.S. GAAP difference subsequent to December 31, 2008.

(9) In accordance with U.S. GAAP, debt issue costs are recorded as a deferred asset rather than being included in long-term debt as required by Canadian GAAP.

Hedging Instruments and Activities

The Company adopted the U.S. standards for disclosures regarding derivatives and hedging effective January 1, 2009. This standard is intended to enhance the current disclosure requirements to provide more information about how derivatives and hedging activities affect an entity's financial position, financial performance and cash flows. Many of these disclosures are provided in the Company's consolidated financial statements prepared under Canadian GAAP. Additional required information is provided below.

Derivatives in Cash Flow and Net Investment Hedging Relationships

	Cash Flow Hedges				Net Investment Hedges
Year ended December 31, 2009 (millions of dollars, pre-tax)	**Power**	**Natural Gas**	**Foreign Exchange**	**Interest**	**Foreign Exchange**
Amount of gains/(losses) recognized in OCI on derivative instruments (effective portion)	129	(29)	(20)	4	382
Amount of (losses)/gains on derivative instruments reclassified from AOCI into income (effective portion)	(63)	18		30	(1)
Amount of (losses)/gains recognized in income on derivative instruments (ineffective portion and amount excluded from effectiveness testing)	(5)				(2)

(1) Location of gain/(loss) is gain/(loss) on sale of subsidiary.

(2) Location of gain/(loss) is other income/(expense).

Derivative contracts entered into to manage market risk often contain financial assurances provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade. Based on contracts in place and market prices at December 31, 2009, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a net liability position is $122 million, for which the Company has provided collateral of $8 million in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on December 31, 2009, the Company may be required to provide additional collateral of $114 million to its counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds. The Company has sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Postretirement Benefit Plan Assets

Pension assets are invested in high-quality asset classes designed to maximize returns and diversify risk, with consideration given to the demographics of the plan members. Asset mix strategies may incorporate equity securities, debt securities, real estate and derivatives that hedge against risk. Derivatives are not used for speculative purposes and the use of leveraged derivatives is prohibited.

All investments are measured at fair value using market prices. Where the fair value cannot be readily determined by reference to generally available price quotations, the fair value is determined by considering the discounted cash flows on a risk-adjusted basis and by comparison to similar assets which are publicly traded.

The following table presents plan assets for defined benefit plans and other postretirement benefits measured at fair value as at December 31, 2009 categorized as follows:

(unaudited, millions of dollars)	Quoted Prices in Active Markets (Level I)	Significant Other Observable Inputs (Level II)	Significant Unobservable Inputs (Level III)	Total	Percentage of Total Portfolio
Asset Category					
Cash and cash equivalents	63			63	4%
Equity Securities:					
Canadian	441			441	30%
U.S.	250	15		265	18%
International	157	40		197	13%
Fixed Income Securities:					
Canadian Bonds:					
Federal	276			276	19%
Provincial	110			110	8%
Municipal	2			2	
Corporate	56			56	4%
U.S. Bonds:					
State		21		21	1%
Corporate	8	13		21	1%
Mortgage Backed		22		22	2%
	1,363	111		1,474	100%

Other Fair Value Measurements

Note 18 to the Company's Canadian GAAP 2009 audited consolidated annual financial statements contains fair value hierarchy information with respect to financial assets and liabilities. Other liabilities, measured at fair value on a recurring basis, are classified in the Level III fair value category as follows:

(millions of dollars)	ARO[(1)]	Guarantees[(2)]
Balance, at December 31, 2008		
Transfers in	(116)	(60)
Accretion	(8)	
Total realized and unrealized gains/(losses) included in Balance Sheet	12	(204)
New contracts entered into during the period		(22)
Contracts settled during the period	1	16
Balance, at December 31, 2009	(111)	(270)

(1) The fair value of asset retirement obligations is recognized in Plant, Property and Equipment with offsetting amounts in Accounts Payable and Deferred Amounts. The fair value is calculated by discounting the estimated cash flows required to settle the asset retirement obligations.

(2) The fair value of guarantees is recognized in Long-term Investments with an offsetting amount to Deferred Amounts. No amounts were recognized in earnings for the periods presented. Prior to June 30, 2009, the fair value was included in the Level II fair value category.

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)	2009	2008
Deferred Tax Liabilities		
Difference in accounting and tax bases of plant, equipment and power purchase arrangements	**2,317**	2,182
Taxes on future revenue requirement	**338**	387
Investments in subsidiaries and partnerships	**358**	313
Unrealized foreign exchange gains on long-term debt	**96**	14
Pension benefit	**18**	6
Other comprehensive income	**7**	
Other	**88**	81
	3,222	2,983
Deferred Tax Assets		
Deferred amounts	**42**	119
Other post-employment benefits	**37**	38
Other comprehensive income	**56**	62
Non-capital loss carry-forwards	**148**	24
Unrealized foreign exchange losses on long-term debt		77
Other	**100**	108
	383	428
Less: Valuation allowance		77
	383	351
Net deferred tax liabilities	**2,839**	2,632

Below is the reconciliation of the annual changes in the total unrecognized tax benefit.

December 31 (millions of dollars)	2009	2008
Unrecognized tax benefits, beginning of year	**78**	70
Gross increases tax positions in prior years	**5**	13
Gross decreases tax positions in prior years	**(3)**	(1)
Gross increases current year positions	**15**	18
Settlements	**(35)**	(19)
Lapses of statute of limitations	**(8)**	(3)
Unrecognized tax benefits, end of year	**52**	78

TCPL expects the enactment of certain Canadian federal tax legislation in the next twelve months which is expected to result in a favourable income tax adjustment of approximately $12 million. Otherwise, subject to the results of audit examinations by taxing authorities and other legislative amendments, TCPL does not anticipate further adjustments to the unrecognized tax benefits during the next twelve months that would have a material impact on its financial statements.

TCPL and its subsidiaries are subject to either Canadian federal and provincial income tax, U.S. federal, state and local income tax or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2005. Substantially all material U.S. federal income tax matters have been concluded for years through 2005 and U.S. state and local income tax matters through 2003.

TCPL's continuing practice is to recognize interest and penalties related to income tax uncertainties in income tax expense. Included in net tax expense for the year ended December 31, 2009 is $8 million of interest income and nil for penalties (December 31, 2008 $10 million for interest and nil for penalties). At December 31, 2009, the Company had $16 million accrued for interest and nil accrued for penalties (December 31, 2008 $24 million accrued for interest and nil accrued for penalties).

Changes in Accounting Policies

In January 2010, FASB issued new guidance on "Fair Value Measurements and Disclosures" which requires further disclosures with respect to recurring or nonrecurring fair value measurements. In particular, transfers in and out of Levels I and II in the fair value hierarchy must be disclosed as well as information about valuation techniques and inputs used to measure fair value for both Level II and Level III measurements. This guidance is effective for fiscal years ending after December 15, 2009 and the Company adopted these standards for its 2009 year-end reporting by expanding its fair value disclosure. In addition, activity in Level III including purchases, sales, issuances and settlements must be disclosed on a gross basis for interim periods beginning after December 15, 2010.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Internal control over financial reporting is a process designed by or under the supervision of senior management of TransCanada PipeLines Limited ("TCPL"), and effected by the Board of Directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and preparation of consolidated financial statements for external purposes in accordance with Canadian generally accepted accounting principles, including a reconciliation to U.S. GAAP.

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting, no matter how well designed, has inherent limitations and can only provide reasonable assurance with respect to the preparation and fair presentation of published financial statements. Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on this evaluation, management concluded that internal control over financial reporting is effective as at December 31, 2009, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

In 2009, there was no change in TCPL's internal control over financial reporting that materially affected or is reasonably likely to materially affect TCPL's internal control over financial reporting.

KPMG LLP, the independent auditors appointed by the shareholder of TCPL, who have audited the consolidated financial statements of TCPL, have also audited the effectiveness of TCPL's internal control over financial reporting as of December 31, 2009 and have issued the report entitled "Report of Independent Registered Public Accounting Firm".

February 22, 2010

/s/ HAROLD N. KVISLE

Harold N. Kvisle
President and
Chief Executive Officer

/s/ GREGORY A. LOHNES

Gregory A. Lohnes
Executive Vice-President and
Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of TransCanada PipeLines Limited

We have audited TransCanada PipeLines Limited's internal control over financial reporting as of December 31, 2009, based on the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have conducted our audits on the consolidated financial statements in accordance with Canadian generally accepted auditing standards and in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our report dated February 22, 2010 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
Chartered Accountants
Calgary, Canada

February 22, 2010

COMMENTS BY AUDITORS FOR UNITED STATES READERS ON CANADA UNITED STATES REPORTING DIFFERENCES

To the Board of Directors of TransCanada PipeLines Limited

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) that refers to the audit report on the Company's internal control over financial reporting. Our report to the shareholders dated February 22, 2010 is expressed in accordance with Canadian reporting standards, which do not require a reference to the audit report on the Company's internal control over financial reporting in the financial statement auditors' report.

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, whether as a result of the adoption of a new accounting pronouncement or otherwise, that has a material effect on the consistency of the Company's financial statements, such as the change described in note 3 to the consolidated financial statements as at December 31, 2009 and for the three-years then ended. Our report to the shareholders dated February 22, 2010 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 22, 2010

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